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SUBMISSION

to

AUSTRALIAN ENERGY REGULATOR

on

NSW Distribution Network Service Providers Proposals

2009 - 20014

August 2008

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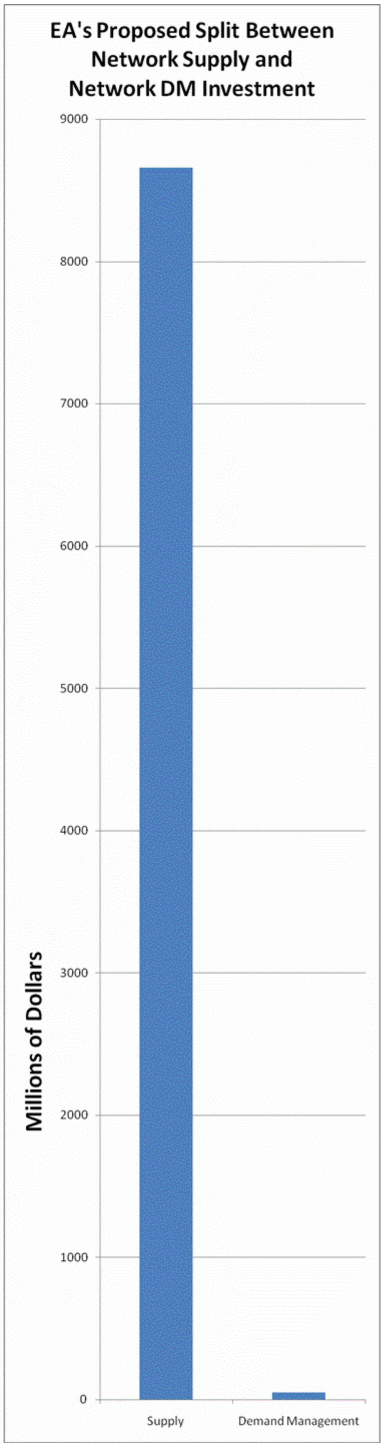
1. Inappropriate and inefficient level of DM



Total Environment Centre is concerned that the three NSW distribution networks have vastly under-utilised the potential of demand management (DM) to meet demand and have instead opted for an inefficient, peak-driven, asset-base expansion program.

The under-utilisation of DM is both inefficient and irresponsible in the context of NSW's spiraling greenhouse emissions, driven largely by the supply of carbon intensive electricity. The failure to implement large-scale DM is a lost opportunity for the least expensive greenhouse emissions reductions – energy efficiency and demand management - and places the inappropriate burdens of climate change and increased carbon costs on present and future generations.

Energy Australia's (EA's) proposal stands out for its excessive claim for $8.6 billion of capex compared to a mere $23 million, or 0.26%, for DM. Even if one compares solely the proposed peak demand related claim for $2.5 billion to proposed DM (p.55), the proportion is still vastly inappropriate, at a mere 0.9% of total peak demand driven spending. The graph to the left is a visual illustration of the paucity of EA's plans for DM.

Integral Energy's and Country Energy's proposals have failed to even provide projected expenditure on DM, and Integral's Appendix containing its DM plans is 'confidential' and unable to be assessed. This is unacceptable and further undermines confidence in Integral's proposal.

The failure of NSW distribution networks to utilise an adequate amount of DM has been recognised for many years. In 2004 the NSW Independent Pricing and Regulatory Tribunal (IPART) noted that the practice of addressing increasingly peaky demand with more augmentation has resulted in reduced asset utilisation, increased capex, reduced efficiency and impacts on end users.[1] As IPART noted, 10% of EA's network is used for 1% of the time.

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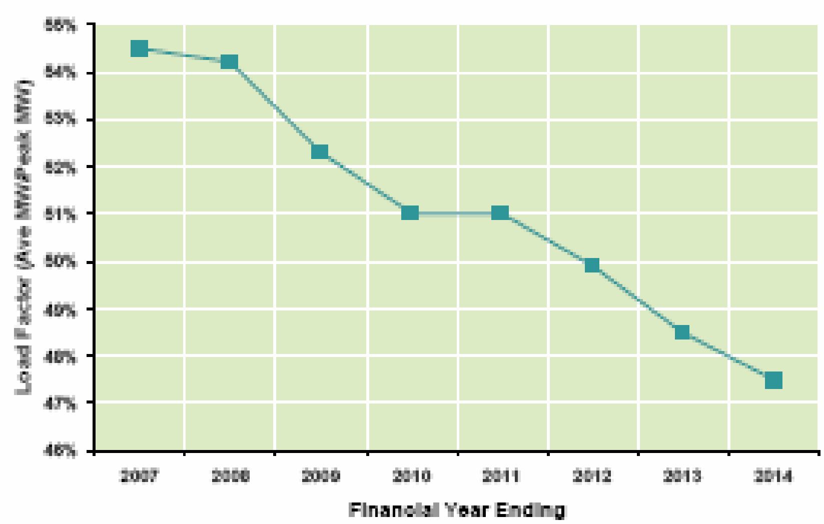
[1] IPART, *Final Report on NSW Electricity Distribution Pricing: 2004/05 to 2008/09*, June 2004 ,p. 89

Little has changed since 2004 despite the D-factor incentive scheme. Indeed, after five more years of little additional DM and an overwhelmingly supply focused approach, load factors are as bad as ever.

Integral Energy's load factor projection to 2014 (p., 72) below confirms that networks are becoming less efficient as regulators continue to sit on the side-lines and allow networks to continue to ignore DM.

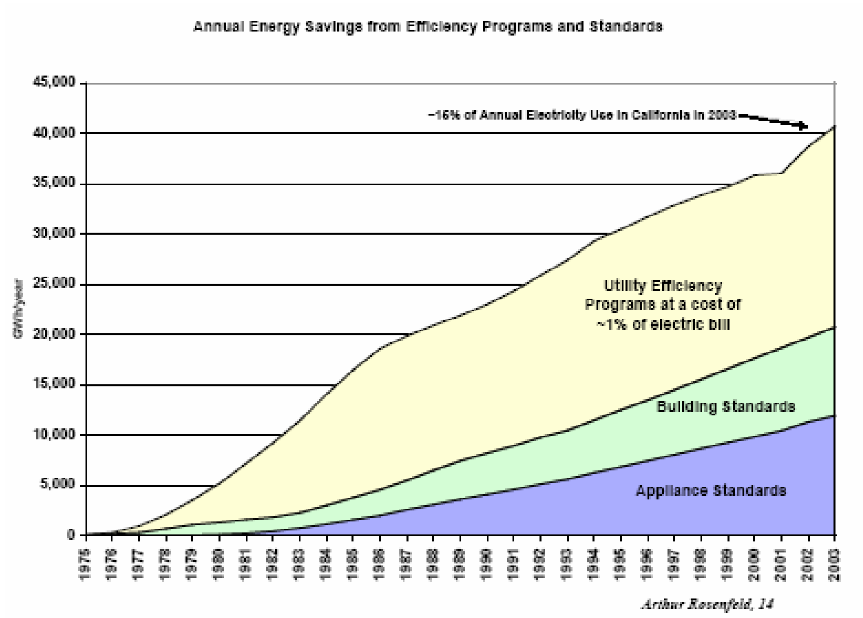
Figure 7.2: Integral Energy system load factor

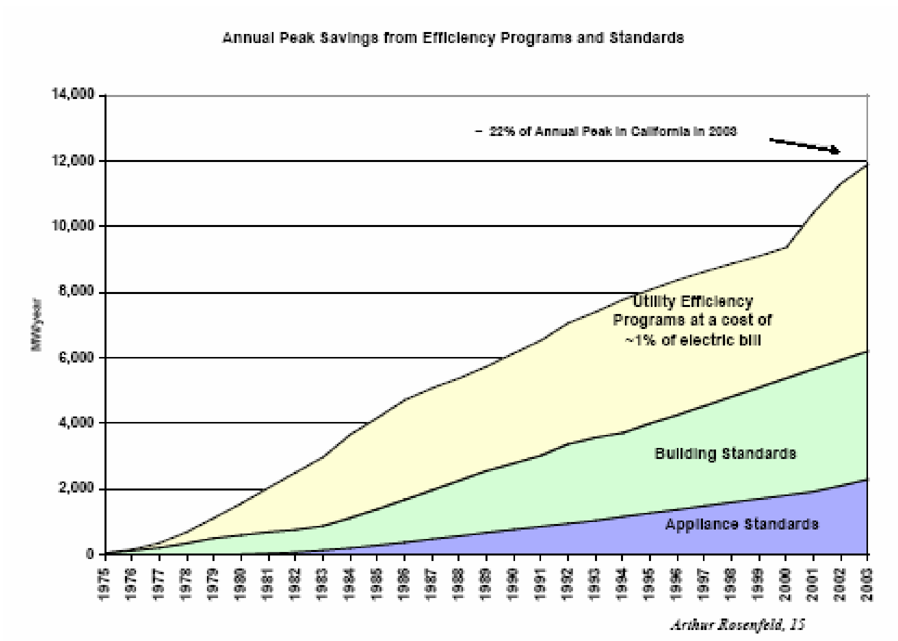


EA's proposal shows that the majority of new demand occurs at peak times making DM the most cost-effective approach, as it designed to reduce this peak demand. In addition, the growth in average demand in the non-residential sector makes energy efficiency appropriate and could readily be carried out by energy efficiency providers working on behalf of the networks.

The graph below from EA's proposal (p.43), demonstrates that peak demand is growing at almost double the rate of average demand.

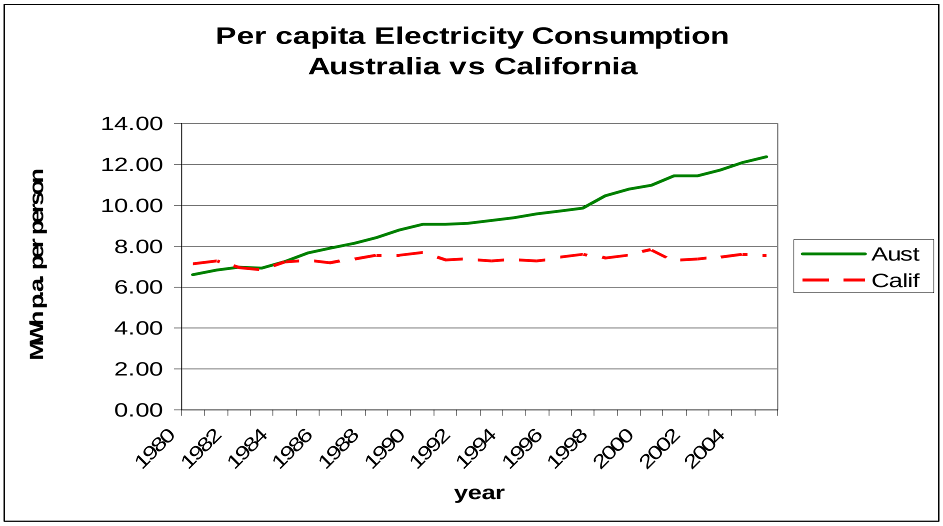
The experience of utility regulation in California has, in contrast to the NSW effort, been vastly more successful in stimulating utility-driven DM. The graphs below show how Californian regulators have ensured that utilities have secured peak reductions of 6000 MW per year and reduced overall electricity consumption by around 20,000 GWh per annum or about 7% of total electricity consumption.[2]





[2] Arthur H. Rosenfeld, Commissioner California Energy Commission, *Energy Efficiency in California – Some Possible Lessons for Ontario*, 20 March 2006, p. 14.

The reductions achieved in California are in stark contrast to Australian (including NSW) per capita electricity demand, which has continued to rise by 70% between 1980 and 2005.



Source: ISF, p. 23.

2. DM and energy efficiency more cost-effective

It is the responsibility of the Australian Energy Regulator (AER), acting in the long term interests of consumers, to ensure that the most cost-effective solution to meeting demand growth is selected by the networks. DM is by far the most cost-effective approach, despite its under-use by the networks. DM's cost-effectiveness is further enhanced when compared to the carbon costs payable by consumers that will continue to rise, particularly after the introduction of the Carbon Pollution Reduction Scheme.

Of the DM that has been undertaken in the last few years in NSW, it has achieved a benefit to cost ratio of 3.8:1.[3] As the TEC commissioned and Advocacy Panel funded report on the D-factor by the Institute for Sustainable Futures (ISF) notes:

> This suggests that there are very significant further cost-effective DM opportunities that have yet to be tapped.

The ISF report is attached to this submission as an appendix.

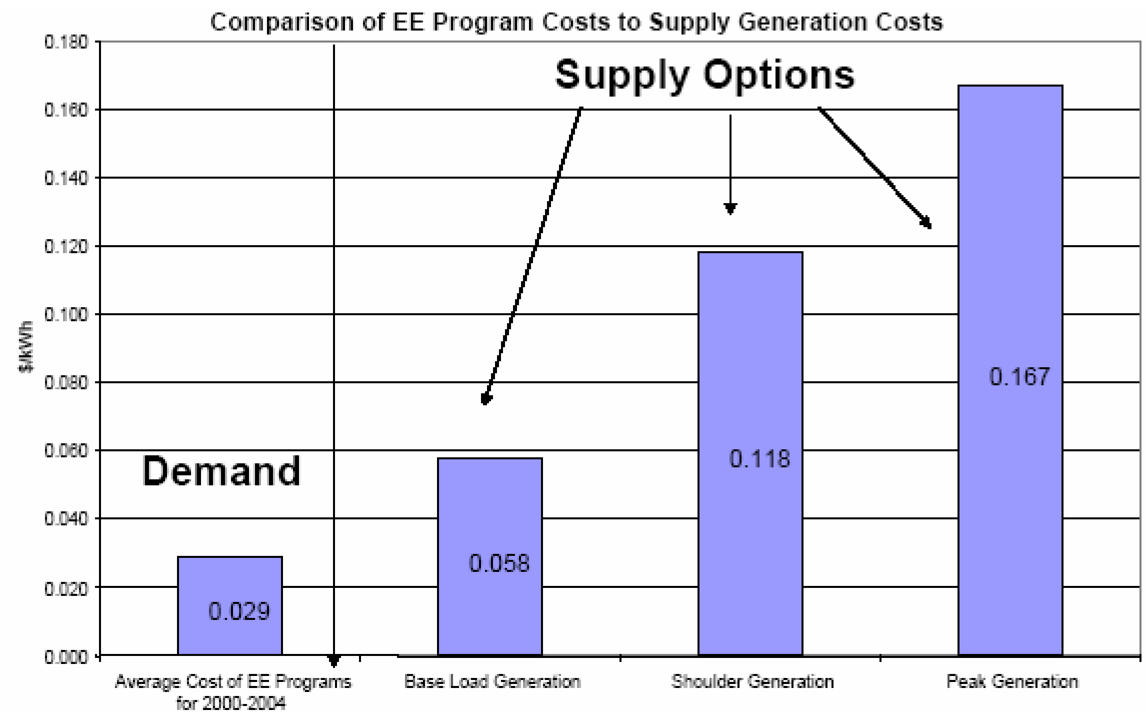
IPART has noted that the cost of providing distribution peak load can be around 400 times

[3] Institute for Sustainable Futures, *Win Win Win: Regulating Electricity Distribution Networks for Reliability, Consumers and the Environment - Review of the NSW D-Factor and Alternative Mechanisms to Encourage Demand Management*, January 2008, p. 5.

the cost of base load.[4] This makes a DM approach for peak driven demand growth the sensible approach for NSW networks. As IPART has pointed out, DM can have a significant impact on energy prices:

> Measures targeted at peak loads (such as interruptible contracts) will principally flatten the top of the load duration curve and tend to lower peak prices, and improve asset utilization. Together, these effects are likely to lower average energy prices. Energy efficiency measures of similar magnitude that act continuously will lower peak loads and defer capital expenditure. While it may not achieve better asset utilisation, the reduced energy usage can reduce participating customers energy bills directly.[5]

Confirming IPART's and the ISF report's findings, experience from utilities in California show that energy efficiency programs are vastly more cost-effective than supply options. The graph below illustrates the relative costs of generation versus demand management options.[6] As network augmentation costs are additional to these costs, it holds that the cost-effectiveness of DM compared to network *plus* generation costs is even greater.



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[4] IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report*, October 2002, p. 6.
[5] IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report*, October 2002, p. 6.
[6] Arthur H. Rosenfeld, Commissioner California Energy Commission, *Energy Efficiency in California – Some Possible Lessons for Ontario*, 20 March 2006, p. 21.

2. The D-factor

The utilisation in the previous regulatory period of the 'incentive' mechanism for DM, the 'D-factor' shows that this approach has largely failed to incentivise a more appropriate level of DM. While DM activity has increased marginally, it still languishes as an afterthought for the networks, rather than being elevated as the priority response. Indeed, despite the generous allowance by regulators for networks to recover the cost of DM in addition to foregone revenue, the D-factor has only resulted in reductions equivalent to 7% and 3% respectively of the average annual growth in summer peak demand in NSW in 04/05 and 05/06 respectively.

As the ISF report concluded:

> …the D-factor is not a cure-all for DM and, ***without reform and complementary measures, it is very unlikely to deliver an efficient level of DM activity***.[7] (italics and bold added)

It is clear that networks need more than soft incentives such as the D-factor to achieve an efficient level of DM. The AER must implement aggressive rewards and penalties to ensure that the networks transform themselves from infrastructure supply corporations to energy service providers with energy efficiency and DM as their priorities. The reforms and complementary measures recommended by the ISF report to achieve a more appropriate level of DM are outlined in section 3 below.

