Issues paper

Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-2014

Demand management incentive scheme
Control mechanisms for alternative control services
Approach to determining materiality for possible pass through events

November 2007

AUSTRALIAN ENERGY REGULATOR

Contents

Shortened forms

AER	Australian Energy Regulator
Capex	Capital expenditure
DNSP	Distribution Network Service Provider
ICRC	Independent Competition & Regulatory Commission (ACT)
IPART	Independent Prices and Regulatory Tribunal (NSW)
NEM	National Electricity Market
NER	National Electricity Rules
Opex	Operating expenditure
SCO	Ministerial Council on Energy Standing Committee of Officials

Summary

The Australian Energy Market Agreement establishes that the Australian Energy Regulator (AER) will assume responsibility for the economic regulation of electricity distribution services in the National Electricity Market (NEM). This is expected to take place by early 2008. The first distribution determinations the AER will be required to make will be for the regulatory control period 2009-2014 in relation to the following Distribution Network Service Providers (DNSPs):

- ActewAGL
- Country Energy
- EnergyAustralia
- Integral Energy

(the ACT and NSW DNSPs).

Amendments to the National Electricity Rules (NER) are currently being drafted that will set out the regulatory framework under which the AER will regulate distribution services. These amendments will not take effect with sufficient time for them to be fully applied for the distribution determinations for the ACT and NSW DNSPs. Consequently, transitional arrangements will apply to the ACT and NSW DNSPs.

This paper is based on the AER's understanding of the requirements of the transitional arrangements that will apply to the ACT and NSW DNSPs. This understanding has been developed on the basis of:

- Proposed amendments to Chapter 6[1]
- Table 3 of the response of the Ministerial Council on Energy Standing Committee of Officials (SCO) to stakeholder comments on the general transitional arrangements and NSW/ACT transitional arrangements[2]
- Liaison with the SCO regarding the content of transitional arrangements.

The AER understands that a draft of these transitional arrangements will be made publicly available shortly. The AER will review the transitional arrangements when they are released, and may modify its proposed approaches to issues if the final version of the arrangements differs to the AER's understanding of its likely content.

This paper discusses issues associated with applying the following in the AER's distribution determination for ACT and NSW DNSPs for the 2009-2014 regulatory control period:

- A demand management incentive scheme
- A control mechanism for alternative control services
- A guideline on the AER's likely approach to determining materiality in the context of possible pass through events.

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1 Available at www.mce.gov.au.

2 See SCO Response to Draft NER (1 August 2007) at www.mce.gov.au.

The views expressed in this paper are those of AER staff, and have not yet been considered by the AER Board. The AER is seeking submissions on the issues discussed in this paper, and will develop a preliminary position after considering any submissions. Further submissions will be sought at the time of releasing a preliminary position.

The AER has also released a separate consultation paper setting out preliminary positions with respect to various models, incentive schemes and guidelines to be applied in the 2009-2014 distribution determinations.

Consultation processes

The AER's preparations to assume responsibility for the economic regulation of electricity distribution services in the NEM will include the release in November 2007 of four papers for consultation: two papers relevant only to the distribution determination that will apply to the ACT and NSW DNSPs for the 2009-2014 regulatory control period, and two papers relevant to the entire NEM. These papers are:

- This issues paper with respect to matters of relevance to the ACT and NSW distribution determinations for the 2009-2014 regulatory period
- A preliminary position paper outlining preliminary positions with respect to various issues of relevance to the ACT and NSW distribution determinations for the 2009-2014 regulatory period
- An issues paper discussing the development of a service target performance incentive scheme that will potentially apply across the NEM
- An issues paper discussing the other models, incentive schemes and guidelines that will potentially apply across the NEM.

Due to the timing of the ACT and NSW distribution determinations, the AER will have to finalise the basis on which it will make its decisions with respect to these determinations before it prepares guidance on the conduct of future distribution determinations in other parts of the NEM. Consequently, the guidelines relevant to the ACT and NSW distribution determinations will be completed before those under the general Chapter 6. The positions that the AER reaches with respect to the matters discussed in this paper for the ACT and NSW distribution determinations will not be determinative of the positions it will reach when determining a position to apply in other parts of the NEM.

Processes for the ACT and NSW distribution determinations

Issues paper for ACT and NSW

The AER has released this issues paper in order to develop its understanding of the issues surrounding the matters discussed in this paper. The AER proposes to release a further preliminary position paper after considering any submissions. The AER will seek further submissions at the time it releases a preliminary position on these matters. A final decision on the matters discussed in the issues paper will be made after the amendments to the NER take effect.

Preliminary position paper for ACT and NSW

The AER is seeking submissions on its preliminary positions. The AER proposes to make final decisions on the matters outlined in its preliminary position paper following consideration of the submissions received, and does not propose to release further written guidance on its likely approaches prior to making a final decision. However, the AER is willing to engage with stakeholders until a final decision is made.

Request for submissions on this issues paper

Interested parties are invited to make written submissions to the AER on the issues discussed in this paper by the close of business **Monday, 10 December 2007**. The AER is mindful that this timeframe is short, and notes that further submissions will be sought following the development of a preliminary position.

Submissions can be sent electronically to AERInquiry@aer.gov.au. Alternatively, written submissions can be sent to:

Mr Mike Buckley
General Manager
Network Regulation North Branch
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

The AER prefers that all submissions be in an electronic format and publicly available, to facilitate an informed, transparent and robust consultation process. Accordingly, submissions will be treated as public documents and posted on the AER's website, www.aer.gov.au except and unless prior arrangements are made with the AER to treat the submission, or portions of it, as confidential.

Any enquiries about the issues paper, or about lodging submissions, should be directed to the Network Regulation North Branch on (02) 6243 1233 or at the above email address.

1 Regulatory framework for ACT and NSW 2009-2014 distribution determination

1.1 Amendments to the National Electricity Rules

Jurisdictional regulators are currently responsible for the economic regulation of electricity distribution services under Chapter 6 of the National Electricity Rules (NER). Amendments to the NER transferring this responsibility to the AER are expected to take effect in early 2008. These amendments will confer responsibility on the AER to make a 'distribution determination' in respect of each Distribution Network Service Providers (DNSP) operating in the National Electricity Market (NEM).

The first distribution determinations that the AER will be required to make under the amended NER will apply to the DNSPs that operate in the ACT and NSW, for the regulatory control period 2009-2014. These DNSPs are:

- ActewAGL
- Country Energy
- EnergyAustralia
- Integral Energy

(the ACT and NSW DNSPs).

The AER must make its distribution determinations in respect of the ACT and NSW DNSPs by 1 May 2009. Unless otherwise indicated, references in this paper to a 'distribution determination' are to the distribution determinations that the AER will make in relation to DNSPs operating in the ACT and NSW for the 2009-2014 regulatory control period.

This paper discusses issues with respect to matters that are relevant to these distribution determinations. Any views expressed in this paper are those of AER staff, and have not yet been considered by the AER Board. Further submissions on the matters discussed in this paper will be sought following the release of a preliminary position paper.

1.2 Transitional Rules for ACT and NSW DNSPs

Amendments to Chapter 6 of the NER are currently being drafted that will change the economic regulatory framework for distribution services in the NEM. The Ministerial Council on Energy Standing Committee of Officials (SCO) has noted that the ideal scenario would be for the ACT and NSW distribution determinations to be made under the amended Chapter 6 that will apply across the NEM, however, time constraints on the preparation and assessment of regulatory proposals will not allow this to occur. [3] Accordingly, SCO has decided that transitional arrangements for the ACT and NSW distribution determinations are necessary. These arrangements will be

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[3] SCO Response to Draft NER (1 August 2007), p.79.

set out in Chapter 11 of the amended NER. This means that rather than the amended Chapter 6 being applied to the distribution determination, Chapter 11 of the amended NER will apply.

