Issues paper

Potential development of demand management incentive schemes for Energex, Ergon Energy and ETSA Utilities for the 2010–15 regulatory control period

April 2008

AUSTRALIAN ENERGY REGULATOR

Contents

Shortened forms

ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
COAG	Council of Australian Governments
DMIS	demand management incentive scheme
DNSP	distribution network service provider
ESCV	Essential Services Commission (Victoria)
IPART	Independent Pricing and Regulatory Tribunal (NSW)
MCE	Ministerial Council on Energy
NEM	National Electricity Market
NER	National Electricity Rules
NSW	New South Wales
opex	operating expenditure
QLD	Queensland
SA	South Australia
WAPC	weighted average price cap

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 Friday, 16 May 2008. Chapter five of this paper sets out some specific issues for submissions to address.

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

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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 Introduction

The Australian Energy Regulator (AER) is responsible for the economic regulation of distribution network service providers (DNSPs) in the National Electricity Market (NEM) in accordance with the National Electricity Rules (NER), which commenced on 1 January 2008. The AER is preparing to make distribution determinations to apply to Ergon Energy, Energex and ETSA Utilities for the 2010–15 regulatory control period.

The NER require that in preparing to make these determinations, the AER must prepare and publish framework and approach papers relevant to each DNSP. These papers must set out, among other things, the AER's likely approach to the application (if applicable) to DNSPs of demand management incentive schemes (DMIS). The NER state that the framework and approach papers must be completed at least 19 months before the end of the Queensland (QLD) and South Australia (SA) 2005–10 regulatory control periods, that is by 30 November 2008.

Preparation of and consultation on the framework and approach papers for Energex, Ergon Energy and ETSA Utilities must, under the NER, commence by 30 June 2008. The AER expects to initiate public consultation on the potential for a national DMIS in mid 2008, with the publication of an issues paper. Consultation on a national DMIS will not be completed in time for the AER to consult on a likely approach to its application to the QLD and SA DNSPs. However, where possible, the AER will endeavour to ensure consistency between the national scheme and schemes to apply to QLD and SA DNSPs.

This issues paper discusses whether a DMIS should be developed for Energex, Ergon Energy and ETSA Utilities for their 2010 distribution determinations, and if so what form it should take.

While it has been decided to combine the demand management issues in QLD and SA within this paper, it is not necessary that any scheme developed by the AER following this consultation process will be the same for QLD and SA DNSPs. Should the AER decide to apply a DMIS in QLD or SA, it will publish a draft scheme for consultation by 30 June 2008.

1.1 Demand management incentive schemes under chapter 6 of the NER

The NER provide for various incentive schemes to be prepared by the AER for application in distribution determinations. Among these is a DMIS to provide incentives for DNSPs to implement efficient non-network alternatives or to manage expected demand for standard control services in some other way. Clause 6.6.3 of the NER states that:

> (b) In developing and implementing a *demand management incentive scheme*, the AER must have regard to:
>
> (1) 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 *Distribution Network Service Providers*; and

(2) the effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a *Distribution Network Service Provider*'s incentives to adopt or implement efficient non-network alternatives; and

(3) the extent the *Distribution Network Service Provider* is able to offer efficient pricing structures; and

(4) the possible interaction between a *demand management incentive scheme* and other incentive schemes; and

(5) the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme.

1.2 Rationale for a demand management incentive scheme

Demand management refers to any strategy to address growth in demand and/or peak demand. Demand management can have positive economic impacts by reducing peaks and encouraging the more efficient use of existing network assets, resulting in lower prices for network users and benefits for the environment. Network owners can seek to undertake demand management through a range of mechanisms, such as incentives for 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 investments, by deferring the need for augmentations to relieve network constraints. For example, a fall in demand as a result of a demand management project may result in the deferral of construction of a new line, which would enable an increased load to meet growing demand in a particular area. Costs of network augmentation projects can be significantly greater than the costs of conducting demand management projects to defer an augmentation project. Deferral of network investment may result in efficiency benefits, as the same level of reliability and service is provided by a smaller, greater utilised network.

There are several factors in the electricity market and regulatory framework which may prevent an efficient level of demand management being undertaken by DNSPs:

- Lack of information regarding demand management is a primary barrier, in particular limited information regarding end-user attitudes and responses to demand management, as well as information about the effectiveness and reliability of demand management projects.

- Flat retail tariffs which limit the ability of consumers to identify and react to price signals are also barriers to demand management.

- The electricity market structure, which may allow the benefits of demand management projects to flow onto retail and generation sectors despite costs being incurred only by DNSPs, may also prevent DNSPs from taking up demand management.

- Service and reliability standards obligations may also be barriers to efficient demand management. A DNSP that undertakes demand management instead of network investment faces the risk of not meeting its prescriptive reliability standards imposed within DNSP licensing conditions, if the demand management is unsuccessful in lowering network demand. DNSPs may be reluctant to utilise non-network solutions to address rising peak demand, instead perceiving network augmentation investment as a more reliable response.

The purpose of applying a DMIS is to reduce the barriers to demand management and encourage DNSPs to undertake an efficient level of demand management in response to rising demand on their networks.

2 Operating environment for demand management in QLD and SA

2.1 Introduction

This section provides an overview of the operating environment for demand management in QLD and SA, and then outlines some existing and potential incentives for DNSPs to conduct demand management.

2.2 Operating environment in Queensland

Rising summer peak demand is an issue common to DNSPs across the NEM, due in part to the increasing use of residential air conditioners and other appliances. Strong economic and population growth are also contributing to an increasing demand for electricity. Both Energex and Ergon Energy's 2006–07 annual reports detail record work programs for network expansion to meet this rising demand.