2. Regulatory bias against DM

The NSW network proposals point to the failure of network regulations to sufficiently incentivise DM. TEC has recently commissioned a major report with the assistance of the Advocacy Panel which investigates the type and depth of regulatory disincentives to network DM. The report, "Does current electricity network regulation actively minimise demand side responsiveness in the NEM?" identifies chronic, deep rooted and multi-faceted barriers to DM in regulation that is otherwise perceived as 'neutral'.[8] This report is also attached as an appendix to this submission. The major disincentives to DM inherent in current network regulation are outlined below.

2.1 The building block approach

2.1.1 The rate of return of capital (WACC)

This approach has embedded in it all of the base profit that the network receives for providing the service. Compared to this, the allowance for opex is provided for only at cost, and does not include any profit to the network for spending on any element included in the opex allowance. As many DM programs are opex based rather than network based, as the EA

[7] ISF, p. 5.
[8] Headberry Partners and Bob Lim & Co, *Does current electricity network regulation actively minimise demand side responsiveness in the NEM?,* Prepared for Total Environment Centre, June 2008

proposal notes[9], there is an active disincentive embedded in the building block approach against DM.

2.1.2 Ex-ante approach

The ex-ante capex program provides networks with the ability to spend capital within the regulatory allowance, but with no subsequent assessment of its economic efficiency or prudency. This provides no oversight to ensure the network has implemented DM when equal to or more cost-effective than augmentation.

2.2 Incentive schemes

2.2.1 The service performance incentive scheme

Amongst networks there is a recurring assertion that DM has implicitly less reliability than a network solution. Although these claims have not been substantiated by evidence, familiarity with network approaches, combined with the performance incentive scheme, results in the favouring of network approaches over non-network solutions.

On the basis that network solutions are perceived to provide a higher reliability than non-network solutions, the performance incentive scheme incentivises network solutions, as the network is required to take the risk (pay a penalty) if the performance is worse than the target, and is rewarded if performance is better than targeted. Thus a side-effect of the performance incentive scheme is to discourage DM solutions by actively encouraging the approach that is perceived to be more reliable: that is, the use of network approaches.

2.2.2 The Efficiency Benefit Sharing Scheme (EBSS)

The purpose in applying the EBSS is to incentivise the network to spend less opex than has been allowed in the revenue reset. In principle, this approach encourages networks to operate at the level of opex that is most economically efficient. The downside of this incentive scheme, however, is that any program that is included in the opex (such as DM) and which can be addressed in another way (such as network augmentation) provides an incentive for network solutions over DM.

2.3 Price caps versus revenue caps

Once revenue is determined under a price cap form of regulatory recovery, the network develops a set of tariffs which in theory will recover the allowed revenue based on the demand and consumption expected in the network over the regulatory period. If the demand and consumption vary then the network accepts the risk and/or benefits for such variation. This leads to the situation where any approach which is likely to reduce the total amount of electricity carried by the network will be considered by a network to be against its commercial

[9] EA, *DM Impact on 2009-14 Capital Forecast (Attachment 5.13 of EA's proposal)*, p. 5.

interests. A price cap therefore incentivises the network to increase demand and consumption of electricity to raise its profitability, and to reduce unit costs to consumers, and is therefore a strong disincentive against DM.

The revenue cap, in contrast, appears to be more neutral to DM, notwithstanding the inbuilt disincentive to DM in the building block approach. This is because a revenue cap form of regulated recovery merely requires the network to develop a set of tariffs which will return the allowed amount of revenue. Tariffs change from year to year to allow the network to recover the allowed amount of revenue and this insulates the network from any variation in demand or consumption within the network. A revenue cap, therefore, of itself does not incentivise or disincentivise the network to provide DM approaches.

3. Proactive regulation on DM urgently required

The conclusions of the Headberry/Lim paper along with the historic underutilisation of DM and the current supply-heavy proposals give weight to the case for sweeping changes to regulation to change network culture and dramatically increase the amount of DM being undertaken.

As the ISF report notes, NSW networks spend a fifth of the average spending by US utilities on DM, and even less when compared to the best performing US utilities.[10] Below are a range of approaches that have been proposed to ensure that a more appropriate level of DM is utilised by NSW networks.

3.1 ISF recommendations [11]

1. **Clarify government policy intent regarding efficient Demand Management**

In recognition of the scope of demand management (DM) both to advance the long-term interests of consumers and to enhance environmental sustainability, State, Territory and Federal Governments should ensure that the National Electricity Law and the National Electricity Rules:

- explicitly require the Australian Energy Regulator (AER) to make efficient regulatory determinations in relation to DM
- explicitly require Distributors to undertake all cost-effective DM, prior to network augmentation.

[10] ISF, p. 6.
[11] ISF, pp. 7-10

2. **Align network incentives with consumer and public interest**

In making regulatory determinations, the AER should avoid creating incentives that set the financial interests of the Distributors in conflict with the interest of their customers. In particular, incentives against DM should be avoided in relation to:

- short-term incentives (within regulatory periods) associated with price/revenue control formulae (see Recommendations 3 to 8)
- long-term incentives (between regulatory periods) associated with prudence review and the incorporation of capital expenditure into the capital base and mechanisms for sharing efficiency benefits between shareholders and consumers (see Recommendations 9 to 11)
- network system development and planning requirements (see Recommendations 12 and 13).

3. **“Decouple” Distributor profit from electricity sales**

In setting its year-to-year price control formula, the AER should as a key priority, decouple Distributor revenue and profit from electricity sales volume. That is, the AER should ensure that the profitability of a Distributor is not linked to the amount of electricity carried through its network and consumed by its customers.

4. **Use Revenue caps to decouple network profit from electricity sales**

In order to decouple electricity consumption and Distributor revenue and profitability, the AER should apply a revenue cap in preference to a price cap in regulating Distributors.

5. **Link revenue cap to economic growth**

In applying a revenue cap, the AER should consider applying adjustment factors to insulate Distributors from large divergence of actual peak demand from forecast peak demand. This could, for example, be applied by linking the annual revenue cap to movements in measures of economic activity, such as Gross State Product.

6. **Use D-factor if revenue cap precluded**

In circumstances where it is not possible to apply a revenue cap (for example, where a commitment to a price cap has already been made, as in NSW for the forthcoming regulatory period), other revenue decoupling or “lost revenue adjustment” mechanisms should be applied (such as the NSW D-factor).

7. **Create a “use it or lose it” component in the D-factor**

Where a “lost revenue adjustment” mechanism (such as the D-factor) is established, it should be applied with a default ex ante allocation on a “use it or lose it” basis that assumes some (non-trivial) level of DM will be undertaken by the Distributor. A D-factor of at least 2% of annual proposed capital expenditure could provide a reasonable default ex ante allocation.

8. Allow recovery of long-term DM costs in D-factor

Distributors should be permitted to recover, through the D-factor, costs associated with low cost "long-term DM" opportunities that would otherwise be lost if they are delayed until a local network capacity constraint emerges.

9. Allow Distributor savings from DM to be carried forward

The AER should ensure that Distributors are permitted to carry over efficiency benefits from DM, such as deferral or avoidance of capital expenditure, from one regulatory period to the next, on no less favourable terms than they are able to continue to earn a return on network capital investment from one period to the next.

10. Ensure balanced prudence review of capital expenditure

Recognising that short-term incentives are likely to have little impact unless complemented by longer-term incentives, the AER should ensure that the review of prudence of past and projected capital expenditure involves a thorough all-sources assessment of the opportunities for deferring capital expenditure through DM, conducted by experts with a demonstrated balanced understanding of the theory and practice of DM.

11. Require Distributors to demonstrate efforts to procure DM

The AER should require Distributors to demonstrate that they have undertaken reasonable efforts to identify and procure cost effective DM, particularly in the context of anticipated network constraints and proposed new network investment. Such efforts should include DM direct offers to consumers, DM programs developed by the Distributor and DM proposals solicited from other parties.

12. Inform the DM market

The AER should seek to inform the market for DM options by requiring Distributors to publish detailed information annually about the current capacity of the distribution network, current and projected demand and possible options to address any emerging constraints. (The NSW DM Code of Practice for Distributors and the South Australian Guideline 12 provide sound precedents for such information disclosure.)

13. Ensure consistent Distributor DM performance reporting

The AER should require Distributors to report annually on DM activities undertaken in relation to: expenditure, peak demand and energy consumption reductions, value of electricity sales foregone, value of capital and operating expenditure avoided or deferred, and efforts to identify and procure cost effective DM. Such reports should be publicly available. The AER should issue a pro forma to encourage consistency in DM reporting. Reporting to the AER should be harmonised with any other DM reporting requirements.

14. Conduct and publish annual AER DM Reviews

In recognition of the relatively underdeveloped state of DM in Australia, the AER should monitor DM data provided by Distributors and publish a consolidated annual review to encourage mutual learning and allow comparison of different policies and approaches between jurisdictions. (This will also assist in building understanding of DM potential within the regulatory community and among stakeholders.)

15. Apply complementary transitional measures to accelerate DM

Recognising that the above measures are designed simply to address existing barriers to efficient DM in the economic regulatory environment, and that the DM market in Australia is currently underdeveloped, Federal, State and Territory Governments should establish complementary transitional measures to create positive incentives to develop DM quickly.

16. Put an appropriate price on greenhouse gas emissions

In the interests of economic efficiency, and in recognition of the high economic cost that climate change is expected to impose on the Australian and global community, the Australian Government should ensure that the price of greenhouse gas polluting activities, such as fossil fuel-based electricity generation, includes the full cost of the associated greenhouse gas emissions. This could be achieved by introducing an emissions trading scheme or a carbon tax. (Recommendations 1 to 14 would be complementary to such action.)

3.2 Headberry/Lim recommendations to remedy active regulatory disincentives to DM

On investigating various jurisdictions' approaches to overcoming inherent disincentives to DM, the Headberry/Lim report includes these recommendations:

1. Separate and parallel DM incentive schemes, established and overseen by regulators, are the most effective way of ensuring DM initiatives by network businesses.

2. The use of a revenue cap, removing the incentive for networks to increase demand and consumption, would be required in addition to DM incentive schemes.

3. Demand management programs for each network business might contain the following features:

    a. Identification of DM options and target outcomes, and establishment of a pact between regulators and network businesses

    b. Inclusion of a fixed amount of funding for DM to be included in the allowed revenue for the network business

c. Incorporation of a program of benefit sharing, and financial incentives and penalties

d. Implementation as part of the regulatory reset.

4. An overarching energy policy requirement should be set by government for actioning energy efficiency targets across the entire electricity supply chain.

3.3 TEC's Rule change proposal

Total Environment Centre's Rule change proposal echoes some of the recommendations above and is currently being considered by the Australian Energy Market Commission in relation to transmission networks, but equally to distribution networks. Below is a summary of the key recommendations from the proposal designed to ensure a more efficient network response to end user demand.

1. Transmission network planning

It is critical that regulators ensure that DM solutions are prioritised and properly investigated in the planning stages of network development.

2. Annual Planning Reports

Networks should be required to publish robust data on upcoming constraints that are relevant and useful to DM service providers. This would serve to inform the DM market of upcoming opportunities and enable it to respond to these in a timely manner.

3. DM Incentive

In recognition of the failure of networks to invest in cost-effective DM, there should be an explicit provision for the Australian Energy Regulator to develop and implement a demand side incentive scheme.

4. Financial cover for DM investments

The circumstances in which networks can recover expenditure on demand side activities needs to be clearly specified in order to create more certainty regarding the ability of networks to investigate, implement and recover DM expenditure.

5. Revenue determinations

It is necessary to prioritise DM activities above supply side approaches to ensure they are rightly ranked, properly investigated and integrated into revenue determinations.

6. Acknowledgment of modest DM expenditure

There needs to be explicit acknowledgement of the potential use and value of small scale demand side activities in covering relatively modest amounts of load or hours at risk. Modest demand reduction, unrelated to particular constraints, can provide long term benefits by reducing the need for a wide range of possible future network augmentations.

7. Effective prudency reviews

Prudency reviews that assess past capital expenditure should be undertaken, and conducted by experts with a demonstrated balanced understanding of the theory and practice of DM. These should specifically and thoroughly assess the extent to which networks have implemented DM and penalise networks for failing to implement the most cost-effective measures.

8. Regulatory Test

Currently, the provisions for the Regulatory Test do not include demand side options as a necessity in any assessment of costs or benefits. To reverse this bias, the Rules should specify that DM options must be investigated *before* augmentation options. This is likely to ensure that a more appropriate level of transmission networks' resources and attention are directed to DM before augmentation planning is underway.

9. Short-term and long-term price for DM

There is no mechanism is in place for setting the price of demand side response (DSR) activities within the market pool. Setting a price for DM will encourage greater investment in DM and facilitate growth of DM aggregation as a market commodity. A market mechanism that provides the opportunity for proponents to bid into the market would encourage new DM entrants; promote competition for existing DM businesses; and make the implementation of DM options easier for network businesses.

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6 November 2007

Dr John Tamblyn
Chairman
Australian Energy Market Commission
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Sydney 2000

Dear Dr Tamblyn,

Rule change proposal – demand management and transmission networks

We are pleased to present our package of Rule changes for your consideration.

The focus of the proposals is on correcting the major bias against demand management[1] (DM) in the National Electricity Market (NEM). Over many years, the Council of Australian Governments (COAG) and the Ministerial Council on Energy (MCE) have repeatedly expressed their support for DM but little has been done to address the very large incentives for inefficient investment and inefficient consumption of electricity.

The failure to harness an adequate level of DM is such a fundamental flaw of the NEM that broad-scale changes to the Rules are urgently required. Unnecessary pressures to build expensive new infrastructure inflate costs - decrease the efficiency and reliability of networks, destroy options for cost-effective DM and unnecessarily raise prices for consumers. These outcomes are in conflict with the long-term interests of consumers.

Through various forums, the Total Environment Centre (TEC) has been advocating for DM to become a primary focus for decision making about the National Electricity Market, in particular for incorporation of DM principles within the National Electricity Rules (the Rules). To counter the strong bias of networks towards inefficient augmentation, it is essential that cost-effective DM is the priority consideration for meeting energy demands *before* other options are considered. In this way, the market can truly serve the long-term interests of consumers through harnessing maximum efficiency.

[1] Demand management in this proposal can be read to include ‘demand response’, ‘demand side management’, ‘demand side response’, ‘energy efficiency’ and ‘non-network solutions’. In general, DM can include both the management of peak loads and energy efficiency as a way of meeting capacity requirements with the greatest cost-efficiency. It includes a diverse array of activities that meet energy needs, including cogeneration, standby generation, fuel switching, interruptible customer contracts, and other load-shifting mechanisms.

While our proposals directly address arrangements for transmission networks, the intention is that the same principles should also filter down to the Rules and future determinations for distribution networks.

Several parallel processes are currently occurring which are relevant to these proposals. We outline them in the body of the document and explain why the proposed changes still require urgent attention. At the very least, the preferential optimisation of DM should be the priority for matters to be addressed in any review of the Rules by the Australian Energy Market Commission (AEMC).

We look forward to the AEMC's and other stakeholders' responses. If there are queries about this proposal, please contact Jane Castle on 02 9261 3437.

Yours faithfully,

Jeff Angel
Executive Director

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Rule Change Package

Demand management and transmission networks

6 November 2007

Total Environment Centre acknowledges the support of the National Consumers Advocacy Panel in producing this proposal.

Contents

1 Introduction

Neglect of demand management (DM) is a pervasive problem throughout the National Electricity Rules, despite professed intentions that demand side options should be given “due and reasonable consideration”.[2]

While purporting to support equality of DM compared to other options, the Rules pay mere lip service to DM when compared to the massive incentives for inefficient supply side approaches.

This approach is resulting in inefficient, peak-driven transmission infrastructure investments at the expense of the long-term interests of consumers. Little has changed in this regard since the Parer report[3], which noted:

> *A key feature of competitive markets is the active participation of both the supply and demand sides. Without this, competition is blunted and the potential for the exercise of market power is enhanced…. Many submissions to the Review contended that demand side involvement in the NEM is under-developed.*

The failure to adequately cater for DM pervades the Rules which urgently need to be corrected for the NEM Objective to be met.

The insertion of a demand management objective in the National Electricity Law would be a significant fix for the DM problem at source. To this end, TEC and a range of community groups and the Clean Energy Council strongly advocate for insertion of demand management, environmental and social objectives in the National Electricity Law.[4, 5] TEC will continue to advocate for the inclusion for these objectives in the National Electricity Law.

DM Rules need to be established at the highest level in the NEM and should apply to transmission and distribution network regulation as well as regulations governing the operation of the spot (supply) market. This package of proposals, however, only deals with transmission network regulation and the spot market as the Rules for distribution networks are currently being re-drafted by the MCE’s Standing Committee of Officials (SCO). The current form of the newly drafted distribution Rules falls well short of countering the large incentive for inefficiency in the NEM, and we will be submitting further Rules change proposals to address these deficiencies at a later date.