Rather than the amended Chapter 6 being applied to the ACT and NSW distribution determinations, Chapter 11 of the NER will provide that a modified version of the new Chapter 6 - a transitional Chapter 6 - will apply. In this paper a reference to the 'general Chapter 6' means the new Chapter 6 that will apply across the NEM and take effect early next year. A reference to the 'transitional Chapter 6' or 'transitional Rules' is a reference to the rules that will apply to the ACT and NSW distribution determinations. The AER understands that a draft of the transitional Chapter 6 will be made publicly available by SCO shortly.

The AER understands that SCO's approach to developing arrangements for the ACT and NSW distribution determination has generally been to apply the national arrangements in the general Chapter 6 where feasible. SCO's explanatory material accompanying the release of the exposure draft of Chapter 6 in April 2007 indicates that the general Chapter 6 has been developed with the objective of consistency with transmission where appropriate:

> To achieve the MCE's objective of consistency where appropriate, the Exposure Draft of distribution revenue Rules largely builds on the AEMC's approach to economic regulation of electricity transmission. The Exposure Draft takes into account differences in the nature of transmission and distribution networks, based on analysis of these differences undertaken during the development of the draft Rules.[4]

Where it is not feasible to apply the arrangements in the general Chapter 6, because of timing constraints, SCO's approach has been to adopt transitional arrangements, with the result that some provisions of transitional Chapter 6 will differ to those of the general Chapter 6. In recognition of the limited time available to consider alternative approaches to those in the general Chapter 6, the transitional Chapter 6 will largely preserve key elements of the current frameworks applied in the ACT and NSW.

In considering the issues discussed in this paper, the AER will take into account SCO's approach to the development of transitional arrangements. Unless there is sufficient time to consider and implement changes to existing arrangements, or there is a clear reason to change existing arrangements, the AER will generally consider maintaining the approaches taken by the Independent Competition and Regulatory Commission (ICRC) and the Independent Prices and Regulatory Tribunal (IPART) in the current regulatory period.

1.3 Consultation for ACT and NSW resets

Requirements of the NER

The transitional Chapter 6 will provide for various incentive schemes and guidelines to be prepared by the AER in advance of making the distribution determination that

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4 Standing Committee of Officials of the Ministerial Council on Energy, *Changes to the National Electricity Rules to establish an economic framework for the regulation of electricity distribution, Explanatory Material*, April 2007, available at www.mce.gov.au.

will apply to the ACT and NSW DNSPs. Among others, transitional Chapter 6 will provide for the following:

- A demand management incentive scheme may be published; however it may not be applied in the distribution determination if it is not published by 1 March 2008 or the date that is one month after the commencement of amendments to the NER (whichever is the later)
- A statement as to the AER's likely approach to the control mechanism for alternative control services must be published by 1 March 2008
- A guideline outlining the AER's likely approach to determining materiality in the context of possible pass through events may be published.

The transitional Chapter 6 will provide that in developing this incentive scheme and statement, the AER may carry out such consultation as it considers appropriate and may take into consideration any consultation carried out before the commencement date of the amendments to the NER. In view of the time available and the need to provide stakeholders with adequate opportunity to comment on matters relevant to the ACT and NSW distribution determinations, the AER considers it appropriate to commence consultation prior to commencement of the amendments to the NER.

The transitional Chapter 6 will provide that once finalised, the demand management incentive scheme and guideline on the approach to determining materiality may be amended. There is no scope in the transitional Rules to amend the statement as to the likely approach to and s for alternative control services.

The transitional arrangements will provide for the continuation of some arrangements that are currently in place. These include ring fencing and capital contributions arrangements. Cost allocation methodologies must be submitted by the ACT and NSW DNSPs to the AER after the NER take effect, however the AER is not required to release cost allocation guidelines for the ACT and NSW DNSPs. Consequently, the AER will not consult on these issues at this time.

Engagement with ACT and NSW DNSPs

The AER has been liaising with the ACT and NSW DNSPs for a number of months in anticipation of preparing the models and incentive schemes provided for under transitional Chapter 6. A consultation session was held on 21 June 2007 in which AER staff presented proposals for certain models and incentive schemes to be developed under the transitional Chapter 6. Following this consultation session, further meetings between the ACT and NSW DNSPs and the AER have occurred in which issues associated with the upcoming distribution determination, including the development of guidelines under transitional Chapter 6, were discussed.

Proposed consultation process

The AER will make decisions with respect to the matters referred to in this paper after the NER take effect. After considering any submissions on this issues paper, the AER proposes to issue a preliminary position on how the matters referred to in this paper should be applied in the distribution determination for ACT and NSW DNSPs. The AER will seek further submissions at the time of releasing its preliminary position. A final decision on these matters will be released by the AER after the amendments to the NER take effect.

Other consultation for ACT and NSW distribution determinations

In addition to the matters discussed in this paper, the AER is consulting on other matters provided for under transitional Chapter 6 through a separate preliminary position paper.

Separate consultation is being undertaken on the information requirements that will apply to the regulatory proposals the ACT and NSW DNSPs will be required to submit to the AER. The AER proposes to specify these requirements through regulatory information notices to be issued under the National Electricity Law, rather than through guidelines under the NER.

1.4 Consultation under general Chapter 6 of the NER

The general Chapter 6 of the NER will provide for the AER to develop various guidelines that may be applied to DNSPs across the NEM. [5] The guidelines of broad application will not be developed in time for them to be applied in the ACT and NSW distribution determinations. Consequently, the NER will require the AER to develop separate guidelines under transitional Chapter 6 that will apply for the upcoming regulatory control period for the ACT and NSW DNSPs.

This paper is relevant only to the guidelines that will be published for the ACT and NSW distribution determination under transitional Chapter 6 of the NER. Separate papers will be released relating to the guidelines under general Chapter 6 of the amended NER.

Given that the AER's guidelines under general Chapter 6 and transitional Chapter 6 will be informed by separate consultation processes, the guidelines under the two chapters may vary. The guidelines that the AER develops for the ACT and NSW distribution determination may, in some circumstances, provide guidance as to the AER's likely approach to guidelines under general Chapter 6. However, they will not be determinative of the AER's positions under general Chapter 6.

Although the guidelines developed under general Chapter 6 and transitional Chapter 6 may vary, there is scope to align the two sets of guidelines following the conclusion of the general Chapter 6 guidelines process. [6] Should differences arise in the guidelines under general Chapter 6 and transitional Chapter 6, it is possible to amend the transitional Chapter 6 guidelines following the conclusion of the general Chapter 6 guidelines process.

In summary, the AER will engage in separate consultation processes for the guidelines under general Chapter 6 and transitional Chapter 6. This paper is relevant to the guidelines that will be published under transitional Chapter 6 of the NER, and

[5] In this section, the term 'guidelines' is used to include guidelines, incentive schemes and models.

[6] A demand management incentive sharing scheme may be amended with the agreement of the ACT and NSW DNSPs. The guideline on materiality may be amended subject to such consultation as the AER considers appropriate. The transitional Rules will not provide scope to amend the statement as to the likely approach to the control mechanism for alternative control services.

the AER’s decisions on these matters will not determine the AER’s position on guidelines under general Chapter 6.

2 Demand management incentive scheme

2.1 Introduction

Demand management refers to any strategy to address growth in demand and/or peak demand. Network owners can seek to undertake demand management through a range of mechanisms, such as: incentives to customers to change their demand patterns, operational efficiency programs, load control technologies, or alternative sources of supply (such as distributed or embedded generation).

In some circumstances demand management can provide efficient alternatives to network augmentations to relieve constraints. This can have positive economic impacts through encouraging the efficient use of network assets or reducing inefficient energy use or inefficient peaks, resulting in lower prices for consumers and external benefits for the environment or market.

2.2 Requirements of the NER

The transitional Rules will confer discretion on the AER to develop and publish an incentive scheme or schemes to provide incentives for DNSPs to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way. Such a scheme is referred to in this paper as a ‘demand management incentive scheme’.

If the AER publishes a demand management incentive scheme it must set out the way in which the scheme will operate for the next distribution determination. The scheme must be published by 1 March 2008; otherwise it cannot be applied to DNSPs for the next regulatory period.