Ergon Energy's *Sustainability Report 2007* states that in recent years there has been a three fold increase in customer–initiated works and new connections on its network, as a result of strong growth in regional QLD.[1] It states that the maximum demand on Ergon Energy's network has been increasing at around 5.5 per cent per annum, due largely to the increased use of air conditioning, other appliances, and the mining boom.[2] Ergon Energy forecasts maximum demand on its network to grow by an average of 4.3 per cent per annum over the next few years.[3]

Maximum demand on Energex's network is forecast to grow by 5.9 per cent over summer 2007–08.[4] While the *Energex Annual Network Management Plan for 2007–08* outlines an expected period of high growth in demand for electricity over the next couple of years, it also notes that as air conditioner and other appliance saturation occurs, growth in energy demand is expected to stabilise in South East QLD over the 2010–15 period.[5]

Growth in peak demand and planned network expenditure in QLD indicate that there is potentially a role for demand management in Energex and Ergon Energy's networks. Demand management may assist the QLD DNSPs to meet forecast demand requirements while maintaining or reducing the level of planned expenditure on their networks.

2.3 Operating environment in South Australia

While South Australia's aggregate demand for electricity is not the highest in the NEM, ETSA Utilities' *Demand Management Program - Interim Report 2007* states that South Australia's 'peakiness' of demand is the highest in Australia and ranks amongst the highest in the world, with approximately 1/3 of network capacity

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1 Ergon Energy, *Ergon Sustainability Report 2007*, 2007 p. 28.
2 ibid.
3 ibid.
4 Energex, *Energex Summer Preparedness Plan 2007–08*, p. 1.
5 Energex, *Energex Annual Network Management Plan 2007/08 to 2011/12*, p. 31-2.

required for only 1 per cent to 2 per cent of the year.[6] This is largely attributed to a climate characterised by hot, dry summers, driving the summer air-conditioning needs of residential customers.

Historically, South Australia's air-conditioner penetration has been extremely high, and ongoing trends to upgrade the existing air-conditioner stock exacerbate growth in residential peak demand. Due to protracted hot weather conditions, a new record peak for instantaneous demand in ETSA Utilities' network of 2847 MW was reached on 17 March 2008, an 8 per cent increase on the previous record of 2633MW, seen two years earlier in January 2006. Peak demand remains a key driver for new network investment and capital expenditure, and therefore costs to customers.[7]

Recent regulatory decisions by the Essential Services Commission of South Australia considered in detail the merits of various measures to reduce peak demands on ETSA Utilities' network, and concluded that a reduction in peak demand through application of various demand management initiatives had the potential to result in more efficient use of existing infrastructure and a lower level of investment in new infrastructure through either deferral of, or removal of the need for, network augmentation and/or expansion expenditures.

Pilot programs under the price determination

Within the current regulatory period, ETSA Utilities has commenced a number of pilot demand management programs as required by the Essential Services Commission of SA in the *2005-10 Electricity Price Determination* for ETSA Utilities.[8]

The purpose of the pilot demand programs is to identify demand management initiatives that are cost effective (that is to say, permit ETSA Utilities to meets its supply obligations at a lower cost than expenditure on network augmentation). Viable demand management initiatives identified by these pilot programs were intended to be considered for wider implementation during the 2010-2015 regulatory period.

Electricity Industry Guideline No. 12

In addition, the Essential Services Commission of SA requires ETSA Utilities, as a condition of its distribution licence issued pursuant to Part 3 of the *Electricity Act 1996* (SA), to investigate the use of demand management as a means of deferring the need for significant expansions or augmentations of its distribution network in areas where the network is becoming constrained.[9]

In 2003, the Essential Services Commission of SA developed a guideline, *Electricity Industry Guideline No. 12, Demand Management for Electricity Distribution Networks* (Guideline 12), specifying the steps to be taken by ETSA Utilities in order

6 ETSA Utilities Demand Management Program - Interim Report June 2007 report, p. 11

7 ibid, p. 64.

8 The Essential Services Commission of SA's final decision on this matter is outlined in Chapter 4 of its decision, available at http://www.escosa.sa.gov.au.

9 ETSA Utilities Distribution Licence, clause 14 (http://www.escosa.sa.gov.au/webdata/resources/files/071107-D-ETSAUtilitiesElecDistLicence.pdf)

to satisfy the demand management obligations placed on it under its licence.[10] Those steps include:

- annual publication of an Electricity System Development Plan which details expected network constraints over the next three years;
- consulting with interested parties on demand management alternatives for all network extensions and augmentations with an estimated capital cost over $2 million.

The objective of *Guideline No 12* is to improve the transparency and robustness of ETSA Utilities' demand management obligations.

During 2006/07, the Essential Services Commission of SA completed a review of *Guideline 12.* The purpose of the review was to assess whether or not the guideline was achieving its objectives and to identify opportunities for improving its effectiveness. As a result of the review, the Essential Services Commission of SA has amended the guideline to ensure to that adequate information is provided by ETSA Utilities to all interested parties to facilitate demand management initiatives, but also to encourage a better interaction between customers and ETSA Utilities when considering alternatives to network augmentation.

Progress

In its June 2007 progress report on ETSA Utilities' demand management program, the Essential Services Commission of SA noted that there has been little reporting to date that would indicate the success or otherwise of specific initiatives in achieving the program's objective of cost effective deferral of network augmentation, with the focus of reporting at that time having been establishment and implementation of specific initiatives.[11] The Essential Services Commission of SA was, however, able to conclude that ETSA Utilities had laid out a comprehensive framework for delivery of the demand management program outlined in the price determination, and that it had established appropriate organisational arrangements and resourcing.[12]

Application of a DMIS in the AER's distribution determination for ETSA Utilities in the next regulatory period could facilitate continuation of such initiatives where it is prudent to do so.