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[2] For example, *6.2.3(d)(2)*

[3] Commonwealth of Australia, *Towards a Truly National and Efficient Energy Market*, 2002, p 173

[4] Total Environment Centre, Consumer Utilities Advocacy Centre, Business Council for Sustainable Energy, Australian Council of Social Services, WWF Australia, Australian Conservation Foundation, St Vincent de Paul Society, *Power for the People Declaration*, May 2007 at www.tec.org.au

[5] Total Environment Centre, Council of Social Services NSW, Queensland Consumers Association, WWF Australia, Conservation Council of South Australia, Climate Action Network Australia, Environmental Defenders Office NSW, Environment Victoria, ACT Council of Social Services, Alternative Technology Association, South Australian Council of Social Services, Australian Conservation Foundation, Moreland Energy Foundation, Public Interest Advocacy Centre, Nature Conservation Council of NSW, Tasmanian Council of Social Services, Tasmanian Environment Centre, Consumer Law Centre of Victoria, Queensland Conservation Council, Consumers Federation of Australia, *The National Electricity Market Amendment Package*, October 2004, at www.tec.org.au

2 Other NEM processes to address DM

2.1 DM as a Jurisdictional Direction

Once regulation of distribution becomes national, it has been proposed that "environmental issues" and consideration of demand side options be regulated according to jurisdictional requirements. Mechanisms have been proposed for dealing with these issues, the primary one being a so-called "Jurisdictional Direction". Gilbert+Tobin and NERA Economic Consulting created the term[6], and Clayton Utz is currently investigating a similar approach for the MCE's Retail Policy Working Group[7].

Leaving incentives for DM to the discretion of the jurisdictions is a poor substitute for responsible and truly national regulation for the efficient use of electricity. This approach continues the tradition of sidelining DM and grouping it with "environmental matters", with the implication and practical effect that it is not something to be actively pursued within the NEM. This is short-sighted at best, since DM can, and should be required, to be an integral component of an efficient and reliable electricity system, leading to reduced costs and reduced prices for electricity consumers.

The jurisdictional direction proposal is inadequate to meet the needs of the full and proper utilisation of DM in the NEM.

2.2 The Renewable and Distributed Generation Working Group

The MCE has a Renewable and Distributed Generation Working Group (RDGWG), but its area of investigation is not directly germane to this proposal. The RDGWG has produced an issues paper on a draft Code of Practice for Embedded Generation, to which we have responded (as an individual organisation and also with the Climate Action Network of Australia). In those responses we recommended that as many features as possible of the Code should be embodied in the Rules. Although we would consider renewable and embedded generation as part of the suite of non-network solutions, in this proposal we have focused on the embrace of demand management as a general principle for transmission networks. This work will be continued with the distribution framework development (see 2.5).

The new Rules on embedded generation are only a sub-set of the suite of DM tools and do not address the need to overhaul the rules to achieve the full and proper utilisation of DM in the NEM.

2.3 The Smart Meter Working Group

The MCE's Smart Meter Working Group (SMWG) is focussing on the national roll-out of smart meters (under direction from COAG) and it has established a Smart Meter Stakeholder Working Group (SMSWG). While smart meters may eventually send more accurate price signals to consumers, they are only a small part of DM, and without a significantly enhanced focus on DM in the Rules the full capacity of smart meters to facilitate load reductions is likely to be overlooked, and the price signals provided by smart meters may be merely absorbed by electricity consumers. Total Environment Centre has recently commissioned a report,

[6] Gilbert+Tobin and NERA Economic Consulting for the Standing Committee of Officials of the Ministerial Council on Energy, *Public Consultation on a National Framework for Energy Distribution and Retail Regulation*, May 2005.
[7] Referred to in the RPWG's Working Papers 0f 2006/2007.

Advanced Metering for Energy Supply in Australia, which has warned that without strong incentives for networks and retailers to utilise the demand reduction capacities presented by the meters, the meters may not provide any additional benefits.

The roll-out of smart meters is a small part of DM and without overhauling the Rules to require the preferential prioritisation of DM, they may do little to harness the full potential of DM.

2.4 Regulatory Test

We note that there is an intention to review the Regulatory Test in the context of a new national transmission planner. However, without firm guidance in the Rules on the priority of DM in relation to the Test, the outcome is likely to continue to favour inefficient ‘build’ outcomes at the expense of more cost-effective DM solutions.

Although the AER is responsible for the development of the contents of the Regulatory Test, there are directions in the Rules about its purpose and content. In theory, the Test could be used to address the problems we have raised in this proposal, but in practice it is rarely applied by the AER to promote non-network alternatives.

2.5 New distribution Rules

The MCE has recently released amendments to the National Electricity Law that transfer the regulation of distribution networks to the AER, accompanied by Rule changes, some of which are designed to reduce barriers to distributed generation and DM. Unfortunately, these fall short of what is required to ensure that DM is prioritised to deliver optimum efficiency. While the introductory analysis here refers to transmission and distribution networks, to give a fuller contextual picture, this Rule change package focuses on transmission networks. As a result, TEC will be submitting further Rule change proposals to address the distribution network regulation problems.

2.6 New National Energy Market Operator

We note that COAG, at its meeting on 13 April 2007, has decided to establish a Australian Energy Market Operator to manage both electricity and gas. It is intended that this body’s responsibilities will be expanded beyond that of the existing National Electricity Market Management Company (NEMMCO) and also include a national transmission planning function (such as developing a preliminary then annual National Transmission Network Development Plan).

It is critical that overarching principles for the preferential optimisation of DM are embedded in the planning function of this or any similar body, and some of the following Rule proposals would need to be adopted by such a new body.

2.7 AEMC’s Review of Demand Management

The AEMC has announced via its website that it will be reviewing the potential “to better facilitate demand side participation” in the NEM. While long overdue, this is a promising development. The need to address DM is so urgent, however, that the review should not in any way delay the progress of the Rule changes proposed here.

The major focus of Stage 1 of the AEMC's review will be assessing the intersection between demand side participation and other national work streams, including the Congestion Management Review, the Reliability Panel's current review and the development of the National Transmission Planner. TEC has previously made submissions on all the aforementioned reviews, and will continue to participate in them in the future. We will also participate in this new review.

Of greatest interest to TEC in this new AEMC review is due consideration of the optimisation of demand management as a factor in demand side participation.

3 Background

3.1 Benefits of demand management

Definition of demand management

We understand demand management to include ‘demand response’, ‘demand side management’, ‘demand side response’, ‘energy efficiency’ and ‘non-network solutions’. In general, DM can include both the management of peak loads and base-load. It includes a diverse array of activities that meet energy needs, including cogeneration, standby generation, power factor correction, fuel switching, interruptible customer contracts, demand side aggregation, including through the use of smart meters, and other load shifting mechanisms.

National Electricity Market Objective

Section 7 of the National Electricity Law states the National Electricity Market Objective is as follows:

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

The NEM Objective provides high-level assessment criteria that allow for the inclusion of a wide range of market potentials. Despite specifically highlighting the ‘efficient investment in, and efficient use of, electricity’, thus far demand management has not been central in the application of the Objective and development of the Rules.

Efficiency

Economic efficiency is central to the NEM and to achieve this there must be a renewed emphasis on DM. Transmission and distribution networks, in practice, are natural monopolies and therefore lack natural incentives to carry out their operations in the most efficient manner, since there is a lack of competition to force efficiency. This places the responsibility for efficiency on the NEM Rules and on regulators. Under the current Rules, however, it is in the interests of network businesses to increase their revenue through the expansion of their asset bases, driven by inefficient consumption of electricity.

The NEM is focused on the inefficient expansion, rather than the avoidance of new infrastructure. At the very least, the issue of balance results from the fact that in the vast majority of cases, the process of evaluating alternatives is only raised once infrastructure proposals are under way, and are usually in an advanced stage of development. It is only then, if at all, that more cost-effective DM solutions are contemplated. The time allowed for adequate investigation of alternatives is then limited by the networks’ pre-determined timeframe, which may not be sufficient to allow for the planning and advancement of beneficial non-network solutions.

Despite the huge efficiency potential offered by DM, efficiency gains within the DM provider market itself are also hampered by artificially low requests for DM services. This reduces competition within that market and its ability to compete with supply side alternatives, resulting in reduced overall efficiency.

The AEMC has previously acknowledged[8] potential benefits arising from the development of demand management and other energy sources, that is, that by utilising these sources:

> *… transmission can avoid the need for, or can itself be avoided by, the development of local generation, DSM and non-electricity options. Therefore, transmission regulation and pricing should ensure transmission does not "crowd out" alternatives. The Commission considers it important for transmission regulatory arrangements to be structured in a way that ensures that there is an appropriate opportunity for alternatives.*

The specific contributions for efficiency flowing from the optimal use of DM include:

- deferred or prevented augmentation of transmission networks (avoided opex and capex);
- reduced requirement for expensive investment in generation (which further reduces the need for transmission augmentation);
- reduction of congestion – short and long-term;
- greater accuracy of pricing signals;
- creation of a more robust DM provider market;
- lower overall costs;
- lower prices; and
- increased reliability.

Reliability

"Reliability" is defined in the Rules Glossary as: "The probability of a system, device, plant or equipment performing its function adequately for the period of time intended, under the operating conditions encountered." DM techniques can offer both short and long-term supply and system efficiencies and hence assist system reliability. Overall reduction of consumption can relieve the burden on generation and the whole system, while direct load control and DM aggregation targeting peak demand can assist with short-term congestion. Due to their generally low cost, DM measures can be more efficient than supply-side investments to improve reliability.

The full realisation of the reliability benefits of DM is further undermined by the lack of firm short and long-term prices for demand-side response arrangements, which makes investment in it less attractive.

Long-term interest of consumers

The long-term interest of consumers would be served by greater efficiency, which would result in lower costs and prices, and increased reliability, leading to improved supply and fewer system failures.

Although the AEMC currently considers the reduction of greenhouse emissions immaterial to the long-term interests of consumers as defined by a narrow economic interpretation of the NEM Objective, and therefore outside its regulatory scope, TEC regards this position as untenable and subject to re-evaluation. Despite the current regulatory disconnect between the long-term interests of consumers as seen in a narrow economic sense and the broader

[8] Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules – Transmission Pricing: Issues Paper*, November 2005, p 32.

long-term interests of consumers, DM contributes to the long-term interests of consumers in the context of climate change by:

- reducing future carbon costs;
- avoiding wide-scale economic devastation, and;
- facilitating protection of the environment.

These are integral to meeting community needs. TEC is pursuing the issue, however, in other arenas and this proposal does not hinge on this argument.

The potential for DM in the NEM

There is a plethora of localised and generic studies that reflect the potential for DM in the NEM. This potential is sizeable. One recent estimate shows that DM potential is in the order of 3000MW.[9] However, TEC considers this estimate to be conservative as it fails to reflect all forms of DM available in the NEM. Including broad-scale energy efficiency measures, as outlined in the National Framework for Energy Efficiency[10], and programs specifically targeting the commercial sector, may provide potential of 4000-5000MW.

3.2 Barriers to demand management

Despite the numerous benefits of DM in contributing to better operation of the NEM and recognition of these by many agencies, it has been largely neglected within the National Electricity Rules. There is a common perception that networks do consider alternatives to network augmentation when these can provide the relevant services at a lower cost, but this is not borne out by an examination of the Rules themselves or in practice. It is clear that very little examination or implementation of non-network solutions is being undertaken. This is the case even for NSW distribution networks where, under a price cap, the Independent Pricing and Regulatory Tribunal (IPART) has implemented the “D-factor” incentive for demand management. A review of the ‘D-factor’ recently commissioned by TEC bears this out.[11]

Energy efficiency is being promoted in some arenas across Australia outside the NEM[12] but DM in all its forms is not being addressed within the market itself. It is often argued that energy efficiency programs should be undertaken outside the market in the form of policies and programs established by the jurisdictions (including the Commonwealth), but there are nonetheless multiple intersections with the NEM in which the NEM effectively dampens or blocks these programs. Moreover, as they remain outside the NEM, these policies and programs are subject to change at any time. If efficiency in the use of electricity is an objective of the National Electricity Law, then DM and energy efficiency should be integrated within the Rules, rather than being discretional extras dependent on the jurisdictional governments and policies of the day.

[9] KPMG for Energy Reform Implementation Group, *Review of Energy Related Financial Markets,* November 2006, p. 101

[10] National Framework for Energy Efficiency, *Towards a National Framework for Energy Efficiency Issues and challenges: Discussion paper*, Energy Efficiency and Greenhouse Working Group (MCE), November 2003.

[11] Institute for Sustainable Futures, *Win, Win, Win: Regulating Distribution Networks for Reliability, Consumers and the Environment – A Review of the NSW D-Factor and Alternative Mechanisms to Encourage Demand Management*, Draft Report, forthcoming.

[12] For example, within the NSW Greenhouse Gas Abatement Scheme.

Specific barriers to the uptake of DM by transmission networks which arise from deficiencies within the Rules include:

Planning

1. A major issue is the planning processes that transmission networks are required to undertake according to the Rules. Currently, transmission networks are not required to solicit proposals for DM solutions before deciding to augment their networks. This reinforces a cultural barrier to more cost-effective DM solutions.

2. There are insufficient incentives for transmission networks to pursue DM and the resulting unfamiliarity has led to the perception that DM is more risky which creates a barrier in itself. The standard approach is often considered simpler than pursuing an option that, even if it may be more cost effective, is not regarded as "normal" within mainstream network management. This probably represents the greatest barrier to the uptake of DM – that it is generally not regarded as a viable alternative since it is outside standard practice, and currently virtually outside the Rules as well.

3. Current approaches for assessing the cost-effectiveness of DM in network applications, on the rare occasion that they are actually assessed, generally require that the deferral value exceed the total cost of the DM option.[13] This fails to take into consideration the potential of the same DM activity, as well as modest DM expenditure, to contribute to the deferral of subsequent augmentations.

Information

4. There is a lack of specific requirements for the provision of information to enable DM prospecting for network deferral. The information provided as part of the consideration of DM options generally falls short of what is required in terms of timeliness and specificity, thus creating a barrier to potential investment. Clause 5.1.3 (f) (2) is very general and ineffectively requires "open communication and information flows relating to connections between Registered Participants themselves …". DM providers need comprehensive and timely information to ensure that DM proposals have a reasonable likelihood of serious consideration.

5. There is a mismatch in the timeframes for considering DM and supply-side investments for networks, since information on network needs is often provided based on the timelines required for network augmentations rather than also being applicable to DM. This often poses insurmountable constraints to the development of a DM solution. This problem is compounded by the networks' current unfamiliarity and lack of expertise with DM.

Regulation

6. The lack of certainty about when and under what circumstances transmission networks can recover DM expenditure is hindering transmission networks' propensity to properly investigate and implement DM. While there is extensive detail on the recovery of

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[13] For example, as set out in *Demand Management for Electricity Distributors NSW Code of Practice,* NSW Department of Energy, Utilities and Sustainability, September 2004, pp 22-23.

expenditure in the transmission networks' regulated asset base, there is scant detail on how a transmission network is to recover expenditure on demand side activities.

7. There are split incentives for DM since the benefits can flow to different markets and therefore potentially to different beneficiaries. Implementation by any party unable to access all the relevant markets reduces the value of the DM measures, and therefore the amount that will be obtained. There is no mechanism requiring market participants to cooperate in considering or implementing DM and so re-aggregation rarely occurs.

8. The absence of either a firm short or long-term price for DM is a critical flaw in the market. The fact that energy prices in the wholesale market can change at short notice makes advance notification of the value of DM difficult and therefore its use more challenging than other transactions. However greater experience in the application of DM mechanisms will assist with making its value more apparent. The lack of longer-term prices inhibits the potential for capital investment to optimise the amount of DM, as well as increasing transaction costs for retailers and DM aggregators.

9. In regard to small customers, investment in DM can present a risk in the form of high transaction costs overall as well as the potential for the stranding of assets if the DM results are lower than expected. Current regulation presents barriers in this case because of inadequate consideration of DM investments, thus reducing the potential for DM actions for these customers. This is exacerbated by the capital costs required to enable price response. These drawbacks thus require an adequate means for cost recovery of the investment in the asset.

Further barriers and elaborations are found below in specific Rule change proposals.

3.3 Existing Rules content

The overarching problem is that DM (otherwise referred to in the Rules as “non-network solutions”) is virtually ignored within the Rules, even considering the latest proposed changes to the Chapter 6 Rules for distribution networks, mentioned above. There seems to be a general perception that the few mentions are active concepts within the Rules, but closer inspection reveals only the following references[14]:

- *Demand management:* Glossary – regarding medium term capacity reserve; restriction of demand reduction; short term capacity reserve; statement of opportunities (regarding demand management capacity).

- *Demand side* (in terms of DM): 5.6.2f the relevant Distribution Network Service Provider must consult … on the possible options, including but not limited to demand side options, generation options …

  5.6.2A(b)(4)vi (regarding Annual Planning Reports): Other reasonable network and non-network options considered to address the actual or potential constraint or inability to meet the network performance requirements … Other reasonable network and non-network options include, but are not limited to, interconnectors, generation options, demand side options …

  5.6.5A(c)(4) require, for a potential new large transmission network asset, the that Network Service Provider publish: (i) a request for information as to the identity and detail of alternative options to the potential new large transmission network asset;

  5.6.5 Annual National Transmission Statement reviews: (c)(7) possible scenarios for additional generation and demand side options to meet demand forecasts;

  5.6.6 regarding new large transmission assets: (a)(iii) all other reasonable network and non-network alternatives to address the identified constraint or inability to meet the network performance requirements … These alternatives include, but are not limited to, interconnectors, generation option, demand side options …

  6.2.3 Principles for regulation of transmission aggregate revenue: (d) The regulatory regime to be administered by the AER … must also have regard to the need to: (2) create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration;[15]

  6.10.3 Principles for regulation of distribution service pricing: (e) The regulatory regime to be administered by the Jurisdictional Regulator … must also have regard to the need to: (2) create an environment in which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration;

  6.10.3 (d) in setting a separate regulatory cap … the Jurisdictional Regulator must take into account each Distribution Network Service Providers (7) (iii) payments made to Embedded Generators for demand side management programs …

[14] These quotes refer to the electronic Version 13 of the National Electricity Rules of 15 March 2007.
[15] This and other Chapter 6 Rules may be deleted subject to recently proposed Rule changes.