In developing and implementing a demand management incentive scheme, the AER must have regard to the following factors that will be set out in the transitional rules:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs
- the effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a DNSP’s incentives to adopt or implement efficient non-network alternatives
- the extent the DNSP is able to offer efficient pricing structures
- the possible interaction between a demand management incentive scheme and other incentive schemes
- the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.

In considering the role of a demand management incentive scheme, the transitional Rules will require the AER to have regard to the extent to which the DNSP has considered and made provision for efficient non-network alternatives in its consideration of the forecast of required capital expenditure (capex) that is included in a building block proposal.

2.3 Current position in ACT and NSW

2.3.1 ACT

The ICRC does not currently apply a specific financial incentive to encourage ActewAGL to pursue demand management activities in the ACT. ActewAGL is regulated under an average revenue cap form of regulation. This creates incentives for distributors to attempt to lower the demand for electricity without a cost to revenues.

In its 2003 draft determination, the ICRC noted that price is the main tool for ActewAGL to manage demand and promote efficient network utilisation. The ICRC acknowledged ActewAGL's existing demand management initiatives, including detailing greenhouse gas effects on customers' bills and the Greenpower initiative. It stated that its regulatory determination would maintain ActewAGL's incentives to continue its demand and load management programs.

In its final decision, the ICRC noted a submission suggesting that a demand management fund should be introduced in the ACT. It concluded, however, that linking a demand management fund to the distribution charge may not be appropriate, given that the ACT has a relatively small industrial base and relatively large residential base. The ICRC further noted that ActewAGL's existing Greenpower initiative was, to a limited extent, based on the demand management fund principle.

While not providing a formal demand management incentive, the ICRC's final decision did encourage ActewAGL to further develop its demand management policies and tariff arrangements for embedded generators, and to develop demand management and demand reduction education programs across its water, electricity and gas businesses. [7]

2.3.2 NSW

2.3.2.1 IPART determination

In June 2004, IPART introduced the D-factor, a demand management incentive scheme, into the *NSW Electricity Distribution Pricing 2004–05 to 2008–09: Final Determination* (IPART's pricing determination). The D-factor applies to EnergyAustralia, Integral Energy and Country Energy in the current regulatory control period.

In applying the D-factor IPART aimed to reduce regulatory barriers to demand management in NSW. In particular, it sought to overcome the barriers created under the weighted average price cap (WAPC) form of regulation applying in NSW. This form of regulation provides DNSPs with incentives to achieve demand forecasts in order to reach a required revenue allowance, indirectly providing DNSPs with disincentives to undertake demand management.

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[7] ICRC, Final decision: Investigation into prices for electricity distribution services in the ACT. March 2004. p.110

The D-factor arose out of IPART's inquiry into demand management in 2002, which found that demand management can be more cost-effective in relieving network constraints than network augmentation, can improve capital efficiency and benefit end-users through lower costs. [8]

IPART saw the D-factor as a short-term incentive for businesses to overcome barriers to the greater use of demand management solutions in supplying network services. These barriers were the introduction of the WAPC and limitations of the emergent market of demand management solutions.[9] IPART also had concerns regarding rising peak loads and network asset underutilisation in NSW. IPART expected that demand management, and its related costs, would become part of the standard business practices of DNSPs so that, in the medium to long term, a special D-factor incentive would not be necessary.

The D-factor mechanism

The D-factor allows NSW DNSPs to recover the costs of implementing approved tariff and non-tariff based demand management measures through an increase in the WAPC. It also allows DNSPs to recover any foregone revenue from approved non-tariff demand management measures. That is, the D-factor allows slightly higher prices to encourage NSW DNSPs to find more efficient ways to meet peak electricity demand from consumers.

IPART has recently released an information paper on the D-factor, *NSW Electricity Information Paper No 2/2007 - Demand Management in the 2004 distribution review: progress to date*.[10] The information paper outlines the D-factor mechanism and its results to date in NSW.

The paper shows that the D-factor has had a small impact on network decisions and prices since its implementation.[11] Between 2004–05 and 2005–06 the NSW DNSPs spent around $8.26 million on demand management programs as a result of the D-factor scheme. Table 1 shows the details of spending by each DNSP.

The total avoided capital and operational costs through approved demand management activities between 2004–05 and 2005–06 was approximately $24.4 million. The deferral times varied for DNSPs depending on the type of project to be implemented.

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8 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services – Issues Paper*, July 2001.

9 IPART, *NSW Electricity Distribution Pricing 2004-05 to 2008-09 - Final Report,* June 2004, p 89.

10 Available at www.ipart.nsw.gov.au.

11 IPART, *NSW Electricity Information Paper No 2/2007 - Demand Management in the 2004 distribution review: progress to date*, 2007, p. 5.

Table 1 Demand management implementation costs and D-factor results

DNSP	2004–05		2005–06	
	Cost of DM ($)	Rounded D-factor (%)		Cost of DM ($)
EnergyAustralia	3,592,004	0.005	**EnergyAustralia**	3,592,004
Integral	460,492	0.001	**Integral**	460,492
Country Energy	None	None	**Country Energy**	None

*Integral Energy received a raw D-factor of 0.00129. However, the change in expenditure between 2004/05 and 2005/06 was less than the D-factor materiality threshold for adjustment or deferral.

**Country Energy received a raw D-factor of 0.0003. The determination allows this result to be deferred to the 2008/09 financial year.

2.3.2.2 Other regulatory instruments in NSW

The NSW *Electricity Supply Act 1995* requires DNSPs to investigate and report on demand management strategies when it reasonably expects 'that it would be cost-effective to avoid or postpone the expansion [of a distribution system] by implementing such strategies.'[12]

The NSW Demand Management Code of Practice (The DM Code) provides guidance to DNSPs in meeting the requirements of the *Electricity Supply Act*. The DM Code is part of the wider regulatory framework of DNSPs in NSW, working alongside any schemes put in place by IPART and, in future, by the AER under the new national governance arrangements.

2.4 Demand management incentives in other States

2.4.1 ESCOSA determination

South Australia has the highest peaking load in the country. The Essential Services Commission of South Australia (ESCOSA) considered demand management in the *2005–10 Electricity Distribution Price Review – Part A: Statement of Reasons*.[13] As in the ACT, South Australia has an average revenue cap form of regulation. This creates incentives for distributors to lower the demand for electricity, as this will allow them to suitably adjust prices and maintain revenue despite lowering energy usage.

12 Electricity Supply Act 1995 (NSW). Schedule 2, subsection 6(5).

13 ESCOSA's final decision on this matter is outlined in Chapter 4 of its decision, available at http://www.escosa.sa.gov.au.

ESCOSA approached demand management as a way to reduce capital expenditure at locations where network constraints are forecast.

ESCOSA has provided an allowance of $20 million for a range of pilot demand management initiatives over the 2005–10 regulatory control period.[14] This allowance is categorised as operating expenditure (opex), and is not included in demand forecasts, capital expenditure forecasts or the regulatory asset base.[15] This classification of the scheme was due to its 'pilot nature'.[16]

ESCOSA's demand management framework was based on a cost-benefit analysis undertaken by Charles River Associates Consultancy. This compared potential demand management programs to a roll-out of interval metering. The report outlined power factor correction, standby generation, residential direct load control and aggregation as potentially applicable demand management for the South Australian market.[17]

Under its licence, ETSA Utilities is required to work closely with ESCOSA on the demand management program with specific reporting requirements for each initiative.[18] The programs undertaken by ETSA Utilities are determined by a Steering Committee which selects projects on merit and network benefits within the 2005–2010 regulatory control period.[19]

2.4.2 ESC (Vic) determination

Victoria currently has Australia's second highest peak load (in percentage terms). The Essential Services Commission (ESC) of Victoria considered demand management in the *Electricity Distribution Price Review 2006-10.*

The form of regulation in Victoria is a weighted average price cap, which, as in NSW, has the effect of deterring DNSPs from using tariffs to reduce demand on constrained networks.