2.4 Existing and potential opportunities for demand management

The operating environment of both the QLD and SA markets suggest that a DMIS may have a role to play in these jurisdictions. However, aside from any DMIS, there are other existing and potential demand management initiatives which may have an impact on the level of demand management carried out by DNSPs:

10 http://www.escosa.sa.gov.au/webdata/resources/files/070628-O-Guideline12-DemandManagementV2_Final.pdf.

11 Essential Services Commission of SA, Progress Report – ETSA Utilities Demand Management Program, June 2007, p. 32.

12 ibid., p. 31.

- The NER allow the AER to apply different control mechanisms, such as tariff basket, revenue yield or revenue cap arrangements, to a DNSP’s distribution services. The AER is aware that different control mechanisms may have different incentive effects on a DNSP's willingness to undertake demand management. For example, under a weighted average price cap (WAPC) a DNSP may have lower incentives to undertake demand management as it could result in lower demand and therefore lower revenues. On the other hand, a DNSP under a revenue cap arrangement may have more incentive to undertake demand management as it would still receive the same revenues regardless of whether or not demand was reduced during the period. It is noted that, in relation to its QLD and SA distribution determinations, the AER is not required to make a decision on the control mechanism to be applied to these businesses until August and November 2008 respectively (as part of the framework and approach paper processes). Should the AER decide to develop a DMIS for Energex, Ergon Energy or ETSA Utilities, it will need to give due regard to the control mechanisms that may be applied to the DNSP and their potential incentive effects.

- DNSPs may have an incentive to conduct demand management where it is more economically efficient than implementing network augmentation. The AER will approve the recovery of a certain amount of forecast capex for each DNSP at the time of its distribution determination. For any planned capex that is deferred or deemed no longer necessary during the regulatory control period, DNSPs are able to retain the return on and of these underspends for the remainder of the regulatory control period. This may provide incentives for DNSPs to seek ways to meet their supply obligations by managing demand on their networks, thereby deferring the need for capex and retaining the return on and return of the costs for the amount of capex deferred for the remainder of the regulatory control period.

- Clauses 6.5.6(a)(1) and 6.5.7(a)(1) of the NER require that a building block proposal must include the total forecast operating expenditure (opex) and capital expenditure (capex), respectively, which the DNSP considers is required to meet or manage the expected demand for standard control services over the regulatory control period. Inclusion of forecast opex and capex for demand management in a building block proposal and, subject to the requirements of those clauses, the AER’s building block determination, is explicitly allowed under the NER.

- Clauses 6.5.6(e) and 6.5.7(e) of the NER require that, in determining whether it is satisfied with a DNSP’s forecasts of capex and opex, the AER must have regard to the extent to which the DNSP has considered and made provision for non-network alternatives. While these clauses may not expressly place obligations on the DNSPs to demonstrate that they have had specific regard to demand management alternatives to capex and opex projects, this information is necessary to inform the AER’s assessment of DNSPs’ expenditure forecasts. As such, DNSPs will need to put forward details of their consideration of efficient non–network alternatives as part of their regulatory proposals.

- State government demand management initiatives provide DNSPs with additional incentives and funding to carry out demand management projects on their networks. For example, the NSW Department of Water and Energy runs an Energy Savings Fund, which will provide $200 million of funding over the period

2005–10. Several of the NSW DNSPs have received funding for demand management and energy efficiency programs under the Energy Savings Fund.

- The Council of Australian Governments (COAG) is currently undertaking a cost-benefit analysis of a national mandated roll-out of electricity smart meters. The AER understands that a national roll-out of smart meters will be considered by COAG before the 2010–15 regulatory control period. One of the potential motivations for a mandatory smart metering roll-out is to provide 'a capability to manage network demand where jurisdictions face significant demand growth, in order to delay the need for expensive investment in network capacity and peak generation.'[13]

- The Australian Energy Market Commission (AEMC) is currently undertaking a review of demand side participation in the NEM, and is exploring the potential for greater incentives for demand management. This review is expected to be completed in December 2008. The AEMC has expressed concerns about the possibility of sub-optimal investment in alternative demand-side solutions, compared with investments in generation and networks. If these concerns are confirmed, the AEMC may look to amend the NER in order to facilitate efficient demand side participation in the NEM.[14]

- In addition to this review, broader climate change policies mandated in the future, for example an emissions trading scheme, may create incentives for DNSPs to conduct demand management.

2.5 Conclusion

The current level of demand management being carried out by ETSA Utilities appears to be greater than that carried out by DNSPs in QLD, indicating that there may be more scope for demand management incentives in QLD than in SA. However, there is currently insufficient information regarding the outcomes of demand management programs in SA. In addition to any DMIS that the AER decides to apply, there are a number of sources of existing and potential demand management initiatives for DNSPs. Despite these existing and potential initiatives, there may be benefits to be gained by consumers and DNSPs by encouraging DNSPs to undertake further demand management. Accordingly, it is understood that there are sufficient reasons for the AER to consider the development of DMIS for QLD and SA.

13 NERA, *Cost benefit analysis of Smart Metering and Direct Load Control – Overview report for consultation*, 20 February 2008, p. 7.

14 AEMC, *Review of demand side participation in the NEM – Terms of Reference.*

3 Current demand management initiatives

3.1 Introduction

This section discusses some of the demand management initiatives and DMIS currently in operation in all jurisdictions of the NEM, to highlight the range of options which could potentially be applied in QLD and SA.