5.5 Embedded Generation: Embedded Generators can in some circumstances provide significant benefits in certain parts of a distribution network. An example will highlight some of the issues. … The options to be considered in this case include: … a demand side management project incorporating both curtailable and interruptible loads;

- *Non-network*, extra to above: 5.6.2 Network Development: (c) Where the necessity for augmentation or a non-network alternative is identified by the annual planning review … the relevant Network Service Providers must undertake joint planning …

  5.6.2 (e) the expected time required to allow the appropriate corrective network augmentation or non-network alternatives …

  5.6.2A(b)(4)vi (regarding Annual Planning Reports): other reasonable network and non-network options considered to address the actual or potential constraint or inability to meet the network performance requirements identified in clause 5.6.2A(b)(4)(ii), if any. Other reasonable network and non-network options include, but are not limited to, interconnectors, generation options, demand side options, market network service options and options involving other transmission and distribution networks.

  5.6.2A(b) 5 (regarding Annual Planning Reports): for all proposed new small transmission network assets: (i) "an explanation of the ranking of reasonable alternatives to the project including non-network alternatives. This ranking must be undertaken by the Transmission Network Service Providers in accordance with the principles contained in the regulatory test;

  5.6.6 re new large transmission assets: an application (b) must set out: … (1) a detailed description of: (iii) all other reasonable network and non-network alternatives to address the identified constraint or inability to meet the network performance requirements … (and see above regarding demand-side options).

As seen above, where DM or "non-network solutions" do appear, they are generally only part of a list of options which are to be, "given due and reasonable consideration". The other kind of reference is one where they are part of a requirement for options to be ranked, for instance regarding the Regulatory Test for small transmission assets.

4 Rule proposals

4.1 General problems relevant to all following Rule change proposals

In theory, under the current arrangements demand and supply should be treated equally within the NEM, but this is not the case, even in light of the proposed changes to the National Electricity Rules for distribution networks. This imbalance urgently needs to be redressed.

Transmission network service providers have a longstanding competency and business interest in operating, maintaining and augmenting highly reliable, 'poles and wires' services to meet demand. Compared to this, their familiarity, competency and interest in DM is minimal. Merely accepting this situation as a given and allowing the Rules to continue to entrench this bias is inappropriate and to the disbenefit of consumers.

The capacity of cost-effective DM in the NEM is under-utilised at the expense of the long-term interests of consumers. A recent conservative estimate of cost-effective DM capacity in the NEM states that DM potential could be around 3000MW.[16] Even this low estimate represents approximately 7.5% of NEM capacity. Yet networks routinely spend less than 1% of their capital expenditure on DM.[17]

Transmission networks consistently overlook or ignore DM when considering how to respond to demand growth and capital expenditure is driven by peak demand. As a result, consumers are being deprived of efficient network operations, lower costs and lower prices. As IPART has pointed out, the bottom 30% of network capacity is generally used 100% of the time, but the top 10% of network capacity is used for less than 1% of the time.[18] This results in highly expensive prices for the delivery of electricity at peak times. For example, according to IPART, the cost of providing distribution peak load can be around 400 times the cost of base load.[19] As IPART notes, this can have an impact on energy prices:

> *Measures targeted at peak loads (such as interruptible contracts) will principally flatten the top of the load duration curve and tend to lower peak prices, and improve asset utilization. Together, these effects are likely to lower average energy prices. Energy efficiency measures of similar magnitude that act continuously will lower peak loads and defer capital expenditure. While it may not achieve better asset utilisation, the reduced energy usage can reduce participating customers energy bills directly.*[20]

At the same time, the DM service provider market is being deprived of the opportunity to mature and compete on a level playing field with supply side solutions. The DM service provider market should be considered an integral and active participant in the NEM. At present, however, it is marginalised by the excessive focus of the National Electricity Law, the Rules and regulators on supply.

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[16] KPMG for Energy Reform Implementation Group, *Review of Energy Related Financial Markets,* November 2006, p. 101

[17] For example, "EnergyAustralia's Submission on the 2004 Distribution Determination to the Independent Pricing and Regulatory Tribunal" 10 April 2003, p. xi

[18] IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report,* October 2002, p. 5.

[19] IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report,* October 2002, p. 6.

[20] IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Final Report,* October 2002, p. 6.

4.2 General solutions relevant to all following Rule change proposals

By removing the regulatory barriers to DM, there is scope to reduce costs to consumers, while maintaining or even improving the reliability of power supplies. To ensure maximum efficiency in both investment in and use of electricity infrastructure, networks should plan for and implement DM options if found to be cost-effective. This requires a comprehensive approach across a range of regulatory areas. Critical elements include:

- Short term incentives that neutralise the current incentives for inefficient augmentation;
- Long term incentives that neutralise the current incentives for inefficient augmentation in terms of recovery of cost and sharing of efficiency benefits;
- Enhanced opportunity for DM options to be considered and adopted early on in the planning and development stage;
- Incentives for the prioritisation of DM over unnecessary network expansion to counter current:
    - 'build' focused organisational culture, expertise and conventions;
    - low awareness of and lack of familiarity with DM options;
    - the relatively undeveloped state of the DM provider industry and the associated absence of economies of scale.
- Detailed and timely reporting of emerging network constraints;
- Provision of detailed and timely public information about network capacity and emerging constraints; and
- Transparent and robust reporting of performance on DM.

Overseas experience confirms that utilising the full potential of DM would provide significant benefits to consumers. Electricity regulators in the US, for example, have pursued energy efficiency and other demand management since the early 1980s. These have entailed significant expenditures, currently at over US$1 billion annually.[21] This has generated substantial energy savings and peak load avoidance – currently estimated at approximately 60,000 gigawatt hours[22] and 25,000 megawatts[23] respectively.

DM activity in the U.S. has been successful by all metrics, including energy saved, load and peak load avoided, generation and transmission investments deferred or avoided, and emissions avoided. These activities are highly coincident with peak demand and have yielded consumer energy bill savings of about US$4 billion annually.[24]

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[21] York and Kushler, ACEEE, "State Scorecard on Utility & Public Benefits Energy Efficiency Programs: An Update" Dec 2002
[22] York and Kushler, ACEEE, "State Scorecard on Utility & Public Benefits Energy Efficiency Programs: An Update" Dec 2002
[23] U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report" as reported in U.S. EIA *Electricity Power Annual 2001*.
[24] Next Energy and Total Environment Centre, *Demand Management and the National Electricity Market,* February 2004, p. 28.

Locally, there is only sporadic interest from transmission networks in DM. One example is TransGrid's current focus on the Newcastle – Sydney – Wollongong area due to the inability of network augmentation to meet the minimum network performance requirements in time.[25] In this case, TransGrid has actively sought a demand side response (DSR) solution by issuing a request for proposals (RFP) and by engaging a consultant to facilitate the process. This has already identified at least 350MW of non-network solutions and significant further reductions including from:

> "- *all electricity distribution companies whose service territories overlap the project area*
> - *electricity retailers with a significant number of large customers in the project area*
> - *demand response aggregators*
> - *companies that build, own and operate embedded generation; and*
> - *a select number of large end-use customers."*[26]

Cost-reflective pricing, including dynamic pricing, applied to price signals sent to distribution networks can also be an effective means for transmission networks to stimulate DM. It is currently, however, a neglected means of stimulating cost-effective DM. In effect, cost-reflective dynamic pricing communicates time and locational constraints to distribution networks and would create a strong incentive for distribution networks to carry out DM.

If distribution networks were required to pay cost-reflective prices passed on by transmission networks, they would be more likely to recognise that DM is the most cost-effective solution. Cost-reflective pricing is, in effect, sending a message about congestion on to other parties. Distribution networks would not necessarily have to pass these costs onto consumers, but instead could choose to reduce demand with DM.

Considering the major bias against DM and its significant potential to deliver benefits to consumers, DM must be *actively* supported by the Rules to redress the current status quo where inefficient network capital and operating costs prevail and are passed onto consumers.

[25] NERA Economic Consulting for TransGrid, *500kV Upgrade – Preliminary Regulatory Test Analysis: A Report for TransGrid*, 18 May 2006
[26] NERA Economic Consulting for TransGrid, *500kV Upgrade – Preliminary Regulatory Test Analysis: A Report for TransGrid*, 18 May 2006, p. 27

4.3 How the following proposals meet the NEL objective: relevant to all Rule change proposals in this submission

The following explanation of how the proposed Rule changes below meet the National Electricity Market Objective apply to all proposals and are generic to the increased take-up of DM in the NEM. Further explanation at the conclusion of each Rule change proposal is specific to that proposal and should be read in conjunction with these overarching explanations.

4.3.1 Efficiency

The majority of current network augmentations are peak driven and, once built are highly inefficient. Because transmission networks fail to harness an adequate level of DM, these augmentations are usually either premature or unnecessary, creating preventable costs for consumers.

DM directly serves both efficiency aspects of the NEM objective '…*to promote efficient investment in, and efficient use of, electricity services…'*

Firstly, the use of DM solutions by networks to avoid unnecessary transmission network augmentation directly assists *efficient investment in* network and generation infrastructure. As networks account for around 40% to 50% of electricity costs and the bulk of those costs are fixed capital costs, numerous benefits follow if network augmentations, in particular, can be deferred or avoided through the use of DM. As DM can also defer or avoid expensive *generation* costs, these benefits are increased.

Secondly, the implementation of DM also directly encourages the *efficient use of* electricity by consumers. Consequently, the use of DM can lead to better cost-reflective pricing and can have a downward pressure on prices (productive efficiency), which can also have long-run effects on pricing (dynamic efficiency). Reliability benefits also have an effect on allocative efficiency.

Both of these aspects of efficiency – *investment in* and *use of* - create savings for consumers through reduced capital and operating expenditure, and reduced or altered consumption. DM has the potential to reduce both the quantity and price of electricity used.

DM can also provide *long-term* efficiency benefits. Reflecting on the long-term benefits, the NSW Department of Energy, Utilities and Sustainability has stated that,

> *It is recognised that demand reduction can provide long term network benefits, not only when the system constraint occurs. This is because such demand reduction can reduce the need for future network augmentation under a wide range of plausible future scenarios*. [27]

In practice, the DM approach to meeting demand has been found to be extremely cost-effective, even considering the small amounts of DM undertaken by networks to date. Under the NSW 'D-factor', for example, DM has been found to have an average 4.6:1 benefit to cost

[27] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice*, September 2004, p 21.

ratio.[28] In 2000-01, under the previous revenue cap regulation, NSW distribution networks achieved the following benefit to cost ratios: [29]

- Integral Energy - 9:1
- Energy Australia - 6:1
- Great Southern Energy - 6:1

This DM achieved $32million savings in one year despite the inexperience of the distribution networks and the immaturity of the DM provider market. It is likely that savings from the broad-scale take-up of DM, triggered by transmission networks across the NEM, would be many times greater than this. Sanctioning the failure to capture these efficiency benefits due to the regulatory bias towards expensive, unnecessary supply side approaches is inappropriate.

In the US, DM has achieved similar benefit to cost ratios, including:

- California – 8:1
- Connecticut – 7:1 (residential) and 2.4:1 (commercial and industrial)
- Vermont – 1.55:1
- Massachusetts –2.5:1
- Minnesota – 6:1

The cost of DM activities in the US has averaged between US$0.02-0.03 per kWh over the last two decades for a wide variety of programs. These activities are highly coincident with peak demand and have yielded consumer energy bill savings of about US$4 billion annually.[30]

Current and future greenhouse emission costs, such as those under the NSW Greenhouse Gas Abatement Scheme and the imminent costs under a national emissions trading scheme will increase the cost-effectiveness of DM in the NEM. This is due to the likelihood that DM will increasingly be more competitive than greenhouse intensive supply side options. To inhibit the take-up of DM within the NEM, particularly in the context of rising electricity prices as a result of climate change responses, is inappropriate.

4.3.2 Reliability

DM directly serves the long-term interests of consumers in respect to both '*reliability of supply'* and the '*reliability of the national electricity system'.*

DM improves both of these aspects of reliability through its capacity to ease specific constraints at times of peak demand, as well as its ability to reduce overall load on the system, reducing the risk of system failures.

"Reliability" is defined in the Rules Glossary as: "The probability of a system, device, plant or equipment performing its function adequately for the period of time intended, under the

[28] Institute for Sustainable Futures for Total Environment Centre, *Win, Win, Win: Regulating Distribution Networks for Reliability, Consumers and the Environment – A Review of the NSW D-Factor and Alternative Mechanisms to Encourage Demand Management*, Draft Report, November 2007.
[29] Ministry of Energy and Utilities, *Electricity Network Performance Report,* 2000-01, p.2.
[30] Next Energy and Total Environment Centre, *Demand Management and the National Electricity Market,* February 2004, p. 28.

operating conditions encountered." Direct load control and DM aggregation, in particular, can reduce network risks by targeting peak demand DM at times of high demand, such as unpredictably hot summer days, or when an unplanned outage occurs in combination with peak demand. As such, it provides excellent insurance against system failures.

DM is a far more flexible and timely way of addressing spikes in peak demand than augmentation. As such it can harness huge amounts of DM in a short space of time and thus should be a key aspect of reliable energy system. Evidence of the timely availability of a demand side response (DSR) is shown by the Energy Users Association of Australia paper trial which captured 119.4MW of short-notice demand response with only 93 participants.[31] It should be noted that this trial did not cover the full range of DM aggregation. With market Rules that facilitate DM bidding, regulatory support and real life implementation, it is expected that the full demand side response potential would be many times greater than this and could be facilitated by smart meters to include the residential and small business sectors. As Energy Response has noted:

> *As a contribution to meeting reliability standards, [DSR is] the best possible action to take when there is a shortage of either supply or transmission capacity. This is exactly what a well organised source of DSR can do far more efficiently and effectively than more supply side capacity or additional transmission lines.*[32]

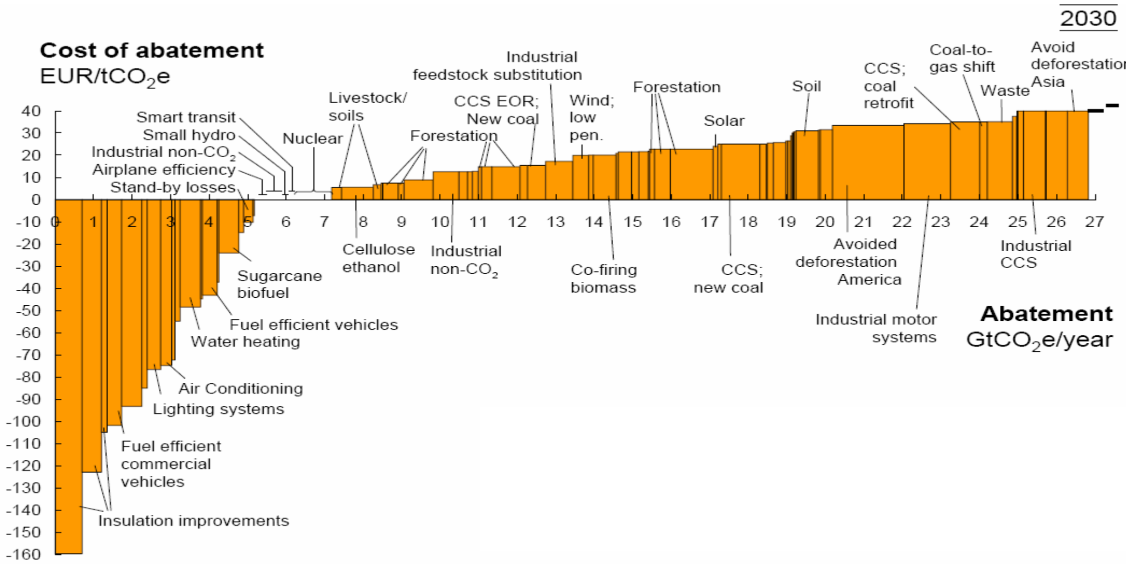
4.3.3 Greenhouse emissions, carbon costs and broader economic impacts

DM also serves the long-term interests of consumers by reducing greenhouse emissions arising from electricity consumption. Greenhouse emissions cause significant long-term negative impact on consumers, in terms of:

- carbon costs which are passed on in electricity prices (both current and future);
- carbon costs which impact on the broader economy (for example, water and food prices); and,
- the externalised costs of environmental degradation.

The following table shows the relative costs of greenhouse emissions abatement to 2030.[33] It reveals that nearly a quarter of all abatement potential involves DM measures, in particular, energy efficiency. These carry *no net cost* compared to supply alternatives such as carbon capture and storage or a shift from coal to gas-fired power. Clearly, the opportunity cost to consumers of ignoring DM potential is immense.