The ESC has applied a simple demand management framework to encourage DNSPs to recover all demand management implementation costs out of the cost savings arising from capital expenditure deferral.[20] It also provided $600 000 in each DNSP's opex budget to investigate or implement demand management programs in the

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14 ESCOSA *2005-2010 Electricity Distribution Price Determination Part A: Statement of Reasons* April 2005, pp. 53 and 60.

15 Ibid. pp. 53 and 60.

16 Ibid. p. 54.

17 CRA, *Assessment of Demand Management and Metering Strategy Options* August 2004 pp.76-83.

18 ESCOSA, Demand Management and the Electricity Distribution Network – Draft Decision September 2004 pp. 27-28.

19 ESCOSA, *ETSA Utilities demand management program – Progress Report*, June 2007, p. 9.

20 ESC, *Electricity Distribution Price Review 2006-10 Final Decision* October 2006, p.495.

regulatory period. This amount was designed to offset the disincentives to use demand management across regulatory periods.[21]

The ESC also considered implementing a trial period in which, upon ESC approval, demand management initiatives may be excluded from the service incentive scheme, or S-factor.[22]

The ESC's demand management policy approach was supplemented by a large mandatory Interval Metering Rollout (IMRO) proposed to begin in 2006.[23] This was expected to improve the information available to DNSPs. The ESC considered that it should allow efficient non-network solutions to be more easily identified by DNSPs, and should also allow consumers of electricity to better respond to improved price signals.[24]

The ESC did not apply a D-factor, as it considered IPART's approach of providing 'relatively generous incentives with positive revenue outcomes for distributors', would generate higher consumer prices that were inappropriate for Victorian consumers.[25] The ESC viewed distribution tariffs as a more effective and efficient method to manage rising demand, and sees this as a future result of the IMRO.[26]

2.5 Summary of initial consultation

2.5.1 DNSP Views

Initial consultation with NSW DNSPs has shown that there is a general desire to continue the D-factor incentive into the next regulatory control period in NSW. Some feedback the AER received included:

- The D-factor has had a limited implementation time, particularly since it has to be incorporated into planning processes. A longer implementation time would be useful.
- The D-factor has encouraged demand management activity by NSW DNSPs beyond that which would have occurred without the D-factor.
- The capacity of NSW DNSPs to implement demand management depends on the nature of their customer base and networks.

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21 The benefit for the DNSPs of demand management may not be felt in the same regulatory period in which the demand management policies are rolled out, creating a disincentive to undertake demand management. The allowance was implemented as a balance for the disincentive for demand management created by the potential for demand management to be realised across multiple regulatory periods.

22 Ibid, p. 498.

23 Ibid, p. 509.

24 AER staff consider that the benefits of interval metering to DNSPs are in improving its basic network information, anecdotal evidence provided by Charles River Associates indicates that there is a limited relationship between smart meters and increased demand management programs.

25 Ibid, p. 500.

26 Ibid, p. 500.

- Experience in demand management has reduced the risks and uncertainties surrounding the costs and impact of demand management compared to network augmentation.
- The D-factor is necessary due to disincentives caused by a WAPC form of regulation (whereby a NSW DNSP has an incentive towards higher (rather than lower) demand volumes).
- There is an increasing willingness from management of some DNSPs to undertake demand management, leading to its better integration into planning processes than before the D-factor was introduced.
- The D-factor complements the NSW DM Code, by providing incentives to implement strategies the code requires NSW DNSPs to investigate.
- A scheme that provides incentives for broad based demand management would be viewed favourably by NSW DNSPs.

2.5.2 Consumer Views

Overall, those consumer advocacy groups initially consulted see net benefit for consumers in the long term of continuing the D-factor scheme. The consumer groups stated that it acts as an efficient mechanism, leading to long-term price reductions for consumers and is a positive way of providing incentives to DNSPs to undertake demand management.

In summary, the feedback the AER received included:

- Tariff based incentives are limited in effectiveness as retailers may not pass price signals on to customers and residential consumers’ demand is price inelastic.
- Large end users of electricity are more responsive to price, and likely to be willing to pay for efficiency gains.
- The D-factor is a good mechanism for giving DNSPs incentives to conduct demand management projects with larger customers.
- There is scope for more education of consumers to assist their awareness of the benefits of demand management.
- A learning-by-doing fund, similar to the SA model, may not result in certain long-term efficiency gains that benefit consumers.

2.6 Options for developing a scheme for the 2009-2014 determination

The objective of the national electricity market regulation is:

> to promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system.[27]

[27] Section 7 of the National Electricity Law

The AER is considering the development of a demand management incentive scheme within this policy context along with the factors for its consideration that will be prescribed in the transitional Rules (see paragraph 2.2 of this chapter).

The AER also notes that the Australian Energy Market Commission (AEMC) is conducting a review under section 45 of the Nation Electricity Law to investigate the role of demand side participation in achieving the National Electricity Market (NEM) objective and to ensure the full and efficient participation of the demand side in the NEM. The AEMC intends to publish a Statement of Approach paper before the end of 2007 to provide further detail of the AEMC's intended approach to the review.

2.6.1 Options for consideration

The AER is considering a range of options regarding the form of any demand management incentive scheme to be applied to NSW and the ACT. However, the AER has chosen to limit the possible options to account for the short timeframes available to develop and implement a scheme in time for the NSW and ACT distribution reviews for the next regulatory control period.

The options for implementing a scheme in NSW include:

- Discontinue the D-factor and any demand management incentives
- Continue the D-factor in its present form
- Continue the D-factor in a modified form
- Supplement or replace the D-factor with another existing demand management model, such as a learning-by-doing fund.

Further, the options for implementing a scheme in the ACT include:

- Introduce the same D-factor scheme as applied in NSW
- Introduce a scheme based on an existing demand management model, such as a learning-by-doing fund
- Not introduce a scheme

2.7 Initial position

2.7.1 NSW

The AER considers that the D-factor provides a practical starting point from which to consider the development of a demand management incentive scheme in NSW. Based on its initial consultations, the AER has found a reasonably high level of stakeholder support for the continuation of the D-factor. While IPART's paper on the D-factor outcomes suggests to date that the results have been modest, the AER considers there are positive reasons for the continuation of the D-factor. These include:

- *Form of regulation* — in accordance with the transitional Rules, the AER will apply a weighted average price cap form of control for standard control services. Some stakeholders consider a price cap to be a disincentive to undertake demand management. The AER sees a benefit in addressing these regulatory barriers to demand management incentives.

- *Capacity building and future opportunities* — in spite of its short period of implementation, the results of the D-factor to date have demonstrated the ability of NSW DNSPs to build capacity and experience in their planning processes and the emergent demand management market. The AER considers that there are further opportunities for efficiency gains through planning processes and informed project assessments resulting from the D-factor.
- *Information and data collection effects* — given the short period in which the NSW DNSPs have had to implement demand management under the D-factor incentive scheme, the AER is of the view that its continuation would provide additional data on the impact of the incentive. Further, it is likely to provide a robust data set to help forecast potential capex efficiencies from demand management programs.
- *Limitations on price signals* — the AER's initial consultation with stakeholders indicates that there are limitations for the distributors to send signals to the market about constraints on the network through price. An alternative mechanism to effectively reduce constraints on the network is therefore required. The D-factor appears to be the preferred alternative mechanism at this time.
- *Customer willingness to pay* — preliminary indications from stakeholders is that the scheme has resulted in modest net benefits.

In this initial phase of consultation, the AER has also considered the option of implementing a learning-by-doing fund alongside the D-factor incentive. Such a scheme could potentially provide DNSPs with incentives for more broad based demand management programs to improve efficient electricity use across the market.

The AER considers that further stakeholder views on the form, focus and potential strength of incentives would be required to help it to assess the potential application of a learning-by-doing fund within the NSW. In considering these views, the AER would take into account the complexity and time available for implementing any further incentives.