3.2 Queensland

There is currently no DMIS in place in QLD. In its 2005 determination, the Queensland Competition Authority stated that:

> While some regulators have recently begun to modify their regulatory approach to provide positive incentives for demand management initiatives, the Authority is not convinced about the need to introduce such incentives into the revenue cap arrangements at this time.
>
> Both DNSPs will have significantly increased total expenditure budgets over the next regulatory period which will allow them to pursue demand management options if they choose, regardless of whether demand management projects have been specifically identified in the opex and capex proposals the DNSPs presented to the Authority in preparing this Final Determination….In principle, the Authority is unlikely to be concerned if the DNSPs spend more funds on efficient demand management projects than originally envisaged.[15]

In July 2004, an independent panel appointed by the QLD government undertook a review of electricity distribution systems in QLD.[16] While the panel was not required to consider demand management in detail, it saw merit in the QLD government and distributors working collaboratively to explore it further as a means of managing growth in peak demand. The panel highlighted a NSW state license requirement for DNSPs in that state to consider demand management before expanding their networks, and recommended that such measurements be introduced in QLD.[17] The panel also considered that there was scope for kVA tariffs to be introduced for large industrial customers, as is common in other states in Australia and around the world.[18] The panel recommended that the QLD government and DNSPs work together to develop kVA tariff structures in order to better assist in the management of peak demand and improve the overall utilisation of the network.[19]

While there is no DMIS in place in QLD, Energex and Ergon Energy are currently undertaking demand management projects.

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15 Queensland Competition Authority, *Final determination –Regulation of Electricity Distribution*, April 2005, p. 185.

16 Independent Panel (chaired by Darryl Somerville), *Detailed report of the Independent Panel – Electricity distribution and service delivery for the 21st century*, Queensland, July 2004, pp. 200-202.

17 ibid. p. 201.

18 KVA tariffs charge customers for the capacity supplied to them, rather than the energy received by them in kW terms, thereby encouraging the customers to install power factor correction equipment to increase the efficiency of their operations.

19 ibid. p. 202.

Energex's *Annual Network Management Plan 2007–08 to 2011–12* outlines a number of demand management projects that it is carrying out to try to address rising peak demand.

Energex established agreements with large commercial and industrial customers for a total of 16 MVA of network support in the summer of 2006–07.[20] Customers agreed to shift their loads to an off-peak time, support the network with their own generators when required, or allow Energex to install mobile generators at their sites for use at peak times.[21] Energex also directly controls residential customer hot water load, which allows approximately 350 MW of demand reduction over the winter evening peak, and 60 MW over the summer evening peak.[22]

Energex is conducting a trial of small customer air conditioner direct load control, known as 'Cool Change.' Energex customers living in Albany Creek, Arana Hills and surrounding areas that operate a split or ducted air conditioner are able to participate in the trial by allowing Energex to install a device that cycles their air conditioner compressor on and off. The trial has run over the 2007–08 summer, and participating customers are paid $100 upon connection of the cycling device. The trial is aiming to determine the impacts of direct load control demand management on peak electricity demand.

In addition to these demand management projects, Energex is conducting a customer education program to teach customers ways to be more energy efficient in their homes and businesses. This education program is conducted via Energex's website, www.energex.com.au.

Ergon Energy is participating in the Solar Cities Program, which is a $75 million Australian Government initiative that aims to demonstrate ways for customers to save energy. Ergon Energy's participation in the program is through its Townsville Queensland Solar City project, whereby Ergon Energy is providing some funding for the program, along with a number of other organisations. The project is aiming to showcase the uptake of solar power, energy efficiency measures and smart metering by households and businesses, as well as focussing attention on energy markets and the delivery of more cost reflective price signals. The objective of the project is to trial a sustainable business model for concentrated deployment of distributed generation (in this case, solar photovoltaics) and demand management (utilising deployment of energy efficiency, load management, smart meters and innovative tariffs). The project involves:

- installation of solar panels on some residential and commercial buildings, to be owned and managed by Ergon Energy
- free energy assessments of households and commercial buildings
- installation of smart meter displays to show customers a range of information, including how much electricity they are using at a particular time
- the provision of free energy-saving light bulbs.

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20 Energex, *Annual Network Management Plan 2007–08 to 2011–12,* 16 August 2007, pp. 82.
21 ibid.
22 ibid.

The AER is aware that Ergon Energy is undertaking other demand management projects within its network. Ergon Energy is also conducting a customer education program via its website, www.ergon.com.au. This program provides customers with information on how to save energy by being more energy efficient around homes and businesses.

3.3 South Australia

In its *2005–10 Electricity Distribution Price Determination*[23] for ETSA Utilities, the Essential Services Commission of SA provided an opex allowance of $20.4 million to fund a range of pilot demand management programmes and initiatives over the 2005–10 regulatory control period.[24] These were 'mostly pilot programs for specific initiatives, as well as activities designed to build ETSA Utilities' demand management capabilities and to aggregate the benefits of demand management across the industry'.[25]

The range of approved demand management initiatives were selected on the basis of a detailed cost-benefit analysis undertaken for the Essential Services Commission of SA by Charles River Associates (CRA) [26]. Following the price determination, ETSA Utilities was required to submit a comprehensive scope of initiatives and detailed work plan for approval by the Essential Services Commission of SA[27]. This work plan encompassed the areas identified by CRA, being:

- residential demand management (direct load control)
- embedded generation
- power factor correction
- load limitation
- aggregation
- critical peak pricing.

The allowance was categorised as opex, rather than capex, and is not an amount to be incorporated into ETSA's regulatory asset base. Recognising the pilot nature of the programs, the Essential Services Commission of SA did not consider it appropriate to make adjustments to demand forecasts, capex forecasts or lost revenue within the regulatory control period to reflect expected outcomes. The allowance differs to that of other approved opex as there are no 'efficiency gains' to be made through underspending. Any expenditure above the allowance in the price determination for these projects is to be at ETSA Utilities' cost. Any underspend is not to be treated as an efficiency gain for the purpose of the efficiency carryover mechanism in the price

23 The Essential Services Commission of SA's final decision on this matter is outlined in Chapter 4 of its decision, available at http://www.escosa.sa.gov.au.