[31] Energy Users Association of Australia, *Press Release: New report confirms economic benefits to end users of demand side response (DSR) in the electricity market*, 21 October 2005.
[32] Energy Response, *AEMC Reliability Panel Comprehensive Reliability Review, Response to Interim Report March 2007*, 17 May 2007, p. 3.
[33] The McKinsey Quarterly, 'A cost curve for greenhouse gas reduction', 2007 Number 1, p. 38.



Despite the current regulatory disconnect between the long-term interests of consumers as seen in a narrow economic sense and the broader long-term interests of consumers, DM’s contribution to reducing future carbon costs, avoiding wide-scale economic devastation and facilitating protection of the environment is integral to meeting community needs.

4.4 Transmission network planning

4.4.1 The problem

An overall bias towards network augmentation over a DM response to constraints is found throughout the Rules, particularly in Chapter 5. This bias is both general, in the language used to describe network processes, and specific, in the Rules that guide the networks' planning processes without attempting to correct the bias towards inefficient augmentation.

This problem is partly caused by the failure of regulation to address the inappropriate incentives created by the situation where networks are both the monopoly planner and procurer of networks services. When it comes to DM under current regulations, networks are expected to facilitate competition between themselves as owner and builder of network infrastructure and providers of DM services.[34] There is a clear conflict of interest in this arrangement, which is not corrected by regulators and is worsened by the strong incentives that networks have to expand their networks and thus generate more revenue. This has created a situation where transmission networks strongly favour investment in their own networks at the expense of DM.

In practice, the network augmentation approach is the priority focus and DM solutions are either not considered or are considered without appropriate or transparent analysis. An cursory inspection of the transmission networks' Annual Planning Reports, where they exist, shows that DM is either not considered or given cursory mention. As NSW's Independent Pricing and Regulatory Tribunal has noted:

> *To a large extent, one of the major obstacles continues to be a culture which favours traditional 'build' engineering solutions and which pays little more than lip service to alternative options.*[35]

4.4.2 The solution

It is critical that regulators, rather than accept the inefficient 'build culture' of transmission network planning as a given, recognise that the regulatory framework is actively perpetuating inefficient behaviour and takes action to transform those behaviours by changing the Rules.

Section 5.6 of the Rules focuses on network planning and development. As such it is a key area where the failure of networks to utilise DM should be addressed.

The changes below are designed to ensure that networks thoroughly consider DM solutions before network augmentation alternatives and, therefore, that DM is implemented when it more cost-effective than augmentation. The changes are also designed to take the bias towards augmentation out of the language of the Rules.

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[34] As noted in, Institute for Sustainable Futures, *Win, Win, Win: Regulating Distribution Networks for Reliability, Consumers and the Environment – A Review of the NSW D-Factor and Alternative Mechanisms to Encourage Demand Management*, Draft Report, forthcoming.
[35] IPART Foreword, Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Oct 2002.

4.4.3 Proposed Rule changes

Change 5.6.2 (c) to:

(c) Where the necessity to respond to the likely exceedence of the transmission network's technical limits ~~for *augmentation* or a non-network alternative~~ is identified by the annual planning review conducted under clause 5.6.2(b), the relevant *Network Service Providers* must undertake joint planning in order to determine plans that can be considered by relevant *Registered Participants*, *NEMMCO* and *interested parties.*

Change current 5.6.2 (e) to:

(e) Each *Network Service Provider* must extrapolate the forecasts provided to it by *Registered Participants* for the purpose of planning and, where this analysis indicates that any relevant technical limits of the *transmission or distribution systems* will be exceeded, either in normal conditions or following the contingencies specified in schedule 5.1, the *Network Service Provider* must notify any affected *Registered Participants* and *NEMMCO* of these limitations and advise those *Registered Participants* and *NEMMCO* of the expected time required to allow the appropriate corrective *demand side* solutions or network *augmentation* alternatives ~~network *augmentation* or non-*network* alternatives~~, or modifications to *connection facilities* to be undertaken.

Insert after 5.6.2 (e)

(x) Within the time for corrective action notified in clause 5.6.2(e) the relevant *Transmission Network Service Provider* must consult with affected *Registered Participants*, *NEMMCO* and *interested parties* on the possible *demand side* options to address the projected limitations of the relevant *transmission system.*

(x) Each *Transmission Network Service Provider* must carry out an economic cost effectiveness analysis of possible *demand side* options to identify *demand side* options that satisfy the *regulatory test*, while meeting the technical requirements of schedule 5.1, and where the *Network Service Provider* is required by clause […] to consult on the option this analysis and allocation must form part of the consultation on that option.

(x) Following conclusion of the process outlined in clauses 5.6.2(f) and (g), the *Transmission Network Service Provider* must prepare a report that is to be made available to affected *Registered Participants*, *NEMMCO* and *interested parties* which includes assessment of all identified *demand side* options and their economic cost-effectiveness.

(x) The *Transmission Network Service Provider* must recommend its preferred demand side option which includes details of the *Transmission Network Service Provider's* preferred demand side proposal and details of:

> (A) its economic cost effectiveness analysis in accordance with clause 5.6.2(g); and
> (B) its consultations conducted for the purposes of clause 5.6.2(g);
>
> > (3) summarises the submissions from the consultations; and
> > (4) recommends the demand side action to be taken.

Change current 5.6.2 (f) to:

(f) Within the time for corrective action notified in clause 5.6.2(e) the relevant *Distribution Network Service Provider* must consult with affected *Registered Participants*, *NEMMCO* and *interested parties* on the possible *demand side* options~~, including but not limited to demand side options, *generation* options and *market network service* options~~ to address the projected limitations of the relevant *distribution system* except that a *Distribution Network Service Provider* does not need to consult on a *network* option which would be a *new small distribution network asset*.

Change current 5.6.2 (g) to:

(g) Each *Distribution Network Service Provider* must carry out an economic cost effectiveness analysis of possible *demand side* options to identify *demand side* options that satisfy the *regulatory test*, while meeting the technical requirements of schedule 5.1, and where the *Network Service Provider* is required by clause ~~5.6.2(f)~~[…] to consult on the option this analysis and allocation must form part of the consultation on that option.

Change current 5.6.2 (h) to:

(x) Following conclusion of the process outlined in clauses 5.6.2(f) and (g), the *Distribution Network Service Provider* must prepare a report that is to be made available to affected *Registered Participants*, *NEMMCO* and *interested parties* which includes assessment of all identified *demand side* options and their economic cost-effectiveness.

Insert after current 5.6.2 (h):

(i) The Distribution Network Service Provider must recommend its preferred demand side option which includes details of the *Distribution Network Service Provider's* preferred demand side proposal and details of:

(A) its economic cost effectiveness analysis in accordance with clause […]; and

(B) its consultations conducted for the purposes of clause 5.6.2(g);

(3) summarises the submissions from the consultations; and

(4) recommends the demand side action to be taken.

[Note: For transmission and distribution networks, the above processes should each be followed by a comparative assessment of augmentation alternatives. Then a further comparative step should be undertaken to compare DM solutions to augmentation alternatives]:

(h) Following conclusion of the processes outlined in clauses […] and […], the *Network Service Provider* must prepare a report that is to be made available to affected *Registered Participants*, *NEMMCO* and *interested parties* which:

(1) includes assessment of all identified options;

(2) includes details of the *Distribution Network Service Provider's* preferred proposal and details of:

(A) its economic cost effectiveness analysis in accordance with clause 5.6.2(g); and

(B) its consultations conducted for the purposes of clause 5.6.2(g);

(3) summarises the submissions from the consultations; and

(4) recommends the action to be taken.

[Note: We recognise that these changes affect the augmentation steps including and following existing Rule 5.6.2 (i). The AEMC will need to amend Rules 5.6.2 (i) and those following to reflect two possible planning pathways. Firstly, the Rules should assume that a demand side option is proposed and then recommended. Secondly, should all cost-effective DM solutions be exhausted, the Rules would need to outline the ‘fall-back’ process for the assessment and implementation of augmentation alternatives.]

4.4.4 How this proposal meets the NEM Objective

DM is currently under-utilised, resulting in inefficient investment in and use of electricity in the NEM. By guaranteeing that DM is properly considered, in a timely manner and at the initial planning stage, this Rule change will assist with the increased delivery of level of DM.

Implementing a more adequate level of DM will increase the efficient *investment in* and *efficient use of* electricity services in the long-term interests of consumers.

4.5 Annual Planning Reports

4.5.1 The problem

Transmission networks consistently overlook or ignore DM when considering how to respond to demand growth. This is part of a long-standing cultural bias against DM within networks. The failure to properly investigate DM is resulting in a lack of information being made available to possible DM suppliers, which hinders the DM service provider market from competing with augmentation alternatives to address network constraints. The perverse outcome of the failure of transmission networks to provide proper and timely information on upcoming constraints is that on the rare occasion that they consider DM as an option, there is little or no response from the DM provider market.

This is one of the many barriers contributing to the failure of the emergence of a robust DM provider market and hence the more efficient investment in and use of electricity. The lack of detailed data results in an information asymmetry which undermines DM opportunities. It reflects the conflict of interest that networks have when they compete with external providers of network support services.

A related problem is the lack of *ex post* reporting on DM. There is a lack of transparency in reporting on DM efforts including:

- efforts to identify and procure cost-effective DM;
- expenditure on DM;
- peak demand and energy consumption reductions;
- the value of electricity sales foregone;
- the value of capital and operating expenditure avoided or deferred.

This makes it impossible for regulators and consumers to assess the degree to which networks are utilising an adequate level of DM.[36]

4.5.2 The solution

Transmission networks should be required to publish robust data on upcoming constraints that are relevant and useful to DM service providers. This would serve to inform the DM market of upcoming opportunities and enable it to respond to these in a timely manner. The NSW DM Code of Practice for Distributors and the South Australian Guideline 12 provide sound precedents for such information disclosure by distributors.

NSW has recognised the benefit of robust information provision in relation to distribution networks through the Demand Management Code of Practice for Electricity Distributors. As the Code of Practice notes:

[36] An example of this problem can be seen in TransGrid's *Annual Planning Report 2007* where network augmentations are discussed in detail while DM solutions are routinely dismissed with minimal evaluation.

> *…to ensure competitive neutrality, third party proponents should have comparable access to the information required to develop alternative proposals. Third parties should also be able to have confidence that their proposals will be given due consideration in the evaluation of proposals.*[37]

Regulators and consumers must be able to ascertain if networks are utilising an adequate level of DM in order to determine whether or not networks are operating efficiently. The Rules should require that Annual Planning Reports include:

- detailed information about the current and future capacity of the transmission network; and

- current projected demand and possible options to address any emerging constraints.

The Rules should also require both distribution and transmission networks to report annually on DM activities undertaken in relation to:

- expenditure;
- peak demand and energy consumption reductions;
- value of electricity sales foregone;
- value of capital and operating expenditure avoided or deferred; and
- efforts to identify and procure cost effective DM.

To assist with this, the Rules should require the AER to issue a pro forma to ensure consistency in DM reporting. Such reports should be publicly available.

4.5.3 Proposed Rule changes

Change 5.6.2A (b) (3) to:

(3) a forecast of *constraints* for each asset over XXMVA and each connection point and inability to meet the *network* performance requirements set out in schedule 5.1 or relevant legislation or regulations of a *participating jurisdiction* over 1, 3 ~~and~~, 5 *and 10* years, including;

a. total capacity, firm delivery capacity and peak load (as in D4. above);
b. extent of overload (peak load > firm capacity; MVA);
c. frequency of overloads (days pa where peak load > firm capacity);
d. length of overloads (hours pa where peak load > firm capacity);
e. power factor at time of peak load;
f. load trace/data for (current actual) peak day;
g. annual load duration curve/data;
h. distribution networks connected to constrained asset;
i. a statement of whether transmission network plans to issue a Request for Proposals (RFP) for electricity system support and if so, the expected date that the RFP will be issued;

[37] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice*, September 2004, p 8.

j. an outline of how the transmission network intends to inform and test the market, including but not limited to:

(i) *requests for proposals;*
(ii) direct consultation with major customers;
(iii) pilot demand management initiatives;
(iv) standard or negotiated offerings ;
(v) use of energy service companies, demand management aggregators and market intermediaries;
(vi) arrangements with distribution networks;

Change current 5.6.2A (b) (4) to:

(4) for all proposed ~~*augmentations*~~ *demand side solutions* to the *network* the following information, in sufficient detail shall be provided to clearly describe~~relative to the size or significance of the project and the proposed operational date of the project~~:

(i) project~~/asset~~ name and the month and year in which it is proposed that the ~~asset~~ project will become operational;
(ii) the reason for the actual or potential *constraint*, if any, or inability, if any, to meet the *network* performance requirements set out in schedule 5.1 or relevant legislation or regulations of a *participating jurisdiction*, including *load* forecasts and all assumptions used;
(iii) the proposed demand side solution to the *constraint* or inability to meet the *network* performance requirements identified in clause 5.6.2A(b)(4)(ii), if any;
(iv) total cost of the proposed demand side solution including;
(i) implementation costs of the demand side solution;
(ii) annualised operating costs;
(ii) costs of sales foregone as a result of the demand side solution;
(v) whether the proposed demand side solution will have a *material inter-network impact*. In assessing whether a demand side solution to the *network* will have a *material inter-network impact* a *Transmission Network Service Provider* must have regard to the objective set of criteria *published* by the *Inter-regional Planning Committee* in accordance with clause 5.6.3(i) (if any such criteria have been *published* by the *Inter-regional Planning Committee*); and
(vi) other ~~reasonable~~ *demand side* options considered to address the actual or potential *constraint* or inability to meet the *network* performance requirements identified in clause 5.6.2A(b)(4)(ii), if any. Other ~~reasonable~~ *demand side* options include, but are not limited to, *demand side* aggregation services, stand-by power, distributed generation options, cogeneration, power factor correction, fuel switching, interruptible customer contracts, and other load shifting mechanisms, which can involve other *transmission* and *distribution networks*. *Network options include interconnectors*, *generation* options, *market network service* options and options involving other *transmission* and *distribution networks*;

Insert after 5.6.2A (b) (4):

(X) Once all *demand side* options have been exhausted, for all proposed *augmentations* to the *network* the following information, in sufficient detail relative to the size or significance of the project and the proposed operational date of the project:

(i) project/asset name and the month and year in which it is proposed that the asset will become operational;

(ii) the reason for the actual or potential *constraint*, if any, or inability, if any, to meet the *network* performance requirements set out in schedule 5.1 or relevant legislation or regulations of a *participating jurisdiction*, including *load* forecasts and all assumptions used;

(iii) the proposed solution to the *constraint* or inability to meet the *network* performance requirements identified in clause 5.6.2A(b)(4)(ii), if any;

(iv) total cost of the proposed solution;

(v) whether the proposed solution will have a *material inter-network impact*. In assessing whether an *augmentation* to the *network* will have a *material inter-network impact* a *Transmission Network Service Provider* must have regard to the objective set of criteria *published* by the *Inter-regional Planning Committee* in accordance with clause 5.6.3(i) (if any such criteria have been *published* by the *Inter-regional Planning Committee*); and

(vi) other *network* and non-*network* options considered to address the actual or potential *constraint* or inability to meet the *network* performance requirements identified in clause 5.6.2A(b)(4)(ii), if any. Other reasonable *network* and non-*network* options include, but are not limited to, *interconnectors*, *generation* options, demand side options, *market network service* options and options involving other *transmission* and *distribution networks*;

Change 5.6.2A (b) (5) to:

(5) for all proposed ~~*new small transmission network assets*~~*demand side solutions*:

(i) an explanation of the ranking of ~~reasonable~~ *demand side* alternatives to the project ~~including non-*network* alternatives~~. This ranking must be undertaken by the *Transmission Network Service Provider* in accordance with the principles contained in the *regulatory test*;

(ii) a *demand side* technical ~~an *augmentation technical*~~ *report* prepared by the *Inter-regional Planning Committee* in accordance with clause 5.6.3(j) if, and only if, the asset is reasonably likely to have a *material inter-network impact* and the *Transmission Network Service Provider* has not received the consent to proceed with the proposed solution from all *Transmission Network Service* Providers whose *transmission networks* are materially affected by the *new small transmission network asset*. In assessing whether a *new small transmission network asset* is reasonably likely to have a *material inter-network impact*, a *Transmission Network Service Provider* must have regard to the objective set of criteria *published* by the *Inter-regional Planning Committee* in accordance with clause 5.6.3(i) (if any such criteria have been *published* by the *Inter-regional Planning Committee*); and

(iii) analysis of why the *Transmission Network Service Provider* considers that the ~~*new small transmission network asset*~~ *demand side* solution satisfies the *regulatory test* and, where the *Transmission Network Service Provider* considers that the *new small* ~~*transmission network asset*~~ *demand side* solution satisfies the *regulatory test* as the ~~*new small transmission network asset*~~ *demand side* solution is a *reliability augmentation*, analysis of why the *Transmission Network Service Provider* considers that the ~~*new small*~~ *demand side* solution~~transmission~~ ~~*network asset*~~ is a *reliability* ~~*augmentation*~~*solution*. In assessing whether a ~~*new small*~~ *demand side* solution ~~*transmission network asset*~~ is a *reliability* ~~*augmentation*~~*solution*, a *Transmission Network Service Provider* must consider whether the ~~*new small*~~*demand side* solution ~~*transmission network asset*~~ satisfies the criteria for a *reliability* ~~*augmentation*~~ *demand side* solution *published* by the *Inter-regional Planning Committee* in accordance with clause 5.6.3(l) (if any such criteria have been *published* by the *Inter-regional Planning Committee*).