2.7.2 ACT

Based on its initial consultations and analysis to date, the AER does not presently consider that it would be appropriate to implement a D-factor incentive scheme in the ACT for the next regulatory period. As outlined below, this is due to the form of regulation applied in the ACT, the nature of the ACT network and some stakeholder views that ActewAGL has scope to provide efficient pricing structures:

- *Form of regulation* — unlike NSW, ActewAGL will continue to be regulated under an average revenue cap. In its past regulatory decisions, the ICRC stated that sufficient incentives exist for ActewAGL to seek out cost savings through activities like demand management. In the absence of evidence to the contrary, the AER considers that the same incentives exist for ActewAGL and, therefore, no additional incentives for demand management are required in the next regulatory period.
- *Network characteristics* — the network in the ACT is characterised by many residential customers and few commercial loads. Demand management opportunities are more likely to be pursued at high cost, low volume customer categories, for example, residential customers. In theory, the average revenue cap

provides an incentive for the DNSP to avoid demand management at the high volume, high density end of the market where it can supply more electricity through its network at a relatively lower cost.

- *Ability to communicate price signals* — some stakeholders consider that ActewAGL has scope for providing efficient pricing structures to the market. This would mean that there is less necessity to implement an alternative mechanism, as the market mechanism can achieve a more efficient demand management outcome. However, a potential barrier to the effectiveness of ActweAGL's price signalling could arise if retailers do not pass on the efficiency cost savings to end-users.

While the AER does not consider a D-factor to be an appropriate model of incentive to apply in the ACT, it proposes to further consider the appropriateness of a learning-by-doing fund to encourage demand management in the ACT. The AER seeks stakeholder views on the form, focus and potential effectiveness of incentives which would be required to help it to assess the potential application of a learning-by-doing fund within the ACT.

2.8 Request for submissions

The AER seeks submissions from stakeholders about considering a demand management incentive scheme for DNSPs in NSW and the ACT for the regulatory control period 2009–2014.

Submissions are sought on the following issues:

1. The scope, and related incentives and disincentives, for DNSPs in NSW and ACT to contribute towards efficient demand management
2. The role and effectiveness of the D-factor scheme in achieving its aims and objectives in the current regulatory period in NSW and
3. The structure of a potential demand management scheme for DNSPs in NSW and/or the ACT, the costs and benefits of this scheme and the expected impact on the efficiency of the National Electricity Market.

In approaching these issues, submissions should consider the following options which the AER is considering:

- The options for implementing a scheme in NSW include:
    - discontinue the D-factor and any demand management incentives,
    - continue the D-factor in its present form,
    - continue the D-factor in a modified form,
    - supplement or replace the D-factor with another existing demand management model, such as, a learning-by-doing fund.
- The options for implementing a scheme in the ACT include:
    - introduce the same D-factor scheme as applied in NSW,

- introduce a scheme based on an existing demand management model, such as, a learning-by-doing fund
- do not introduce a scheme.

In considering these options, submissions should address the following factors which the AER must take into account when developing a demand management incentive scheme:

- the need to ensure that benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for DNSPs;
- the effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a DNSP’s incentives to adopt or implement efficient non-network alternatives;
- the extent the DNSP is able to offer efficient pricing structures;
- the possible interaction between a demand management incentive scheme and other incentive schemes; and
- the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.

Submissions may also address the likely magnitude of the administrative costs of modifying current practices.

3 Control mechanism for alternative control services

3.1 Introduction

The amended NER will provide for distribution services to be classified according to the form of regulation applied to those services. There will be two types of regulated services:

- Direct control services
- Negotiated services

Direct control services will be sub-classified as standard control services and alternative control services. Standard control services must be regulated using a building block calculation, however, alternative control services may, but need not be regulated using a building block calculation.

This chapter discusses issues associated with determining the manner in which alternative control services will be regulated in the ACT and NSW. The services that will be classified as alternative control, and accordingly to which this chapter is relevant are:

- ACT - the provision of and servicing of meters for customers consuming fewer than 160 megawatt hours per annum (types 5-7 meters), including:
    - meter testing
    - meter reading
    - meter checking
    - the processing of metering data
    - the provision of non-standard meters
- NSW - construction and maintenance of public lighting infrastructure by DNSPs in NSW.

3.2 Requirements of the NER

The transitional arrangements will require the AER to publish a statement outlining its likely approach to the control mechanism for alternative control services. The statement is not binding, however, if the AER's distribution determination is not in accordance with the statement, the AER will be required to state its reasons for its departure.

3.2.1 Deciding on a control mechanism

The transitional Rules will provide that the control mechanism for alternative control services may consist of:

- a schedule of fixed prices
- caps on the prices of individual services
- caps on the revenue to be derived from a particular combination of services

- tariff basket price control
- revenue yield control
- a combination of any of the above.

The transitional Rules will specify factors to which the AER must have regard in deciding on a control mechanism:

- the potential for development of competition in the relevant market and how the control mechanism might influence that potential
- the possible effects of the control mechanism on administrative costs of the AER, the DNSP and users or potential users
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)
- any other relevant factor.

3.2.2 Annual pricing approvals

The transitional Rules will require DNSPs to submit pricing proposals to the AER on an annual basis that include proposed tariffs and tariff classes for alternative control services. The expected weighted average revenue for each tariff class must comply with prescribed pricing principles. The AER will be required to approve annual pricing proposals, or make necessary amendments if proposals are deficient.

3.3 Current control mechanisms in the ACT and NSW

3.3.1 ICRC determination

Excluded services in the ACT are subject to a total revenue cap which is escalated annually by CPI.

3.3.2 IPART determination

Rule 2004/1 – Regulation of Excluded Distribution Services of IPART's determination (the Excluded Services Rule) outlines the regulatory framework applied to the construction and maintenance of public lighting infrastructure in the current regulatory control period.

Under IPART's regulatory framework, DNSPs have been required to comply with prescribed pricing principles in setting prices for the construction and maintenance of public lighting infrastructure. These principles require that:

- Prices are to signal the economic costs of service provision by being subsidy free (this requires them to be between incremental and stand alone costs).
- The underlying service classifications, cost data, cost allocations and other elements that contribute to the prices charged by the DNSP should be periodically reviewed and updated where relevant to reflect industry developments and

changes in user requirements and preferences, methods of service provision and costs.

- DNSP must also consider the impact of the price change on customers.

Two months prior to any price changes, DNSPs must submit a public lighting report to IPART outlining the proposed price changes, the costs of providing the services, the service standards supporting those costs, and an assessment of the impact of the changes on customers.

IPART assesses the proposed changes against the pricing principles and whether the DNSP has considered the impacts on customers. If IPART is not satisfied it will require the DNSP to submit an alternative proposal. Any price change information and new prices must be made available to customers one month before the new prices become effective.

3.3.2.1 Other regulatory arrangements - NSW Public Lighting Code

In addition to the application of the Excluded Services Rule to public lighting services in NSW, the NSW Department of Energy, Utilities and Sustainability (now the NSW Department of Water of Energy) released the NSW Public Lighting Code on 1 January 2006. This is a voluntary code outlining, among other things, minimum maintenance standards and associated service level guarantees, and minimum requirements for inventories.

The AER understands that the Department of Water of Energy is currently reviewing the NSW Public Lighting Code, with a view to determining its effectiveness and whether any amendments are necessary.

3.4 Application of the current mechanisms

3.4.1 ACT

At the 2004 determination, ActewAGL proposed a revenue requirement from metering services of $5.09 million for the first year of the regulatory period. The ICRC assessed this proposal based on the rolled-forward value of the excluded assets and analysis of the build-up of costs associated with providing the excluded services. The ICRC accepted ActewAGL’s proposed revenue requirement, concluding it did not represent an excessive return. The current determination allows for the revenue requirement for metering services to be escalated annually by CPI, using the following approach:

$$\text{Maximum allowed revenue}_t = \left(1 + \left(CPI_t\right)\right) \times \left(\text{MAR}_{t-1}\right)$$

Where:

- MAR_{t-1} is the maximum average revenue allowance for the previous year
- CPI is the Consumer Price Index

The CPI value used for escalating the MAR each year is determined using the following formula:

$$CPI_t = \frac{\left(CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{September(t-1)} + CPI_{December(t-1)}\right)}{\left(CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{September(t-2)} + CPI_{December(t-2)}\right)} - 1$$

3.4.2 NSW

Discussions with the NSW DNSPs have indicated that the Excluded Services Rule has been implemented slightly differently by each NSW DNSP.