24 Essential Services Commission of SA *2005-2010 Electricity Distribution Price Determination Part A: Statement of Reasons* April 2005, pp. 53 and 60.

25 ibid. p. 64.

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

27 ETSA Utilities, *Demand Management, The Way Forward, 2005/06 - 2009/10,* October 2005.

determination, so that ETSA Utilities is not rewarded for that underspend in the following regulatory control period.

The Essential Services Commission of SA has not prescribed the manner in which ETSA Utilities is to implement demand management initiatives within the categories approved in the price determination, but monitors and reports publicly on progress.[28] Specific reporting requirements apply for each initiative under the Essential Services Commission of SA's Guideline 12, which requires ETSA Utilities to submit an Annual Demand Management Compliance Report. For each of the trials identified in the approved work plan the report must provide information on the progress and performance of the demand management initiatives against defined indicators.

3.4 Australian Capital Territory and New South Wales

The Independent Competition and Regulatory Commission, which was the jurisdictional regulator of ActewAGL at the time of the current distribution determination, did not apply any financial incentives to encourage ActewAGL to pursue demand management activities in its 2004 distribution determination.

The Independent Pricing and Regulatory Tribunal of NSW (IPART) was the jurisdictional regulator for electricity distribution businesses in NSW, prior to the transfer of this role to the AER in January 2008. IPART's 2004 distribution determination introduced incentives for DNSPs to conduct demand management. This was driven largely by a perception that the WAPC, which was first applied to the NSW DNSPs at the time of the 2004 determination, may create disincentives for DNSPs to conduct demand management. The mechanism through which the incentives operate is an adjustment factor within the WAPC known as the D-factor.

On 29 February 2008, the AER released its final decision on DMIS to apply to the ACT and NSW DNSPs for the 2009–14 regulatory control period.[29] Following a stakeholder consultation process, the AER decided to continue the D-factor for NSW DNSPs, and in addition to apply a demand management innovation allowance to both ACT and NSW DNSPs.

3.4.1 The D-factor

The D-factor is a yearly allowed adjustment to the WAPC that enables a DNSP to recover through prices the additional costs of demand management projects in a year, relative to the previous year. Typically, demand management projects recovered under the D-factor target network congestion, and cost recovery is based upon a reduction in planned network capex. Figure 1 contains the D-factor formula.

28 Essential Services Commission of SA, *Progress Report – ETSA Utilities Demand Management Program*, June 2007, p. 7.

29 AER, *Final Decision – Demand management incentive schemes for the ACT and NSW 2009 distribution determinations*, February 2008.

Figure 1. The D-factor formula

$$D_{t+1} = \frac{DM\ Cost\ Pass\ Through\ Amount_{t-1}}{SRR_t - AF\ \mathrm{Re}venue_{t-1}} - \frac{DM\ Cost\ Pass\ Through\ Amount_t}{SRR_{t-1} - AR\ \mathrm{Re}venue_{t-2}}$$

Where:

D_{t+1} is the D-factor to be included in the price control formula for Year *t+1*

$AF\ \mathrm{Re}venue_{t-1}$ is the amount approved by the Tribunal for recovery by the DNSP of foregone revenue in Year *t-1*

$AR\ \mathrm{Re}venue_{t-2}$ is the amount approved by the Tribunal for recovery by the DNSP of foregone revenue in Year *t-2*

$DM\ Cost\ Pass\ Through\ Amount_{t-1}$ is the DM Cost Pass Through Amount calculated for the DNSP for the Year *t+1* – the sum of the demand management implementation costs and foregone revenue incurred in Year *t-1*, as approved by the Tribunal

$DM\ Cost\ Pass\ Through\ Amount_t$ is the DM Cost Pass Through Amount calculated for the DNSP for the Year *t*

SRR_t is the smoothed revenue requirement for the DNSP for the Year *t*

SRR_{t-1} is the smoothed revenue requirement for the Year *t-1*

Source: IPART *NSW Electricity Distribution Pricing 2004-05 to 2008-09 Final Report* p. 99

Demand management project implementation costs may be recovered by a DNSP up to a maximum of the value of the avoided network expenditure resulting from the demand management project. Foregone revenue costs resulting from a demand management project may also be recovered under the D-factor. DNSPs must demonstrate to the AER the link between the demand management project and a reduction in network expenditure for cost recovery approval under the D-factor.

A DNSP can achieve a positive or negative D-factor in any year. A DNSP will achieve a positive D-factor if the demand management costs (proportionate to the adjusted smoothed revenue requirement) in year *t-1* are greater than in the previous year, *t-2*. A positive D-factor increases the WAPC, and therefore the allowed average price increase of network tariffs applied by a DNSP. A DNSP will achieve a negative, or zero, D-factor when the DNSP decreases, or only maintains, the level of its demand management costs, that is, when demand management costs in year *t-1* are less than, or equal, the previous year, *t-2*. A negative D-factor removes the effect on prices of a D-factor increase in year *t-2*, which would otherwise have a cumulative impact on price persisting throughout the regulatory period. This would result in an over–recovery demand management costs in year *t-1* and the remainder of the regulatory period.

Cost recovery under the D-factor is on an ex post basis, and there is a two year lag between demand management cost outlay and recovery through higher prices. This is because prices must be determined by the AER one year before they are implemented and foregone revenue can be calculated only after the impact of the project is analysed for its actual effect on revenue.

DNSPs can apply to the AER in advance of implementing their demand management projects for preliminary assessment on whether their approach to estimating foregone revenue is reasonable, prior to a demand management project being implemented. DNSPs may apply to the AER to be allowed to recover a portion of the avoided network expenditure resulting from demand management projects which only partially relieve a network constraint. This allows DNSPs that are unable to finish a capex project in time to meet an emerging network constraint, to implement demand management projects and subsequently recover demand management costs, up to the value of the partially avoided network costs.