Insert after new 5.6.2A (b) (5):

(6) once all *demand side options* have been exhausted, for all proposed *new small transmission network assets*:

(i) an explanation of the ranking of augmentation alternatives to the project including non-*network* alternatives. This ranking must be undertaken by the *Transmission Network Service Provider* in accordance with the principles contained in the *regulatory test*;

(ii) an *augmentation technical report* prepared by the *Inter-regional Planning Committee* in accordance with clause 5.6.3(j) if, and only if, the asset is reasonably likely to have a *material inter-network impact* and the *Transmission Network Service Provider* has not received the consent to proceed with the proposed solution from all *Transmission Network Service* Providers whose *transmission networks* are materially affected by the *new small transmission network asset*. In assessing whether a *new small transmission network asset* is reasonably likely to have a *material inter-network impact*, a *Transmission Network Service Provider* must have regard to the objective set of criteria *published* by the *Inter-regional Planning Committee* in accordance with clause 5.6.3(i) (if any such criteria have been *published* by the *Inter-regional Planning Committee*); and

(iii) analysis of why the *Transmission Network Service Provider* considers that the *new small transmission network asset* satisfies the *regulatory test* and, where the *Transmission Network Service Provider* considers that the *new small transmission network asset* satisfies the *regulatory test* as the *new small transmission network asset* is a *reliability augmentation*, analysis of why the *Transmission Network Service Provider* considers that the *new small transmission network asset* is a *reliability augmentation*. In assessing whether a *new small transmission network asset* is a *reliability augmentation*, a *Transmission Network Service Provider* must consider whether the *new small transmission network asset* satisfies the criteria for a *reliability augmentation published* by the *Inter-regional Planning Committee* in accordance with clause 5.6.3(l) (if any such criteria have been *published* by the *Inter-regional Planning Committee*).

Insert after new 5.6.2A (b) (6):

(7) detailed information that complies with the *prescribed demand side reporting format* on all *demand side activities* undertaken during the previous year including:

(i) expenditure on *demand side activities*
(ii) peak demand and energy consumption reductions achieved by *demand side activities*
(iii) value of electricity sales foregone by *demand side activities*
(iv) value of capital and operating expenditure avoided or deferred *demand side activities*
(v) efforts to identify and procure cost-effective *demand side* solutions.

[Note: the AEMC or AER would need to develop and prescribe the methodology for a demand side reliability solution, and the methodology for demand side reporting and criteria, and include this within the Rules.]

4.5.4 How this proposal meets the NEM Objective

Without thorough reporting requirements that require the proper and fair investigation of DM, and without proper reporting on the outcomes of those investigations, it is unlikely that transmission networks will improve their performance on DM. These Rule change proposals will help to ensure that transmission networks properly investigate and report on DM, and therefore more properly improve their efficiency through the increased uptake of DM.

Improved reporting on DM outcomes will better allow regulators to ascertain whether or not an adequate level of DM has been achieved by transmission networks. With this information, regulators, policy makers, consumers and other stakeholders can more properly ascertain the actual level of DM uptake and whether this is an adequate level or not. In this way, regulators, policy makers, consumers and other stakeholders can determine whether further Rule changes are necessary to improve DM uptake and achieve more efficient network operations.

4.6 DM Incentive

4.6.1 The problem

Transmission networks consistently overlook or ignore DM when considering how to respond to demand growth. This is partly caused by the failure of the Rules to provide adequate incentives for transmission network DM. Transmission networks currently have massive financial incentive for augmenting their asset bases. This incentive stems directly from their ability to earn a return on those capital investments. For DM, however, there is no such incentive.

While in theory, under a revenue cap, it is possible for a network to create savings from undertaking DM instead of a planned augmentation, the incentive for this activity is minimal compared to the ability to simply plan for and execute an augmentation option. In essence, 'business as usual', that is, network building, is the simplest and easiest option for networks. However, it is not the most efficient option for network efficiency or consumers.

4.6.2 The solution

In recognition of the failure of networks to invest in cost-effective DM, there should be an explicit provision for the AER to develop and implement a demand side incentive scheme.

4.6.3 Rule change proposal

Insert after 6A.7.4:

(a) The *AER* must, in accordance with the *transmission consultation procedures*, develop and *publish* an incentive scheme ('a *demand side incentive scheme'*) that complies with the principles in paragraph (b).

(b) The principles are that the *demand side incentive scheme* should:

(1) provide incentives for each *Transmission Network Service Provider* to:

(i) reduce demand on the *transmission system* that is owned, controlled or operated by it at all times when the *transmission system* is forecast to be constrained within 10 years; and

(ii) reduce peak demand on the *transmission system* that is owned, controlled or operated by it at all times when the *transmission system* is expected to experience critical peak demand;

(2) result in a potential adjustment to the revenue that the *Transmission Network Service Provider* may earn, from the provision of *prescribed transmission services*, in each *regulatory year* in respect of which the *demand side incentive scheme* applies;

(3) take into account the *regulatory obligations* with which *Transmission Network Service Providers* must comply;

(4) take into account any other incentives provided for in the *Rules* that *Transmission Network Service Providers* have to minimise capital or operating expenditure

(c) At the same time as it *publishes* a *demand side incentive scheme*, the *AER* must also *publish* parameters (the *demand side incentive scheme parameters*) for the scheme. For the avoidance of doubt, the parameters may differ as between *Transmission Network Service Providers* and over time.

(d) The *AER* must set out in each *demand side incentive scheme* any requirements with which the values attributed to the *demand side incentive scheme* must comply, and those requirements must be consistent with the principles set out in paragraph (b).

(e) The *AER* must develop and *publish* the first *demand side incentive scheme* under the *Rules* by 1 July 2008 and there must be a *demand side incentive scheme* in force at all times after that date.

(f) The *AER* may, from time to time and in accordance with the *transmission consultation procedures*, amend or replace any scheme that is developed and *published* under this clause, except that no such amendment or replacement may change the application of the scheme to a *Transmission Network Service Provider* in respect of a *regulatory control period* that has commenced before, or that will commence within 15 months of, the amendment or replacement coming into operation.

(g) Subject to paragraph (h) the *AER* may, from time to time and in accordance with the *transmission consultation procedures*, amend or replace the values to be attributed to the *demand side incentive scheme.*

(h) An amendment or replacement referred to in paragraph (g) must not change the values to be attributed to the *demand side incentive scheme* where:

(1) those values must be included in information accompanying a *Revenue Proposal;* and

(2) the *Revenue Proposal* is required to be submitted under clause 6A.10.1(a) at a time that is within 2 months of the *publication* of the amended or replaced *demand side incentive scheme.*

4.6.5 How this proposal meets the NEM Objective

Without an incentive mechanism for DM, it is almost certain that transmission networks will continue to operate in an inefficient manner to the disbenefit of consumers. An incentive scheme that ensures that an adequate level of DM is undertaken by transmission networks will enhance the long-term interests of consumers by promoting the use of an adequate level of DM to avoid premature or unnecessary network augmentations.

4.7 Financial cover for DM investments

4.7.1 The problem

The absence of an incentive mechanism for demand side activities (discussed in 4.4 above) is exacerbated by the lack of certainty regarding the ability of transmission networks to recover DM expenditure. This lack of certainty is exacerbated by transmission networks' propensity to not properly investigate and implement DM. While there is extensive detail on the recovery of expenditure on the transmission networks' regulated asset base, there is scant detail on how a transmission network is to recover either operating or capital expenditure on demand side activities.

TransGrid has argued that uncertainty in the treatment of DM by the ACCC may have deterred it from selecting non-network options:

> *Any uncertainty as to the regulatory treatment of DSM-related expenditure by TNSPs has the potential to undermine the practical consideration of such alternatives.*[38]

4.7.2 The solution

The circumstances in which transmission networks can recover expenditure on demand side activities needs to be clearly specified. Transmission networks must be able to include a return of and return on DM expenditure, including recognition of the opex/capex trade-off that DM activities often entail and the implications of this for network revenue.

4.7.3 Proposed Rule changes

Insert after 6A.2.2

(5) a determination that specifies the circumstances under which a Transmission Network Service Providers is able to recover operating and capital expenditure on *demand side* activities

Insert after 6A.4.2 (4)

(X) the values that are to be attributed to the *demand side incentive scheme parameters* for the purposes of the application to the provider of any *demand side incentive scheme* that applies in respect of the *regulatory control period*;

Insert after 6A.5.3 (b) (5)

(X) the *demand side incentive* methodology that is to be applied as part of the *maximum allowed revenue* for the provider for each *regulatory year* (other than the first *regulatory year*) of a *regulatory control period*.

[38] NERA for TransGrid, *Augmentation of Supply to the Western Area: Preliminary Cost Effectiveness Analysis*, May 2003, p 36

Insert after 6A.5.4 (a)(5)

(X) certain revenue increments or decrements for that year arising from *demand side incentive scheme*

[Note: There are clearly other Rule changes that would flow from the above proposals, in particular, the details of implementing a demand side incentive scheme and how it interacts with transmission network revenue. The above proposals provide a foundation, and further work on the development of a demand side incentive scheme and its revenue implications should be undertaken by the AEMC.]

4.7.4 How this proposal meets the NEM Objective

Clarity for networks on the circumstances in which they can recover DM expenditure would encourage more DM and as a result increase network efficiency.

4.8 Revenue determinations

4.8.1 The problem

As noted above, transmission networks consistently overlook or ignore DM when considering how to respond to demand growth. This is due to a regulatory approach that sanctions a bias towards supply side options and is embedded in the current revenue determination process. Supply side approaches are prioritised in the revenue determination process, which gives them the advantage of incumbency as the preferred option. Once these supply side solutions are investigated, it is highly unlikely that a demand side activity will be successful. As Energy Response has noted:

> *The regulatory process for determining network revenues provides little practical incentive for network service providers to pursue non-traditional solutions such as highly targeted DSR.*[39]

4.8.2 The solution

It is necessary to prioritise DM activities to ensure they are prioritised, properly investigated and integrated into revenue determinations.

4.8.3 Proposed Rule changes

Insert after 6A.6.6 (a)

(X) reduce expected demand for *prescribed transmission services* over that period;

Insert after 6A.6.6 (e) (8)

(X) whether the total labour costs included in the capital and operating expenditure forecasts for the *regulatory control period* are consistent with the incentives provided by the applicable *demand side incentive scheme* in respect of the *regulatory control period*;

Insert after 6A.6.7 (a)

(X) reduce expected demand for *prescribed transmission services* over that period;

Insert after 6A.6.7 (b) (4):

(X) identify any forecast capital or operating expenditure:
    (x) that is for demand side activities

Insert after S6A.1.1 (3)

(x) a description of all demand side activities taken to reduce load growth including:
    (i) cost-reflective pricing, including dynamic peak pricing

[39] Energy Response, *Response to the AEMC Reliability Panel Comprehensive Reliability Review*, 30 June 2006, p. 4

(ii) expenditure
(iii) peak demand and energy consumption reductions
(iv) value of electricity sales foregone
(v) value of capital expenditure avoided or deferred
(vi) efforts to identify and procure cost-effective demand side solutions.

Insert after S6A.1.2 (1)

(x) all demand side activities

Insert after S6A.1.2 (1) (iii)

(x) the categories of *demand side activities* to which that forecast expenditure relates;

Change S6A.1.2 (1) (iii) (3) to:

(3) the forecasts of key variables relied upon to derive the operating expenditure forecast and the methodology used for developing those forecasts of key variables, including forecasts of;

(i) cost-reflective pricing, including dynamic peak pricing
(ii) expenditure on demand side activities;
(iii) peak demand and energy consumption reductions;
(iv) value of electricity sales foregone; and
(v) value of capital expenditure avoided or deferred;

Change 6A.14.1 to:

A draft decision under rule 6A.12 or a final decision under rule 6A.13 is a decision by the *AER*:
(1) on the *Transmission Network Service Provider's* current *Revenue Proposal* in which the *AER* either approves or refuses to approve:
(i) the *total revenue cap* for the provider for the *regulatory control period*;
(ii) the *maximum allowed revenue* for the provider for each *regulatory year* of the *regulatory control period*;
(iii) the values that are to be attributed to the *performance incentive scheme parameters* for the *service target performance incentive scheme* that is to apply to the provider in respect of the *regulatory control period*;
(iv) the values that are to be attributed to the *efficiency benefit sharing scheme parameters* for the *efficiency benefit sharing scheme* that is to apply to the provider in respect of the *regulatory control period*; ~~and~~
(v) the values that are to be attributed to the *demand side incentive scheme parameters* for the *demand side incentive scheme* that is to apply to the provider in respect of the *regulatory control period; and*
(vi) the commencement and length of the *regulatory control period* that has been proposed by the provider, as set out in the *Revenue Proposal*, setting out the reasons for the decision;

4.8.4 How this proposal meets the NEM Objective

This proposal strengthens the investigation and integration of DM in revenue determinations. By ensuring that transmission networks focus on DM and account for DM programs in their revenue proposals, it is more likely that DM options will be integrated more thoroughly and therefore succeed.

Greater uptake of DM, to an adequate level as determined by the regulator, is in the long-term interests of consumers because it encourages more efficient investment in network operations and more efficient use of electricity by consumers.

4.9 Acknowledgment of modest DM expenditure

4.9.1 The problem

A major barrier to the implementation of DM by networks concerns the inability of networks to recover expenditure on modest DM investments. Such expenditure may not directly contribute to the alleviation of a particular constraint at a particular time, but it is likely that accumulating savings will. It is therefore illogical that modest DM activities be excluded from revenue determinations simply because they are not linked to a specific constraint.

As the NSW Department of Energy, Utilities and Sustainability has noted;

> *It is recognised that demand reduction can provide long term network benefits, not only when the system constraint occurs. This is because such demand reduction can reduce the need for future network augmentation under a wide range of plausible future scenarios.*[40]

4.9.2 The solution

There needs to be explicit acknowledgement of the potential use and value of small scale demand side activities in covering relatively modest amounts of load or hours at risk. This is to ensure that investment in demand side solutions is considered and can be recovered even in small applications.

4.9.3 Proposed Rule changes

Insert after 5.6.5A (c) (8):

(9) ensure that *demand side activities* that are able to achieve less than a single full year's deferral of network investment are assessed and evaluated in proportion to the share of the full year's deferral that they can deliver and/or in relation to the reduction in risk of unserved demand.

4.9.4 How this proposal meets the NEM Objective

Efficient network operations are in the long-term interests of consumers, even when the evaluation of the cost-effectiveness of DM is not able to be compared with a present constraint. It is likely that, particularly without cost-effective DM, the entire grid will be constrained at some time in the future. Modest DM is therefore in the interests of consumers as it increases overall transmission network efficiency.

[40] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice*, September 2004, p 21.

4.10 Effective prudency reviews

4.10.1 The problem

Transmission networks consistently overlook or ignore DM when considering how to respond to demand growth. Despite the fact that this is the norm, there have been only few instances where this has been explicitly acknowledged by the regulatory bodies. One such case was the failure of TransGrid to consider and/or implement viable, cost-effective DM solutions in the Sydney CBD despite the savings on offer.[41] In this case, consumers lost savings of over $140million relative to the network augmentation adopted by TransGrid and EA.[42] In its final determination, the ACCC disallowed TransGrid $31million in 2003/4 dollars for this failure.[43]

The TransGrid CBD augmentation problem is merely one example of the overwhelming majority of transmission augmentations across the NEM that fail to properly investigate or undertake cost-effective DM solutions. Almost all failures to harness efficiency through DM are overlooked by regulators, at the expense of the long-term interests of consumers.

4.10.2 The solution

Prudency reviews that assess past and projected capital expenditure should be undertaken, conducted by experts with a demonstrated balanced understanding of the theory and practice of DM. These should specifically and thoroughly assess the extent to which transmission networks have implemented, and not ignored, an adequate level of DM. An objective approach to monitoring, along with a requirement for explicit demonstration that DM solutions have been thoroughly considered, is essential. Anything short of a stringent approach to the assessment of DM take-up is implicit acceptance of inefficient network expenditure at the expense of consumers.

Transmission networks need to document whether and the extent to which they have proactively pursued DM solutions. This could take the form of monitoring the rate at which the various transmission networks are implementing cost-reflective pricing, including dynamic pricing, issuing requests for proposals (RFPs) or standard offers for DM solutions. The rate of implementation of DM solutions also needs to be monitored.

Revenue should be disallowed for expenditure that ignores cost-effective DM. This would provide a useful incentive for transmission networks to avoid inefficient network augmentation.

Annual Planning Reports, written in accordance with the Rule changes contained in this proposal, should assist in providing the information necessary for the AER to assess whether an adequate level of DM has been implemented.

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[41] For example, Mountain Associates for ACCC, *An assessment of the prudency of TransGrid's investment in the MetroGrid project*, April 2004.

[42] Next Energy and Total Environment Centre, *Demand Management and the National Electricity Market,* February 2004, p. 19.