3.4.2.1 Country Energy

Country Energy submitted its most recent public lighting pricing application to IPART in April 2007. It determined the costs of providing public lighting services through a building block approach. This approach provides for the operating and maintenance costs, as well as a return on and return of the capital costs of public lighting assets within Country Energy's network. Country Energy has determined the capital costs of its assets using the depreciated replacement cost, based on the weighted average age of assets the standard lives of each asset class, and applying a 7 per cent real return on these assets, consistent with the return allowed for its prescribed services.

Country Energy stated in its application that it is still transitioning to cost reflective prices for public lighting. It proposed to increase prices by a weighted average nominal rate of 5.22 per cent. Country Energy sought to reflect economic costs and subsidy-free prices by limiting tariffs to the economic cost of the service. Country Energy also applied a tariff basket limit or side constraint for each customer bill of CPI plus 4.5 per cent. IPART approved Country Energy's application in June 2007.

3.4.2.2 EnergyAustralia

EnergyAustralia submitted its primary public lighting pricing proposal to IPART in June 2005. In this proposal EnergyAustralia stated that existing EnergyAustralia tariffs were not cost reflective, resulting in a revenue shortfall. To rectify the revenue shortfall, EnergyAustralia proposed a series of phased revenue increases, taking a revenue cap form, over the 2004–09 regulatory control period.

In response to EnergyAustralia's application, IPART allowed a revenue path increasing by 10 per cent in 2005–06 followed by 5 per cent increases thereafter. Side constraints were also applied to EnergyAustralia's public lighting prices. These took the form of a tariff basket constraint in which individual customer bills were not allowed to increase by more than 7.9 per cent for each of the financial years 200 – 2008 to limit the customer impact.

While EnergyAustralia sought to reflect the economic cost of providing services, the application aimed to provide sufficient revenue in the short term to meet costs. Some non-cost reflective prices were allowed to persist to ensure appropriate revenue outcomes for EnergyAustralia in the long term.

3.4.2.3 Integral Energy

Integral Energy submitted its most recent public lighting pricing application to IPART in June 2007. It determined the costs of providing public lighting services through a building block approach. This approach provides for the operating and maintenance costs, as well as a return on and return of the capital costs of public lighting assets within Integral Energy's network. Integral Energy has determined the capital costs of its assets using the depreciated replacement cost, based on the weighted average age of assets the standard lives of each asset class, and applying a 7 per cent real return on these assets, consistent with the return allowed for its prescribed services.

Integral Energy states that it is still transitioning to cost reflective prices for public lighting. It proposed to increase prices by CPI plus 2 per cent. Integral Energy foreshadowed further real price increases to move the prices toward cost reflectivity.

The AER understands that IPART's review of Integral's most recent public lighting pricing application has not yet been concluded.

3.5 Issues for the 2009-2014 determination

3.5.1 ACT

In the 2004 decision the ICRC indicated that the form of control applied to ActewAGL's metering services may be reviewed should market conditions change. The ICRC stated:

> The commission considers it appropriate to regulate excluded services using maximum allowable revenues until such time as contestability in a competitive market occurs. Setting a maximum revenue cap will ensure that ActewAGL is able to recover all the costs associated with providing metering services and will provide the opportunity for competitors to enter the market at lower prices at the conclusion of the metering derogation. [28]

In June 2005, the ACCC extended a jurisdictional derogation under the National Electricity Code for the ACT, granting exclusivity for the provision of services for meter types 5-7 to ActewAGL. This derogation expired on 31 December 2006. The new NER has adopted this previous jurisdictional derogation, deeming the market for types 5-7 metering services to be non-contestable, and the ACT local network service provider – ActewAGL - to be the responsible person for these services.

3.5.1.1 Factors to which the AER must have regard

- Potential for the development of competition and how the control mechanism might influence that potential – as noted above, the market for metering services for types 5-7 meters is non-contestable and accordingly there is no potential for the development of competition at this time. Therefore, the control mechanism will not affect the development of competition.
- Administrative costs – the administrative costs will largely depend on the manner in which the mechanism is implemented. For example, a building block analysis may be undertaken for any of the control mechanisms, which may impose higher costs than an alternative approach of simply escalating current revenues. The extent of these costs will depend on the methodology underlying the building block analysis or escalation of revenues.

[28] ICRC, *Final decision: Investigation into prices for electricity distribution services in the ACT.* March 2004. p.17-18

- Current regulatory arrangements – unless there are sound reasons for departing from the current approach, the AER will consider continuing the current revenue approach to regulating metering services.
- Desirability of consistency between regulatory arrangements for similar services – the AER understands that the current regulatory arrangements for metering services across the NEM vary significantly, and accordingly there is no general framework with which to compare the arrangements in the ACT. The AER notes that is the first decision the AER will make regarding the control mechanism to apply to distribution services. It is possible that future decisions will amend current regulatory arrangements, and accordingly in the future this factor may provide more guidance if consistency across the NEM emerges than at this time.

In light of these considerations, the AER intends to consider continuing the existing form applied in the ACT.

Under such an approach ActewAGL would propose a revenue cap based on a limited building block analysis, with maximum allowable revenues to be escalated each year by CPI. Consistent with the approach taken in the current regulatory period, the revenue cap would be established based on the rolled-forward value of the relevant metering assets, and analysis of the build-up of costs associated with providing the services. ActewAGL's revenue cap proposal for these services would need to include some detail on the build-up of costs. In assessing the build-up of costs the AER would have regard to whether the proposed costs are efficient, and would allow a return on capital equal to that allowed for standard control services.

3.5.2 NSW

3.5.2.1 Factors to which the AER must have regard

- Potential for the development of competition and how the control mechanism might influence that potential – the AER understands that there is limited potential for competition in the market for public lighting services. While there is competition for the construction of new public lighting assets, maintenance services for existing infrastructure are not subject to competition.
- Administrative costs – the administrative costs will largely depend on the manner in which the mechanism is implemented. For example, a building block analysis may be undertaken for any of the mechanisms, which may impose higher costs than an alternative approach of simply escalating current revenues and/or prices. The extent of these costs will depend on the methodology underlying the building block analysis or escalation of revenues and/or prices.
- Current regulatory arrangements – it appears that the current regulatory arrangements are not consistent with the requirements of the transitional Rules. Hoover, the practical application of those arrangements may be broadly consistent with the transitional Rules in some cases. This issue is discussed further below.
- Desirability of consistency between regulatory arrangements for similar services – the AER has not formed a view as to whether consistency between regulatory arrangements for other public lighting services across the NEM is desirable. However, in view of the limited time available to provide guidance on the AER's likely approach to determining a control mechanism, it may not be possible to seek to align the approach in NSW with that in other jurisdictions.

3.5.2.2 Are the current arrangements consistent with the transitional Rules?

The transitional Rules will require the AER to have regard to the current regulatory arrangements applying to public lighting services. The AER will consider continuing these arrangements if they are consistent with the control mechanisms from which the AER may select in the transitional Rules. The following aspects appear relevant to this consideration:

- Pricing approvals – the Excluded Services Rule provides for price changes on an ad hoc basis (subject to compliance with information disclosure requirements including the provision of cost information to IPART). The transitional Rules will require annual pricing approvals by the AER. The pricing principles with which DNSPs must comply in setting prices differ under the Excluded Services Rule and the transitional Rules.
- The Excluded Services Rule does not explicitly impose controls over the revenues or prices to be earned from public lighting services, whereas the transitional Rules will require a control mechanism that does so.
- The Excluded Services Rule appears to set a broad framework for the control of revenues or prices to be earned from public lighting services, with some flexibility to decide on the precise mechanism during the period. The transitional Rules, however, will require the AER to make a decision on the control mechanism as part of its distribution determination.