As noted above, the D-factor was introduced by IPART in its 2004 distribution determination primarily to offset perceived disincentives to conduct demand management within the WAPC. The AER decided to continue the operation of the D-factor over the 2009–14 regulatory control period for the following reasons:

- the continued perception that the WAPC may provide disincentives for DNSPs to conduct demand management
- strong support from stakeholders for the continuation of the scheme
- the fact that the D-factor has only been in place for a short time, and there is currently insufficient information available to be able to make an assessment as to whether the scheme has been effective or not.

Between 2004–05 and 2005–06, NSW DNSPs spent approximately $8.26 million on 26 demand management programs under the D-factor scheme.[30] Over this period NSW DNSPs avoided $24.23 million of planned capex and opex through the approved demand management projects.[31]To date the impact of the D-factor on customer prices has been small, the largest impact was less than five cents on an average customer's annual bill.[32]

3.4.2 Demand management innovation allowance

The demand management innovation allowance will allow the ACT and NSW DNSPs to recover amounts ranging from $100 000 to $1 million per annum over the 2009–14 regulatory control period. The amounts were determined as broadly proportional to the size of each DNSP's network. They are reflective of the AER's position that, given the existing and potential demand management incentives (such as those outlined in section 2.4) it is appropriate to allow a modest allowance. It is expected that the amounts provided under the scheme will allow DNSPs to conduct a number of demand management projects over the regulatory control period.

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30 IPART, *NSW Electricity Information Paper No 2/2007 - Demand Management in the 2004 distribution review: progress to date*, 2007, p. 3.
31 ibid., p 4.
32 ibid., p 5.

To obtain the amounts under the demand management innovation allowance, DNSPs must undertake efficient demand management projects and make claims for the associated costs, to be approved by the AER. If DNSPs do not carry out any demand management projects that are approved under the scheme, they will not be eligible to recover the allowance. That is, the demand management innovation allowance operates on a ‘use it or lose it’ basis.

Assessment of demand management projects will be carried out in two stages: a prior approval stage to establish the aims of the project, followed by final approval at the end of the demand management project. Cost recovery under the demand management innovation allowance will be on an annual, ex post basis for the implementation and foregone revenue costs of approved demand management projects, and will be incorporated into the annual DNSP price review process. Once completed, demand management projects will be assessed by the AER, and any necessary cost recovery will, subject to the established caps, occur via price adjustments during the next annual DNSP price review process. Demand management undertaken as part of the scheme will not be subject to auditing requirements, to ensure the administrative costs of conducting demand management under the scheme do not unreasonably erode the available cost recovery.

Projects eligible for recovery fall within the following criteria:

- demand management projects claimed under the scheme should not be recoverable under categories of the D-factor

- costs recovered under the scheme must not be recovered under any other state or Australian government schemes

- demand management projects to be recovered under the scheme should be innovative, and/or target broad–based demand reductions across the DNSPs’ networks

- recoverable programs may be tariff or non–tariff based, however, the foregone revenue of tariff based demand management will not be recoverable under the scheme.

At the completion of the annual DNSP price review, the AER will publish, for each DNSP, the available allowance and amount claimed under the demand management innovation allowance for demand management expenditure in the previous regulatory year.

The demand management innovation allowance was applied in response to strong support from stakeholders, and recognises the view that there may be broad–based demand management projects that have the potential to generate efficient outcomes through greater utilisation of existing network assets. Typically, broad–based demand management projects are those that aim to spread reductions in demand over a wide section of a DNSP’s network, rather than aiming to reduce demand within a specific constrained area of the network (such as within the D-factor scheme). While broad–based demand management may not provide immediate capex deferral benefits to DNSPs, the AER considers that an efficient level of broad–based demand management will be in the long term interests of both DNSPs and consumers.

In contrast to the D-factor, which is an uncapped, targeted mechanism, the demand management innovation allowance is a capped mechanism that allows recovery for broader demand management across a network.

3.5 Victoria

The Essential Services Commission of Victoria (ESCV) considered demand management in its *Electricity Distribution Price Review 2006–10* (2006-10 EDPR). The ESCV's decision was based on the principle that the application of incentives for demand management within a regulatory framework should not impose negative consequences on customers with respect to price, quality and reliability.[33] The ESCV considered that DNSPs should only pursue demand management initiatives where it was efficient to do so, and that any additional funding provided for such initiatives should be linked to beneficial outcomes for customers.[34]

The Victorian regulatory framework allows DNSPs to recover all demand management implementation costs out of the cost savings arising from capital expenditure deferral.[35] Where deferral benefits are accrued during a regulatory period, cost savings are fully retained by distributors and are available to cover demand management implementation costs.[36] The ESCV made a provision for demand management initiatives of $0.6 million in each DNSP's opex budget to provide additional revenue for the trial of demand management initiatives in the 2006–10 regulatory control period, to offset potential disincentives to use of demand management across regulatory periods.[37] The ESCV did not intend DNSPs' pursuit of demand management to be limited to the value of this provision. DNSPs are required to provide an annual report to the ESCV detailing the demand side activities that have been undertaken and their progress.[38]

The ESCV mandated an Interval Metering Rollout (IMRO) program in the 2006-10 EDPR. It considered that the IMRO may address the level of barriers to the implementation of demand management and non-network solutions[39] because the IMRO program would allow efficient non-network solutions to be more easily identified by DNSPs, and would also allow consumers of electricity to better respond to improved price signals. However, in November 2006 the Victorian Government decided to implement a mandatory Advanced Metering Infrastructure (AMI) program to replace IMRO with 'smart meters' with remote reading and remote switching facilities. AMI is a new technology and is expected to provide better information to consumers, DNSPs and retailers. It was decided that it would be more efficient for AMI to be rolled out gradually, than for IMRO to take place as planned. This process was proposed to begin in early 2008, however changes to AMI specifications and