[43] ACCC, *NSW and ACT Transmission Network Revenue Cap TransGrid 2004/5 to 2008/9: Final Decision,* 27 April 2005, p. 88

4.10.3 Proposed Rule changes

Insert after S6A.2.2 (6)

(X) whether the provider undertook or procured an efficient level of *demand side activities* so as to avoid undertaking inefficient capital expenditure and to achieve the lowest sustainable cost of delivering the *prescribed transmission services*. To achieve this, the AER must develop a methodology to determine the efficient level of *demand side activities*, having regard to:

> (i) the implementation cost of the *demand side activity;*
> (ii) the annualised value of the avoided augmentation alternative including:
>> (a) the capital costs;
>> (b) annual operating cost;
>> (c) the total annual net cost of servicing capital expenditure, including financing charges and capital depreciation;
>
> (iii) the long term benefits of the *demand side activity* in terms of its contribution to the deferral or avoidance of other network augmentations;
> (iv) the short and long term reliability benefits of the *demand side activity.*

In determining the prudency or efficiency of *demand side activities* the *AER* must take into account information and analysis contained in the providers' Annual Planning Reports as well as external information on the level of efficient *demand side activities* available in a location appropriate to the constraint or reliability issue that it seeks to address.

4.10.4 How this proposal meets the NEM Objective

Effective prudency reviews that determine whether or not an adequate level of DM has been undertaken provides an important means of oversight and awareness of whether networks are operating efficiently or not. Disallowing revenue for inefficient network capital expenditure provides an important incentive for networks to actively pursue a more adequate level of DM.

4.11 Regulatory Test

4.11.1 The problem

The provisions for the Regulatory Test do not include demand side options as a necessity in any assessment of costs or benefits. For instance, Clause 5.6.5A(c)(8) states that alternative options "may include … demand side management …" (our emphasis). This does not represent the requirement or even encouragement to investigate more efficient solutions, but rather allows the network service provider to consider them on their own, without transparency and without reference to any objective methodology, and only if it chooses to do so. In practice, transmission networks rarely consider DM solutions to network constraints properly or thoroughly. Without the requirement to investigate DM solutions before other options, it is likely that augmentation options will dominate from the beginning, putting DM solutions at a disadvantage.

An additional and related problem is that the Rules give equal weight to "those who produce, consume and transport electricity" (5.6.5A[b][1]). This assumes that the interests of those who produce and transport electricity are aligned with and equal to the long-term interests of consumers. This is not necessarily the case, however, considering the extraordinary waste that occurs from the inefficient and unnecessary consumption of electricity in the NEM. In this context, the push for consumers to use electricity inefficiently is to the benefit of, and is often driven by, generators and networks at the expense of the interests of consumers, who bear the burden of inefficient investments and increased prices.

4.11.2 The solution

To reverse the bias towards augmentation options and the neglect of demand side solutions, it is critical that the Rules specify that DM options must be investigated *before* augmentation options. This is likely to ensure that a more appropriate level of transmission networks' resources and attention are directed to DM before augmentation planning is underway.

The Regulatory Test should not assume that the interests of those who produce, transport and consume electricity are aligned. The Regulatory Test should reflect the NEL Objective by ensuring that the long-term interests of consumers are the priority.

4.11.3 Proposed Rule changes

Change 5.6.5A to:

5.6.5A Regulatory Test

(a) The *AER* must develop and *publish* the *regulatory test* in accordance with this clause 5.6.5A.

(b) The purpose of the *regulatory test* is to first identify *demand side options*, other non-*network solutions* or *new network investment* *alternatives*~~s or non-*network* alternative options~~ that:

(1) maximise the ~~net economic benefit to all those who produce~~long term benefits to consumers; or, ~~consume and transport electricity in the *market*; or~~

Change 5.6.5A (c) (1) to:

(c) In so far as it relates to paragraph (b)(1), the *regulatory test* must:

(1) be based on a cost-benefit analysis of the future (which includes assessment of reasonable scenarios of future supply and demand conditions):

(i) were the ~~*new network investment*~~*demand side option* to take place, compared to the likely alternative option or options,

(ii) were the ~~*new network investment*~~*demand side option* not to take place;

Change 5.6.5A (c) (3) to:

(3) ensure that the identification of the likely ~~alternative~~ *demand side* option referred to in subparagraph (1) is informed by a consideration of all genuine and practicable alternative options to the proposed ~~*new network investment*~~*demand side option* without bias regarding:

(i) cost-reflective pricing, including dynamic pricing

(ii) other demand side activities including

(~~i~~iii) energy source;

(~~ii~~iv) technology;

(~~iii~~v) ownership;

(~~iv~~vi) the extent to which the ~~*new network investment*~~*demand side option* or the ~~non~~ *new* *network* *investment* alternative enables *intra-regional* or *inter-regional* trading of electricity;

(vii) whether it is a *demand side*, *network* or non-*network* alternative;

(viii) whether the *demand side option*, *new network investment* or non-*network* alternative is intended to be regulated; or

(~~vi~~ix) any other factor;

Change 5.6.5A (c) (4) to:

(4) require, for a potential constraint requiring a *demand side activity* ~~*new large transmission network asset*~~in the next 10 years, that the *Network Service Provider* ~~publish~~propose:

(i) cost-reflective pricing, including dynamic pricing

and issue:

(ii) a *request for* *proposals* for ~~information as to the identity and detail of alternative options to~~ the potential *demand side activity*~~*new large transmission network asset*~~; and;

(a) consult with interested parties;

(b) explore the potential for interested party provision of demand side options

(c) engage suitably qualified demand side service providers to assist with the investigation of demand management and publish

(ii) details of the proposed *new large transmission network asset alternative*;

Change 5.6.5A (c) (5) to:

(5) contain a requirement that where there is more than one likely alternative option to the *demand side activity or new network investment*, and no single alternative option is significantly more likely to occur than the other, then the cost-benefit analysis referred to in subparagraph (1) must be undertaken in relation to each such likely alternative option;

Change 5.6.5A (c) (6) to:

(6) not require the level of analysis to be disproportionate to the scale and size of the *demand side activity or new network investment*;

Change 5.6.5A (c) (8) to:

(8) provide that alternative options may include (without limitation) cost-reflective pricing, including dynamic pricing, *generation*, demand side management, other *network* options, or the substitution of demand for electricity by the provision of alternative forms of energy.

4.11.4 How this proposal meets the NEM Objective

DM is currently under-utilised, resulting in inefficient investment in and use of electricity in the NEM. By guaranteeing that DM is properly considered, in a timely manner and at the initial planning stage, this Rule change will assist with the increased delivery of level of DM.

Implementing a more adequate level of DM will increase the efficient *investment in* and *efficient use of* electricity services in the long-term interests of consumers.

4.12 Short-term and long-term price for DM

4.12.1 The problem

There is currently no mechanism for setting the price of demand side response (DSR) activities within the market pool. This is inhibiting the development of a mature DM aggregation market, which could provide extensive network support, facilitate greater efficiency and therefore reduce costs for consumers. DM aggregation businesses are eager to expand however the sector is still largely embryonic due to the lack of a bidding mechanism, with most current activity relating solely to large industrial users. As noted above, Energy Response, a DM aggregation provider has pointed out the lack of support for highly targeted DSR from regulators.[44]

4.12.2 The solution

Setting a price for DM in the market pool will encourage greater investment in DM and facilitate growth of DM aggregation as a market commodity. A market mechanism that provides the opportunity for proponents to bid into the market would encourage new DM entrants; promote competition for existing DM businesses; and make the implementation of DM options easier for network businesses. It would also provide more competition for generators and provide cost-effective DM for networks, which would improve efficiency. The ability to bid into the market pool would allow for a short-term price to be set for DM in peak periods (which would flow on to long-term pricing), while a long-term price would facilitate DM hedge contracts which would compete with contracts for baseload supply.

We suggest there is widespread support across the NEM for development of a bidding mechanism for DM within the NEM. Energy Response has stated that:

> *The potential for DSR to improve the economic efficiency of competitive power markets … is well recognized and understood by market designers, market operators and Government policy-makers around the world."*[45]

The Energy Users Association of Australia also support DSR:

> *An effective DSR operating in response to the NEM will result in significant value to the Australian economy, as it reduces the cost of managing the extreme price volatility in the wholesale market and improves the efficiency of the capital investment in the networks.* [46]

Much as the Rules have directed NEMMCO, "to operate and administer a spot market for the sale and purchase of electricity and market ancillary services" (Cl 3.2.2), to review "the spot market for market ancillary services" (Cl 3.2.2 a1 [2]), and, "the potential future implementation of a usage market for market ancillary services" (Cl 3.2.2 [a1] [3]), the Rules should also direct NEMMCO to review the potential for a market for DM services and make recommendations about its design and implementation.

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[44] Energy Response, *Response to the AEMC Reliability Panel Comprehensive Reliability Review*, 30 June 2006, p. 4

[45] Energy Response, *Response to the AEMC Reliability Panel Comprehensive Reliability Review*, 30 June 2006, p. 2

[46] Energy Users Association of Australia, *Press Release: New report confirms economic benefits to end users of demand side response (DSR) in the electricity market*, 21 October 2005, p. 3

Investigation and implementation of DM is a principle and good practice to achieve maximum efficiency – and not a technology – and therefore does not breach market design principles (3) “avoidance of any special treatment in respect of different technologies …” and (5) “equal access to the market …”

4.12.3 Proposed Rule changes

Insert above 3.1.4 (a):

(1) maximum level of efficiency in the use of electricity, which can be realised through demand management, including its timely and thorough consideration and incentives to encourage its implementation.

Change 3.2.2 to:

NEMMCO must do all things necessary to operate and administer a *spot market* for the sale and purchase of demand management services, both short and long term, and electricity and *market ancillary services* in accordance with this Chapter including:

[Note: The details of the provisions should mirror the details in Clause 3.2.2 for the spot market.]

4.12.4 How this proposal meets the NEM Objective

Creating an effective bidding market for DSR services will encourage its greater uptake, which will deliver more efficient *investment in* and *use of* electricity towards the long-term interests of consumers.

The provision of a DSR market bidding mechanism would allow for greater realisation of DM’s full efficiency benefits, including effects along the supply chain such as reduced requirement for generation; avoidance or deferral of transmission network augmentation; avoidance or deferral of distribution network augmentation; reduction of unnecessary end-user consumption and reduction of unnecessary congestion. All of these have the potential to reduce prices for consumers, and increase reliability of the whole system.

Electricity consumers participating in the DSR activity could benefit directly from revenue provided the DSR action. At the same time, those not participating would also receive a benefit by the reduction of the overall costs of generation and network services.

The DSR bidding trial by the EUAA resulted in a theoretical capacity-weighted bid price from just $1,000/MWh to $1,129/MWh at critical peak demand times, or just over 10% of the value of the NEM Price Cap (VoLL).[47] As the final report noted:

> *This outcome suggests that effective DSR could help create a ‘voluntary’ price cap in the energy market at a value well below VoLL – providing sufficient DSR capacity was available for despatch to impact on the spot price.*

[47] Pareto Associates for EUAA, *Trial of a Demand Side Response Facility for the National Electricity Market: Independent Consultant's Report*, April 2004, pp. vii - viii

In particular, the trial showed that the development of DSR '…would reduce both demand and spot price volatility and lower hedge costs (which are estimated to be between $0.7 and $2.2 billion/year).' [48]

DSR, directly serves the long-term interests of consumers in respect to *reliability of supply* and the *reliability of the national electricity system.* DSR improves both of these aspects of reliability through its capacity to ease specific constraints at times of peak demand, as well as its ability to reduce overall load on the system.

To date, the contribution that DM or DSR can make to reliability has not been explicitly acknowledged within the NEM. For instance, direct load-shedding arrangements with large end users have the potential to significantly ease network constraints during critical peak periods. Increased efficiency of the system, for both baseload and peak loads, will increase reliability overall.

[48] Pareto Associates for EUAA, *Trial of a Demand Side Response Facility for the National Electricity Market: Independent Consultant's Report*, April 2004, p. x

Win, Win, Win:

Regulating Electricity Distribution Networks for Reliability, Consumers and the Environment

Review of the NSW D-Factor and Alternative Mechanisms to Encourage Demand Management

Institute for Sustainable Futures
and **Regulatory Assistance Project**

For

Total Environment Centre

January 2008

This report has been prepared for Total Environment Centre with funding from the National Electricity Consumers Advocacy Panel.

About Total Environment Centre

Established in 1972, Total Environment Centre (TEC**-** www.tec.org.au) is committed to real and effective change to protect the environment and improve society's capacity to be environmentally sustainable. TEC utilises both advocacy and collaboration, and propose solutions.

In its long history of campaigning, policy development and working with the community, TEC has covered a big range of environmental issues **-** city and country; national and state. TEC draws attention to the problem, but also focuses on implementation of solutions through community education and empowerment, new laws, government and business policies and economic instruments.

Over the last five years TEC has created one of Australia's major forums and research programs for corporate social and environmental responsibility – **Green Capital**. This gives TEC the capacity to help mobilise business influence and resources to advance environment protection.

TEC has a longstanding interest in the National Electricity Market and its ability to meet the interests of consumers, in particular energy efficiency and abating global warming. TEC gratefully acknowledges the support of the National Electricity Consumers Advocacy Panel, in funding this project and TEC's other NEM engagements.

About the authors

The **Institute for Sustainable Futures** (ISF**-** www.isf.edu.au) is a research consultancy, and is part of the University of Technology, Sydney. The Institute's mission is to create change towards sustainable futures. Its research promotes public debate and change across a broad range of areas. ISF's aspiration is to support the mainstream adoption of sustainability. Economic, social and environmental research, organisational change theory and innovative economic models that provide a broader perspective on 'value' are important aspects of ISF's work.

Chris Dunstan, Research Principal at ISF, was Project Manager and lead author for this Report.

Kumi Abeysuriya, Senior Research Consultant at ISF, managed the data survey and assisted in drafting this Report.

The **Regulatory Assistance Project (RAP-** www.raponline.org**)**, based in the US, is a non-profit organisation, formed in 1992 by experienced utility regulators, that provides research, analysis, and educational assistance to public officials on electric utility regulation. RAP workshops cover a wide range of topics including electric utility restructuring, power sector reform, renewable resource development, the development of efficient markets, performance-based regulation, demand-side management, and green pricing. RAP also provides regulators with technical assistance, training, and policy research and development. RAP has worked with public utility regulators and energy officials in 45 states, Washington D.C., Brazil, India, Namibia, China, Egypt, and a number of other countries.

Wayne Shirley, a Director of the RAP, has provided expert advice and review and the preface to this Report.

Contents

PREFACE

The electricity sector requires three critical conditions to embrace aggressively cost-effective energy efficiency and other forms of demand-side resources, such as customer-owned generation and demand-side management:

- removal of profit disincentives associated with demand-side resources, by breaking the link between sales volumes and profits – a technique termed "decoupling"
- creation of positive incentives which help to make demand-side resources competitive with supply-side resources in terms of utility profits
- strong public policy leadership, including setting aggressive goals to implement all cost-effective demand-side resources.

Utilities often face strong disincentives for demand-side resources because of their negative impact on profits. Historically, the business model for electric utilities has been built on the simple notion of linking profitability to sales volume – the more energy sold, the higher a company's profits. In regulatory parlance, this is termed the "throughput incentive". Under this business model, a utility has a strong incentive to increase sales and an equally strong incentive to avoid reductions in sales. This incentive is greatly enhanced by the relationship between 1) the opportunity to earn and profit, which is usually tied to the total investment in assets, 2) the fixed nature of the utility cost structure and 3) the relatively high financial leverage of the typical utility's capital structure. These conditions combine to make utility profits extremely sensitive to changes in revenues, such that even a small change in revenues, say 5%, can translate into increases or decreases in earnings of as much as 25–50%.

Were it not for the large impacts of the electric sector costs on the general economy and on the environment, the throughput issue would be little more than an intellectual curiosity – but the electric sector does have large impacts on the economy and the environment. Society has significant policy interests in minimising those costs and impacts. Energy efficiency is widely recognised as the cleanest and most economical way to meet resource needs and reduce emissions. Other forms of demand-side resources, such as load management and customer-owned generation may also be desirable, depending on the chosen technology and its respective cost and emissions profiles. Unfortunately, virtually all demand-side resources have the effect of reducing utility sales and therefore profits. Demand-side resources at the scale necessary to cost-effectively achieve required emissions reductions will most certainly have significant impacts on profits.

It is therefore necessary to address the throughput issue directly by decoupling profits from sales volumes. There are just two fundamental ways to address the throughput issue. One is to restore the net reduction in revenues occasioned by demand-side resources through some revenue adjustment. The existing ***NSW "D-factor"*** is a form of this type of decoupling. The D-factor attempts to address this problem by restoring revenues lost due to demand management. This approach, however, can be cumbersome to implement, because it requires extensive measurement and verification to track the revenue changes from utility-administered efficiency programs. This can lead to disputes over methodology and D-factor calculations may be subject to gaming on the part of the utility. The D-factor also fails to capture the effects of customer-initiated energy efficiency, which may provide the utility an incentive to obstruct all demand-side resources which are not part of its own demand management programs. Perhaps most importantly, the D-factor fails to break the link between throughput and profits, leaving the same incentives in place as exist under the traditional business model.

The alternative approach is to implement a mechanism that automatically adjusts prices to reflect all changes in sales. The most effective decoupling methodology uses ***a revenue cap*** approach which stabilises the utility's revenues between changes in the base tariff levels. Properly designed, this method uses the utility's billing information, which ordinarily is not subject to any meaningful dispute, to recalculate prices periodically to maintain either a constant revenue level or a variable, but easily determinable, revenue level linked to an independent factor such as economic growth or numbers of customers. This method fully decouples profits from sales and frees the utility to pursue all cost-effective demand management, without endangering profits.