It appears that the form of the Excluded Services Rule may be inconsistent with the requirements of the transitional Rules. However, if stakeholders can demonstrate that the manner in which the Excluded Services Rule has been implemented is consistent with the requirements of the transitional Rules, the AER will consider whether existing arrangements can be continued, subject to such changes as are necessary to comply with the transitional Rules.

3.5.2.3 Are the current arrangements desirable?

The AER has commenced discussions with some stakeholders in NSW in order to assist it in understanding the current environment within which public lighting is regulated. Stakeholders have raised a number of issues associated with the application of the current control mechanism in NSW. These issues include:

- Service quality – some Councils have expressed dissatisfaction with the service levels that have been provided in the current regulatory period.
- Actual levels of capital expenditure and operating expenditure – it has been suggested that the level of investment in capital by some DNSPs has been lower than that provided for by IPART. It has also been suggested that the level of operating expenditure has been inappropriately low, resulting in poor service levels.
- Administrative costs - DNSPs have suggested that the administrative costs of complying with the Excluded Services Rule are high. It is suggested that maintaining and compiling information on the costs of providing public lighting services is an onerous task given the number of the assets.

- Costs of providing the services
    - some Councils have expressed concern at the lack of transparency in determining the costs of providing the services, and the limited ability of the Councils to participate in the process
    - DNSPs have suggested that the increase in costs has been higher than the increase in allowed revenues, with the result that revenues are not sufficient to cover costs.

It may be possible to address some of these issues by modifying existing arrangements, rather than introducing an entirely new control mechanism. One option would be to simply escalate current revenues or prices. This would only be an appropriate option if the AER could be satisfied that current revenues or prices are efficient. An alternative is to undertake a building block assessment.

3.5.2.4 Approach to determining efficient costs

While not required under the transitional Rules, a building block assessment provides a firm basis for estimating the efficient costs of providing services. Given that the administrative costs of a building block assessment can be high, the AER is interested in considering a limited analysis along the following lines:

- Establishing the regulatory asset bases – the AER is interested in exploring whether it is possible to roll forward existing asset bases maintained by the DNSPs. This may depend on the level of detail of information regarding assets that is maintained by the DNSPs. If it is not possible to roll forward the exiting asset bases, establishing a new asset base may be necessary. Given that the administrative costs of a valuation of the asset base may be high, and there is limited time available in which to undertake such an assessment, it may be appropriate to apply a simplified approach to determining an asset base for each DNSP.
- Determining efficient capex and opex – DNSPs could submit capital and operating expenditure proposals to the AER either as part of or in addition to the capital and operating expenditure proposals for standard control services. Rather than applying the criteria and factors that must be applied in assessing proposals for standard control services, the AER could assess the expenditure proposals for public lighting against whether they represent the efficient costs of providing those services. The AER could assess efficiency against achieving the service levels contemplated by the Public Lighting Code.
- Return on capital – the weighted average cost of capital that is applied to standard control services could be applied to determine a return on capital for alternative control services.

Upon determining the efficient costs of providing the services, the AER considers it would be appropriate to determine an appropriate price or revenue path for the period.

In undertaking a building block analysis, the AER would seek to promote transparency by seeking public comment on the proposals put forward by the DNSPs.

3.6 Request for submissions

The AER seeks submissions on the following issues:

ACT

1. Should the AER apply a total revenue cap to alternative control services in the ACT? If so, are any modifications to the total revenue cap as applied by the ICRC appropriate?

2. In determining a revenue allowance for the next regulatory control period, should the AER:

    a. escalate current allowances, or

    b. undertake a building block analysis?

3. If a building block analysis is undertaken, should the AER adopt the approach to the building block analysis outlined in section 3.4.1?

Submissions may also address the likely magnitude of the administrative costs of modifying current practices.

NSW

1. Would continuation of the Excluded Services Rule meet the requirements of the transitional Rules to determine a control mechanism consisting of:

    - a schedule of fixed prices
    - caps on the prices of individual services
    - caps on the revenue to be derived from a particular combination of services
    - tariff basket price control
    - revenue yield control
    - a combination of any of the above?

    If not, what modifications to the Excluded Services Rule could be made to meet the requirements of the transitional Rules?

2. Should the current mechanisms applied to each DNSP to control revenue and/or prices be maintained?

3. In determining allowances for the next regulatory control period, should the AER:

    a. escalate current allowances, or

    b. undertake a building block analysis?

4. If a building block analysis is undertaken:

a. should the AER adopt the approach to the building block analysis outlined in section 3.5.2.4?

b. what approach should the AER take to determining the asset bases for public lighting assets for each DNSP in NSW?

Submissions may also address the likely magnitude of the administrative costs of modifying current practices.

4 Guideline on determining materiality for pass through events

4.1 Introduction

The transitional Rules will provide that a pass through event that has a material impact on the costs of providing direct control services may, subject to the AER's approval, be passed through to consumers. This chapter discusses issues associated with determining what will constitute a material impact on costs.

4.2 Requirements of the NER

The transitional Rules will allow a distribution determination to be amended to account for the costs of specified events that have not been accounted for in the determination. Such an event is referred to in the transitional Rules as a pass through event. The transitional Rules will require that there is certainty as to which events may constitute pass through events before the regulatory control period commences; the costs of an event may not be passed through unless the event is specified as a pass through event in the NER or by the AER in its distribution determination.

An example of a pass through event may be a change in licence conditions. DNSPs may be aware that a change in licence conditions during the regulatory control period is likely, however, DNSPs may be unable to forecast the cost of this change until it occurs. If not defined in the NER, the AER may specify in its distribution determination that this change will constitute a pass through event, and upon its occurrence, the AER may approve a pass through of the costs of the event.

An event will only constitute a pass through event if the costs of the event will have a material impact on costs. Therefore, in determining whether the costs of an event should be passed through, the AER must consider the materiality of the costs.

The transitional Rules will provide that the AER may publish a guideline as to the AER's likely approach to determining materiality in the context of possible pass through events. The guideline is not binding, however, if the AER's distribution determination is not in accordance with the guideline, the AER will be required to state its reasons for departing from the guideline.

4.3 Current positions

4.3.1 Current ICRC determination

The ICRC determination adopted a materiality threshold of $1 million in opex in any one year. The determination provides for a total annual revenue requirement of approximately $90-$105 million over the regulatory period for prescribed electricity services. For the purposes of ActewAGL, an amount of $1 million in opex is approximately 1 per cent of ActewAGL's revenue in a year. The ICRC considered this an appropriate materiality threshold because it is an appropriate point at which 'risks can be transferred from the business to customers'.[29]

The ICRC's threshold for capex involved considering the revenue impact of capex, but basing the threshold on the annual costs of the event. The ICRC noted:

> The equivalent capital expenditure amount is approximately $7.5 million, which equates to approximately $1 million in annualised terms (using a 6.9 per cent return and an assumed asset life of fifteen years).[30]

4.3.2 Current IPART determination

IPART defined a materiality threshold equivalent to 1 per cent of average annual smoothed revenue requirements over the regulatory period per event, as set out below:

> The Tribunal has decided to define a materiality threshold equivalent to 1 per cent of average annual smoothed revenue requirements over the regulatory period per event. That is, the Tribunal will only pass through events for which the average annual impact on cost as a result of the event is equivalent to 1 per cent of the average annual smoothed revenue requirements (as laid out in the Tribunal's determination). [31]

IPART's decision explained the definition of the average annual change in costs:

> **2.2 "Materially" in the general cost pass through definition**
>
> … an event results in a DNSP incurring **Materially** higher or **Materially** lower costs if the annual average change in costs in respect of that event exceeds 1% of the average annual smoothed revenue requirement for the DNSP as set out in Annexure 12. For this purpose, the average annual change in costs in respect of an event is calculated as follows:
>
> (a) in the case of a Positive Change Event for that DNSP, the Approved Pass Through Amount in respect of that Positive Change Event divided by one twelfth of the number of whole calendar months in the period commencing on the date the Positive Change Event occurred and expiring at the end of the Regulatory Control Period; and
>
> (b) in the case of a Negative Change Event for that DNSP, the Negative Pass Through Amount in respect of that Negative Change Event divided by one twelfth of the number of whole calendar months in the period commencing on the date the Negative Change Event occurred and expiring at the end of the Regulatory Control Period.[32]

NSW DNSPs have suggested that there has been uncertainty in the application of the threshold to capex.