33 ESC, *Electricity Distribution Price Review 2006-10 Final Decision* October 2006, p. 492
34 ibid., p. 502.
35 ibid., p. 495.
36 ibid., p. 496.
37 The benefit for the DNSPs of demand management may not accrue in the same regulatory control period in which the demand management projects are implemented, 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.
38 ESC, *Electricity Distribution Price Review 2006-10 Final Decision* October 2006, p. 502.
39 ibid, p.493

pricing has meant that the mandated roll-out of AMI is now scheduled to commence from the end of 2008.[40]

Based on IPART's assessment that the D-factor will provide 'relatively generous incentives with positive revenue outcomes for distributors' and that the effectiveness of the D-factor could not be fully assessed at the time of the 2006-10 EDPR, the ESCV considered that the D-factor would generate higher consumer prices that, with regard to the incentives in question, were not appropriate in Victoria at that point in time.[41] The ESCV recognised that the WAPC may have perceived disincentives for demand management.[42] However, the ESCV's final determination noted that while IPART's decision to incorporate a D-factor into the WAPC formula was to introduce incentives for a more active pursuit of demand management, the current focus in Victoria was on the removal of barriers in the regulatory framework that impeded demand management.[43] The ESCV considered that the roll out of interval meters[44] and the provision of $0.6 million for each DNSP would assist in removing the impact of such perceived barriers to demand management.[45] The ESCV also viewed distribution tariffs as a more effective and efficient method to manage rising demand.[46] The availability of information to inform tariff-based demand management strategies was regarded as a key benefit of this initiative.

3.6 Tasmania

The Office of the Tasmanian Energy Regulator did not incorporate specific demand management incentives in its price determination for Aurora Energy.

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40 Standing Committee of Officials of the Ministerial Council of Energy, *Cost-Benefit Analysis of Options for a National Smart Meter Roll-Out (Phase Two – Regional and Detailed Analyses)*, Regulatory Impact Statement, April 2008, p. 17.

41 ibid., p. 500.

42 ibid., p. 494, 495.

43 ibid., p. 499.

44 ibid., p. 493.

45 ibid., p. 496.

46 ibid.

4 Options for DMIS in QLD and SA,

4.1 Introduction

This section makes some preliminary assessments of the options available to the AER in developing DMIS to apply to QLD and SA DNSPs over the 2010–15 regulatory control period. The AER is seeking comments from stakeholders on the applicability of the following options to the QLD and SA DNSPs.

4.2 Demand management innovation allowance

Should the AER decide to apply a DMIS to QLD or SA DNSPs for the 2010–15 regulatory control period, a form of the demand management innovation allowance applied in the ACT and NSW may be appropriate. The scheme is compatible with a range of control mechanisms, and as such it is not constrained by the AER's decisions on the forms of control to apply to QLD and SA DNSPs.

The demand management innovation allowance is a simple scheme with low administrative costs. It aims to encourage DNSPs to undertake broad-based and/or innovative demand management, which may provide long term benefits to both the DNSPs and network users. The demand management innovation allowance provides an incentive in addition to the existing and potential demand management initiatives, outlined in section 2.4. It is a modest scheme, and is provided on a 'use it or lose it' basis. Consequently, increases in customers' prices should be small.

As the demand management innovation allowance is aimed at generating incentives for innovative demand management projects, it may build upon and coordinate well with the existing projects currently being carried out in both states, such as Ergon Energy's Solar Cities project and Energex's Cool Change initiative, or with various demand management projects being carried out by ETSA Utilities. As SA is the highest peaking state in Australia, a broad–based scheme that targets general demand reduction across the distribution network, rather than specific areas, may be appropriate.

The form of the innovation allowance may need to be altered from that which was applied in the ACT and NSW to accommodate differences in forms of control for standard control services. For example, recovery of foregone revenue under such an allowance may not be appropriate under a revenue cap control mechanism. This is because DNSPs under a revenue cap control mechanism would still be able to recover revenue up to their established maximum allowable revenue.

4.2.1 Variations on the demand management innovation allowance

During the second round of consultation which the AER conducted prior to developing DMIS to apply to the ACT and NSW for the 2009–14 regulatory control period, the Clean Energy Council (CEC) made a submission to the AER containing a number of recommendations.[47]

[47] This submission is available on the AER's website, www.aer.gov.au, within submissions on the AER's December 2007 preliminary positions paper.

One recommendation was that the AER stipulate a minimum default annual expenditure on demand management over the regulatory control period, to be incorporated into the DNSP's price determination.[48] The CEC recommended that 1-2 per cent of DNSP revenue would be an appropriate minium expenditure amount. Should a DNSP fail to undertake this level of expenditure, the allocation would be recovered through a negative D-factor mechanism in the annual price setting process. The CEC submitted that this initial allowance would provide DNSPs with a funding base to build their demand management capacity, and would address the perceived risk and cash flow difficulties associated with the ex-post recovery schemes such as the D-factor and the demand management innovation allowance.

The AER considers that this recommendation is similar to the demand management innovation allowance, however the allowance would be provided up front, on an ex ante basis, and then reviewed ex post to determine any necessary adjustments. Similarly to the D-factor and demand management innovation allowance, this recommendation provides a financial demand management incentive on a 'use it or lose it' basis.

4.3 The D-factor

IPART's decision to apply a D-factor was made as a result of the introduction of the WAPC. In continuing the D-factor the AER recognised that there may be a need to balance incentives under a WAPC. As mentioned above in section 2.4, the AER is aware that different control mechanisms have the potential to create different incentives for DNSPs to conduct demand management. The AER has not determined the forms of control that will apply to QLD and SA DNSPs over the 2010–15 regulatory control period.