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[29] ICRC Draft Decision, Investigation into prices for electricity distribution services in the ACT, November 2003

[30] Ibid, p.118.

[31] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Determination, p 129

[32] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09, p.44.

Although expressed as an average annual change in *costs*, the average annual change in costs was calculated using the 'Approved Pass Through Amount'. This amount was calculated as the revenue impact of the costs.[33] Therefore, the IPART threshold compared average annual revenue impact with the average annual smoothed revenue.

IPART's approach is represented in the following formula:

Average annual revenue impact over the remaining life of the regulatory period	> 1% average annual smoothed revenue

Where:

Average annual revenue impact over the remaining life of the regulatory period is calculated as:

$$\left(\frac{\text{revenue impact}}{X}\right)\times 12$$

And:

Revenue impact	=	the revenue impact of the total cost (both opex and capex) of the pass through event during the regulatory period (determined in accordance with the post tax revenue model)
X	=	the number of months remaining in the regulatory period
Average annual smoothed revenue	=	sum of the annual revenue requirement for each regulatory year of the regulatory control period/number of years in the regulatory control period.

IPART's financial modelling indicated that cost increases under this threshold would be unlikely to have a serious impact on the financial position of the DNSP if it had to wait until the next review for higher costs to be reflected in the DNSP's X-factors/revenue requirements.

4.3.3 Materiality in the transmission Rules

Rather than assessing the revenue impact of an event, the transmission Rules generally assess the costs of an event.

4.3.3.1 Cost pass throughs for TNSPs

Clause 6A.7.3 of the NER provides for the reopening of a revenue determination to accommodate the pass through of costs in specified circumstances. An event must satisfy the materiality threshold in order to constitute a pass through event. Materially is defined in the glossary of the NER as:

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[33] See IPART, NSW Distribution Network Cost Pass Through Review, Statement of Reasons for decision, 5 May 2006, available at www.ipart.nsw.gov.au.

> For the purposes of the application of clause 6A.7.3, an event (other than a network support event) results in a Transmission Network Service Provider incurring materially higher or materially lower costs if the change in costs (as opposed to the revenue impact) that the Transmission Network Service Provider has incurred and is likely to incur in any regulatory year of the regulatory control period, as a result of that event, exceeds 1% of the maximum allowed revenue for the Transmission Network Service Provider for that regulatory year.

This definition does not distinguish between operating and capital costs, however, due to the nature of the events specified in the transmission Rules, transmission pass throughs have generally only been approved to date for opex.

Unlike the distribution Rules, pass through events under Chapter 6A are exhaustively defined; there is no scope to specify additional events that may constitute pass through events. However, Chapter 6A provides other specific mechanisms to reopen a determination for changes in capital costs.

4.3.3.2 Reopening of revenue determination for capital expenditure

Clause 6A.7.1 of the NER provides for the reopening of a revenue determination to include additional capex, in specified circumstances. The total of the capital expenditure under clause 6A.7.1 must exceed 5 per cent of the regulated asset base.

4.3.3.3 Contingent projects

Clause 6A.8.1 provides that contingent projects may be included in a revenue determination if the proposed capital expenditure exceeds either $10 million or 5 per cent of the value of the maximum allowed revenue for the relevant TNSP for the first year of the relevant regulatory control period, whichever is the larger amount.

An event that is included in the revenue determination as a contingent project is excluded from the operation of the pass through provisions.

4.4 Issues for the 2009-2014 determination

The purpose of the pass through provisions is to allow the regulatory determination to be adjusted to deal with uncertain events that are beyond the control of the DNSP. In the absence of pass through provisions, DNSPs will generally absorb the benefits or costs if the events do occur.

The AER considers it important to set an appropriate materiality threshold for pass throughs as the threshold represents a trade-off between ensuring that:

- it does not create a ‘cost-plus’ form of regulation, and
- it does not exclude events that have a serious impact on the DNSP’s financial position.

In the context of distribution, it is likely that pass through events may require both opex and capex. The AER considers that a threshold should be clear in its application to both opex and capex.

4.4.1 Should costs or revenue impact be assessed?

While the revenue impact of additional opex is reasonably simple to determine (generally $1 in opex will increase the revenue requirement by $1), the revenue impact of an increase in capex is more difficult to calculate, as it involves assumptions about asset lives and rates of return. IPART addressed this difficulty by modelling the revenue impact of increases in costs.

The transmission pass through Rules, however, explicitly state that the costs, rather than the revenue impact, are to be assessed. The other provisions in the transmission Rules allowing for the regulatory determination to be reopened also require an assessment of the costs.

Consistent with the ICRC, IPART and the transmission Rules, the AER will consider determining a percentage threshold of a relevant revenue allowance. As the revenue impact of an event is lower than the cost impact, a threshold that is applied to revenue impact should be lower than a threshold applying to costs. This is reflected in IPART's threshold of 1% based on revenue impact, compared to the ICRC's approach of around 7.5% based on costs, and the transmission approach in contingent projects of 5% of costs.[34]

The AER seeks submissions on whether the threshold should apply to the costs of an event, or the revenue impact of an event. The AER is likely to apply a threshold in the order of 1% if revenue impact is the basis for assessment, and a threshold of around 5 – 7 % if costs are the basis for assessment.

4.4.2 To what measure of revenue should costs or revenues be compared?

In determining the relevant revenue allowance against which the threshold will be assessed, there are a number of options:

- the total revenue requirement over the period may be averaged to derive an average annual amount, consistent with the approach adopted by IPART
- the revenue requirement can be assessed on an individual yearly basis, so that the costs incurred in a particular year are assessed against the revenue requirement in that same year, consistent with the approach for cost pass throughs in the transmission Rules
- the revenue requirement may be fixed as the revenue requirement for the first year of the regulatory control period, consistent with the approach for contingent projects in the transmission Rules
- the total revenue requirement for the regulatory control period could be used, so that the total costs or revenue impacts of the event during the regulatory control period are compared to this amount (rather than averaging costs and/or revenue impacts).

It is desirable for the measure of revenue selected to be consistent with the measure of the costs or revenue impact of the event – if *total* revenue is selected it ought to be compared to *total* costs or revenue impacts of the event, and if *average* revenue is selected it ought to be compared to *average* costs or revenue impacts of the event.

[34] While the transmission threshold for cost pass throughs is 1%, it appears that this provision has generally been limited in application to opex.

4.5 Request for submissions

The AER seeks submissions on the following issues:

1. Should materiality be assessed based on the costs of an event during the regulatory control period, or the revenue impact of an event in the regulatory control period?

2. Should the costs or revenue impact of an event be measured on an average annual basis, or measured as the total costs or revenue impact of the event for the remainder of the regulatory control period?

3. To which of the following measures of revenue should the costs or revenues of the event during the regulatory control period be compared?

    - the total revenue requirement over the period is averaged to derive an average annual amount
    - the revenue requirement is assessed on an individual yearly basis, so that the costs or revenue impact in a particular year are assessed against the revenue requirement in that same year
    - the revenue requirement is fixed as the revenue requirement for the first year of the regulatory control period
    - the total revenue requirement for the regulatory control period is used, so that the total costs or revenue impacts of the event during the regulatory control period are compared to this amount (rather than averaging costs and/or revenue impacts)

Submissions may also address the likely magnitude of the administrative costs of modifying current practices.