The NER require that in developing a DMIS, the AER must take into account the willingness of customers or end users to pay for increases in costs resulting from the implementation of a DMIS. Taking into account the existing and potential incentives for demand management within the regulatory framework, it is not clear whether such a positive incentive mechanism as the D-factor is appropriate for application in QLD and SA at the time of the 2010 determinations. Also, as the D-factor has only been in operation for a short period of time, there is currently insufficient information to determine its effectiveness and full impact.[49]

4.3.1 Variations on the D-factor

During the consultation process for the AER's development of DMIS to apply in the ACT and NSW 2009 distribution determinations, stakeholders' submissions suggested variations on existing schemes. Stakeholders' submissions expressed support for expanding the NSW D-factor mechanism to include recovery of the implementation costs and associated foregone revenue of broad-based, innovative demand management projects that do not target the deferral of a specific network augmentation. It has been suggested that such an expansion may include a cap, so that

[48] Clean Energy Council, *RE: Preliminary positions: Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009-2014*, pp 5-6 (www.aer.gov.au).

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

total cost recovery of broad-based demand management projects within the D-factor would be limited to a percentage of planned capex, to be determined by the AER.

Some benefits of variations on the D-factor include:

- it is a ‘use it or lose it’ mechanism, and as such will not have a large impact on customer prices without DNSPs also significantly increasing spending on approved demand management projects

- it may allow the AER some scope to increase the incentive for DNSPs to conduct demand management in the first few years of the regulatory control period by increasing the cap. This is considered beneficial as it may provide earlier signals to other DNSPs and the demand management market about projects that could deliver cost effective demand management options under the normal D-factor.

4.4 Recognition of demand management expenditure in forecast opex

In the current Victorian and SA determinations, the ESCV and the Essential Services Commission of SA provided allowances for demand management projects within DNSPs’ opex (see discussion in sections 3.3 and 3.5). In Victoria the ESCV provided $0.6 million for demand management initiatives in each DNSP’s opex. In South Australia, and the Essential Services Commission of SA allowed $20.4 million for demand management programs.

Under the NER, one objective of opex is to allow DNSPs to manage demand. As such, an allowance for expenditure on specific demand management initiatives could be provided as part of a DNSP’s opex at the time of making a distribution determination. For the AER to approve forecast opex for demand management, that forecast must satisfy the opex requirements in clause 6.5.6 of the NER.

Opex objectives

Clause 6.5.6(a) of the NER provides that a DNSP’s building block proposal must include a forecast of the total opex for the regulatory control period that the DNSP will require to achieve four prescribed objectives (opex objectives):

1. to meet or manage the expected demand for standard control services over that period

2. to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services

3. to maintain the quality, reliability and security of supply of standard control services

4. to maintain the reliability, safety and security of the distribution system through the supply of standard control services.

Opex criteria and factors

The AER must accept the forecast opex included in a DNSP's building block proposal if it is satisfied that the total forecast opex for the regulatory control period reasonably reflects the following criteria (opex criteria)[50]:

1. the efficient costs of achieving the opex objectives

2. the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives

3. a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

The NER specify a number of factors to which the AER must have regard in determining whether these criteria are satisfied.[51] If, having regard to these factors, the AER is not satisfied that a DNSP's forecast opex reasonably reflects the opex criteria, the AER must not accept the forecast opex in a DNSP's proposal.[52]

Opex approved in a distribution determination for demand management would, under the NER, be treated in the same way as any other category of opex. Any DMIS applied in a distribution determination would operate in tandem with such an allowance, and would not preclude the approval of opex where the requirements of clause 6.5.6 are satisfied. Approved opex for demand management would, of its nature, be provided on an ex-ante basis, as distinct, for example, from the demand management innovation allowance applied in NSW and the ACT, which provides for ex-post cost recovery.

50 NER, clause 6.5.6(c).
51 ibid., clause 6.5.6(e).
52 ibid., clause 6.5.6(d).

5 Request for submissions

The AER seeks submissions from interested parties regarding the potential for DMIS for DNSPs in QLD and SA for the 2010–15 regulatory control period. Interested parties are invited to make written submissions to the AER on the issues discussed in this paper by the close of business Friday, 16 May 2008. Interested parties that made submissions to the AER on the development of DMIS for the ACT and NSW DNSPs in late 2007 and January 2008 should note that the relevant comments provided in these submissions will be taken account of in the development of a draft DMIS for QLD and SA. However, these interested parties are invited to make additional submissions building upon or clarifying their earlier submissions.

In developing a DMIS, the AER must take into account the following factors:

- 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 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.

Having regard to these factors, the AER seeks submissions on the following issues:

1. What are the incentives and disincentives for QLD and SA DNSPs to undertake demand management?
2. Is it necessary to apply a DMIS in QLD and/or SA, given the likely effect on customer prices and customer willingness to pay for an incentive for a DNSP to conduct demand management?
3. Do particular control mechanisms, such as tariff basket, revenue yield or revenue cap arrangements, create incentives or disincentives for DNSPs to undertake demand management?
4. Are DNSPs able to offer efficient pricing structures, and how does this effect the need for a DMIS?
5. Do lessons learned from the QLD or SA jurisdictions or other jurisdictions provide any insight into the potential development of DMIS to QLD and SA DNSPs?
6. How do DMIS interact with other incentive schemes, such as efficiency benefit sharing schemes, or service target performance incentive schemes?

7. What is the optimal structure of a potential DMIS for DNSPs in QLD and/or SA, and what impact is this structure expected to have on the efficiency of DNSPs' decisions?

8. What are the likely costs and benefits of implementing and administering the DMIS proposed in this paper or any other potential DMIS?