The second critical issue is the creation of positive incentives for demand management. Even with decoupling in place, utilities and their managers require a business model which puts demand management on an equal footing with supply-side resources. In the absence of an incentive structure to reward cost-effective demand-side resources, utilities will continue to have a significant bias in favour of traditional "wires and turbines" solutions. Some incentive mechanism, such as rewarding the utility with a share of the savings from demand management, is required to meet this need. This is quickly becoming the accepted approach in many jurisdictions in the US and has been demonstrated to be effective.

Finally, governments and regulators must provide a clear signal to the electric sector that all environmentally safe cost-effective demand-side resources should be deployed before the use of traditional fossil-fuel supply-side resources. This may require the setting of specific goals for reductions in demand. By creating a clear public policy expectation and enabling utilities with appropriate incentives and removal of disincentives, regulators can change the current path of the electric sector. The recommendations of this report outline the first steps to be taken on that path, but they are by no means the end of the process. Implementation requires steady guidance which can only be provided by regulators and policy makers, using the recommendations of this report as its foundation.

Wayne Shirley
Director
The Regulator Assistance Project, USA

EXECUTIVE SUMMARY

Demand Management (DM) refers to measures undertaken by a utility business to meet customer needs by shifting or reducing demand rather than by increasing supply. While DM has the potential to reduce costs for both utilities and their customers, the take up of DM depends heavily on the incentives and disincentives created by the way utilities are regulated. Australia's electricity sector regulators and policy makers have to date failed to create regulatory frameworks that deliver efficient outcomes in relation to demand management. As a consequence, electricity utilities are spending more on energy supply infrastructure than necessary, which means higher electricity bills for consumers. The regulatory neglect of efficient demand management has also led to unnecessarily high consumption of electricity and therefore higher greenhouse gas emissions.

The positive aspect of this past regulatory and policy failure is that there remains a large reserve of cost-effective DM potential within Australia that has yet to be tapped. By removing the regulatory barriers to DM, there is scope to reduce costs to consumers and reduce greenhouse gas emissions, while maintaining or even improving reliability of power supply – that is, there is a real prospect of delivering a "Win-Win-Win" solution.

Consideration of regulatory reform in relation to DM is particularly timely now for two reasons. First, we are now moving from state-based to national economic regulation of electricity distribution network businesses (Distributors) by the new Australian Energy Regulator (AER). This provides an unprecedented opportunity to redress past shortcomings in regulating Distributors. Second, given the widespread community concern about climate change, there is renewed interest in the scope of DM and energy efficiency to provide low-cost options to reduce greenhouse gas emissions.

In order to consider what regulatory reform is needed, this Report focuses on the most comprehensive attempt in Australia to date to remove the regulatory barriers to DM: the NSW "D-factor". The D-factor ("D" for Demand Management) was introduced by the Independent Pricing and Regulatory Tribunal of NSW (IPART – the NSW economic regulator) in 2004 in order *"to ensure that these regulatory barriers* [to DM] *are removed,"*

The D-Factor operates by allowing Distributors to increase their prices slightly to recover any loss of revenue arising from lower energy sales as a result of Distributors undertaking DM measures. The D-factor also allows the Distributors to recover the direct cost of undertaking DM measures, provided this does not exceed the value of savings in network costs due to the measures. In principle, the D-factor will always benefit consumers because, in the short term, the price increase due to the Distributor's recovered lost revenue is much lower than the retail price of electricity saved by the consumer, and in the longer term, the cost of the DM measure is lower than the network costs avoided. In addition, the D-factor encourages energy savings that avoid both the environmental costs associated with greenhouse gas emissions and the financial costs associated with adapting to and offsetting these emissions.

Outcomes of D-factor

This Report concludes that although the D-factor is an important precedent in supporting DM and should be built upon, the D-factor is not a cure-all for DM and, without reform and complementary measures, it is very unlikely to deliver an efficient level of DM activity.

The available evidence indicates that, compared to past NSW and current interstate practice, the D-factor has been successful in stimulating greater consideration and implementation of DM by NSW Distributors. It is estimated that new DM measures implemented by the three NSW

Distributors following the creation of the D-factor delivered a reduction in peak demand in NSW of 29.4 MVA in 2004/05 and a further 12.4 MVA in 2005/06. This is equivalent to about 7% and 3% respectively of the average annual growth in summer peak demand in NSW. The cost to the Distributors of undertaking these DM measures was reported as $5.1 million, while the expected avoided network cost was reported as $19.3 million. This represents a very attractive benefit-cost ratio of 3.8 to 1; that is, Distributors reported savings of $3.80 for every $1 they spent on DM. This suggests that there are very significant further cost-effective DM opportunities that have yet to be tapped.

However, there are two major caveats on this conclusion.

Firstly, the D-factor can only be regarded as a qualified success as the amount of DM undertaken since it was created is modest, particularly in comparison to some overseas jurisdictions, and varies widely across the three NSW Distributors. The total DM expenditure reported by NSW Distributors in relation to the D-factor is equivalent to just 0.13% of the Distributors' revenue. As a share of utility revenues, this is less than one fifth as much DM expenditure as is funded by the average utility in the US. The leading utilities in the US spend much more than this average level.

Secondly, the extent of *increase* in DM implementation is very difficult to establish, as there does not appear to be reliable information available on the level of DM implementation by Distributors prior to the introduction of the D-factor in 2004/05. Ironically, this caveat reflects a successful feature of the D-factor, in that it has, for the first time, led to a reasonably robust and consistent framework for Distributors to report DM implementation. However, improvements in the reporting framework are urgently required.

Efficient Regulation for DM

An efficient regulatory structure for DM requires more than just a "D-factor" type mechanism. Critical elements in an efficient regulatory structure include:

- Short-term incentives relating to the annual price control formula within regulatory periods. These incentives created by the "form of regulation" should be neutral between DM and network investment options, and should decouple Distributor profit and revenue from electricity sales.
- Long-term incentives between regulatory periods created by the processes of assessing the "prudence" of investment and incorporating new assets into the Distributor's asset base. These should be neutral between DM and network investment options in terms of recovery of costs and sharing of efficiency benefits between shareholders and customers.
- Planning and development regulations. These should ensure that there is equal opportunity for DM and network investment options to be both considered and adopted.
- Regulation should also ensure that Distributors' planning and operational decisions take account of external environmental costs and in particular, the costs associated with greenhouse gas emissions.

These are the minimum elements to ensure a balanced regulatory environment. However, even a balanced regulatory structure may not ensure a timely and efficient take up of DM. Cultivated by the long-standing regulatory bias against DM, there are a number of other non-regulatory barriers to DM. These barriers include:

- Distributor organisational culture, expertise and conventions that has focused on infrastructure-based solutions.

- Low awareness of, and lack of familiarity with, DM options and an associated perception among Distributors and their customers that there is a high risk associated with DM.
- The relatively undeveloped state of the industry for supplying DM options and the associated relative lack of both economies of scale and efficiencies of market competition.
- The absence of an effective market price on greenhouse gas emissions.

Therefore to encourage an efficient uptake of DM in the short term, it is prudent to provide deliberate positive incentives at least for an interim period in order to address this market failure and to "kick-start" the DM industry. Such positive incentives could be either within or outside the regulatory structure.

As part of its regulatory determination, IPART recognised this principle of providing positive incentives by:

- including in the D-factor not just the value of electricity sales "foregone", but also the direct cost of the DM initiatives, and
- allowing Distributors to retain the value of avoided capital investment due to DM.

IPART considered this a "generous" treatment of DM and stated, "This generosity is warranted, at least in the short term, to help overcome the barriers to the greater use of demand management solutions in supplying network services and to support the emergent market for these solutions." (IPART 2007, p.89).

Beyond Regulation

Given the non-regulatory barriers to DM, an efficient and timely uptake of DM is likely to require more than just a supportive regulatory structure. The formal regulatory structure should be complemented by other policy mechanisms, such as:

- a clear Government policy statement about the importance of DM
- regular, robust and consistent public reporting of the DM performances of Distributors
- detailed and timely public information about network capacity and emerging constraints
- funding and facilitation to accelerate the development DM capacity (such as through a "DM Fund").

In recognising both the large potential for DM and the barriers to its adoption, some jurisdictions such as California have established an explicit "loading order". This loading order prioritises new resources with all cost-effective energy efficiency first, followed by demand-side response, renewable energy, strengthening network interconnection and then finally fossil-fuel plants (limited to emissions profile of a combined-cycle gas turbine power station).

The following recommendations to reform and complement the D-factor are intended to address the barriers to DM and thereby create a more level playing field for the efficient development of DM in Australia.

Recommendations:

1. **Clarify government policy intent regarding efficient Demand Management.**

   In recognition of the scope of demand management (DM) both to advance the long-term interests of consumers and to enhance environmental sustainability, State, Territory and

Federal Governments should ensure that the National Electricity Law and the National Electricity Rules:

- explicitly require the Australian Energy Regulator (AER) to make efficient regulatory determinations in relation to DM
- explicitly require Distributors to undertake all cost-effective DM, prior to network augmentation.

2. Align network incentives with consumer and public interest.

In making regulatory determinations, the AER should avoid creating incentives that set the financial interests of the Distributors in conflict with the interest of their customers. In particular, incentives against DM should be avoided in relation to:

- short-term incentives (within regulatory periods) associated with price/revenue control formulae (see Recommendations 3 to 8)
- long-term incentives (between regulatory periods) associated with prudence review and the incorporation of capital expenditure into the capital base and mechanisms for sharing efficiency benefits between shareholders and consumers (see Recommendations 9 to 11)
- network system development and planning requirements (see Recommendations 12 and 13).

3. "Decouple" Distributor profit from electricity sales.

In setting its year-to-year price control formula, the AER should as a key priority, decouple Distributor revenue and profit from electricity sales volume. That is, the AER should ensure that the profitability of a Distributor is not linked to the amount of electricity carried through its network and consumed by its customers.

4. Use Revenue caps to decouple network profit from electricity sales.

In order to decouple electricity consumption and Distributor revenue and profitability, the AER should apply a revenue cap in preference to a price cap in regulating Distributors.

5. Link revenue cap to economic growth.

In applying a revenue cap, the AER should consider applying adjustment factors to insulate Distributors from large divergence of actual peak demand from forecast peak demand. This could, for example, be applied by linking the annual revenue cap to movements in measures of economic activity, such as Gross State Product.

6. Use D-factor if revenue cap precluded.

In circumstances where it is not possible to apply a revenue cap (for example, where a commitment to a price cap has already been made, as in NSW for the forthcoming regulatory period), other revenue decoupling or "lost revenue adjustment" mechanisms should be applied (such as the NSW D-factor).

7. **Create a “use it or lose it” component in the D-factor.**

   Where a “lost revenue adjustment” mechanism (such as the D-factor) is established, it should be applied with a default ex ante allocation on a “use it or lose it” basis that assumes some (non-trivial) level of DM will be undertaken by the Distributor. A D-factor of at least 2% of annual proposed capital expenditure could provide a reasonable default ex ante allocation.

8. **Allow recovery of long-term DM costs in D-factor.**

   Distributors should be permitted to recover, through the D-factor, costs associated with low cost “long-term DM” opportunities that would otherwise be lost if they are delayed until a local network capacity constraint emerges.

9. **Allow Distributor savings from DM to be carried forward.**

   The AER should ensure that Distributors are permitted to carry over efficiency benefits from DM, such as deferral or avoidance of capital expenditure, from one regulatory period to the next, on no less favourable terms than they are able to continue to earn a return on network capital investment from one period to the next.

10. **Ensure balanced prudence review of capital expenditure.**

    Recognising that short-term incentives are likely to have little impact unless complemented by longer-term incentives, the AER should ensure that the review of prudence of past and projected capital expenditure involves a thorough all-sources assessment of the opportunities for deferring capital expenditure through DM, conducted by experts with a demonstrated balanced understanding of the theory and practice of DM.

11. **Require Distributors to demonstrate efforts to procure DM.**

    The AER should require Distributors to demonstrate that they have undertaken reasonable efforts to identify and procure cost effective DM, particularly in the context of anticipated network constraints and proposed new network investment. Such efforts should include DM direct offers to consumers, DM programs developed by the Distributor and DM proposals solicited from other parties.

12. **Inform the DM market.**

    The AER should seek to inform the market for DM options by requiring Distributors to publish detailed information annually about the current capacity of the distribution network, current and projected demand and possible options to address any emerging constraints. (The NSW DM Code of Practice for Distributors and the South Australian Guideline 12 provide sound precedents for such information disclosure.)

13. **Ensure consistent Distributor DM performance reporting.**

    The AER should require Distributors to report annually on DM activities undertaken in relation to: expenditure, peak demand and energy consumption reductions, value of electricity sales foregone, value of capital and operating expenditure avoided or deferred, and efforts to identify and procure cost effective DM. Such reports should be publicly available. The AER should issue a pro forma to encourage consistency in DM reporting. Reporting to the AER should be harmonised with any other DM reporting requirements.

14. Conduct and publish annual AER DM Reviews.

In recognition of the relatively underdeveloped state of DM in Australia, the AER should monitor DM data provided by Distributors and publish a consolidated annual review to encourage mutual learning and allow comparison of different policies and approaches between jurisdictions. (This will also assist in building understanding of DM potential within the regulatory community and among stakeholders.)

15. Apply complementary transitional measures to accelerate DM.

Recognising that the above measures are designed simply to address existing barriers to efficient DM in the economic regulatory environment, and that the DM market in Australia is currently underdeveloped, Federal, State and Territory Governments should establish complementary transitional measures to create positive incentives to develop DM quickly.

16. Put an appropriate price on greenhouse gas emissions.

In the interests of economic efficiency, and in recognition of the high economic cost that climate change is expected to impose on the Australian and global community, the Australian Government should ensure that the price of greenhouse gas polluting activities, such as fossil fuel-based electricity generation, includes the full cost of the associated greenhouse gas emissions. This could be achieved by introducing an emissions trading scheme or a carbon tax. (Recommendations 1 to 14 would be complementary to such action.)

1 INTRODUCTION

Around the world, the electricity supply industry is facing a contradiction between, on the one hand, long-standing institutions established to focus on providing adequate supply capacity, and on the other hand, the need for a massive improvement in end-use energy efficiency to reduce greenhouse gas emissions. Electricity "Demand Management" has emerged over the past 25 years as a potential solution to this contradiction.

A major recent report by the International Energy Agency highlights this contradiction by estimating that energy efficiency can be expected to account "for between 45% and 53% of the total CO_2 emission reduction relative to the Baseline" in order to return the world's greenhouse gas emission to current levels by 2050 (IEA 2006). A similar study focused on Australia, which considered an "enhanced technology scenario" which involved Australia's greenhouse gas emissions falling below 2004 levels by 2050, projected that energy efficiency would contribute 55% of emissions abatement at 2050 (Gurney et al. 2007).

What is demand management?

Electricity "demand management" (DM), involves electricity utilities investing in helping consumers to reduce their demand for power. As a rapidly evolving field globally, there is some confusion in how terms like "demand side management", "distributed generation", "demand response" are used. This Report adopts the broader definition of demand management as "measures undertaken by a utility business to meet customer needs by shifting or reducing demand rather than by increasing supply". This includes a broad range of demand management activities including energy efficiency, load management, interruptible load and distributed generation.

Demand management and network regulation

Electricity Demand Management represents arguably the world's largest and cheapest pool of potential greenhouse gas emission abatement. However, DM currently plays a small role in the electricity sector in Australia. The use of DM as an alternative to electricity network investment has been retarded by, among other things, economic regulatory incentives that encourage sales growth and discourage energy efficiency and optimal use of existing network assets.

In particular, the widespread use of regulated price caps for distribution networks has created major financial barriers to network businesses undertaking DM. This is despite in-principle support for DM from governments and regulators. The transfer of responsibility for the economic regulation of distribution network businesses from state-based regulators to the Australian Energy Regulator creates a unique opportunity to get the regulatory incentives right and deliver a "win, win, win" outcome for consumers, the environment and network owners.

The importance of demand management

Federal, State and Territory Governments have recently recognised that redressing these barriers is not just a matter of economic efficiency and competitive neutrality, but also a primary element in the urgent task of reducing Australia's growing greenhouse gas emissions.

In the current Review of the National Electricity Regulation, the Council of Australian Governments (COAG) made clear its intention to remedy this situation, when it agreed,

> to improve the price signals for energy investors and customers by: …
>
> c) implementing a comprehensive and enhanced MCE [Ministerial Council on Energy] work program, from 2006, to establish effective demand side response mechanisms in the electricity market, including network owner incentives, effectively valuing demand-side responses, regulation and pricing of distributed and embedded generation, and end user education (COAG 2006).

After over a decade of electricity reform, and despite some attempts by regulators to address DM, particularly in New South Wales and more recently in South Australia, the long-recognised regulatory barriers to network DM are yet to be effectively addressed.

What is the D-Factor?

The NSW "D-factor" is the most comprehensive attempt in Australia to date to remove the regulatory barriers to DM. The D-factor ("D" for Demand Management) was introduced by the Independent Pricing and Regulatory Tribunal of NSW (IPART – the NSW economic regulator) in 2004 in order *"to ensure that these regulatory barriers [*to the use of demand management options*] are removed, and to neutralize the potential disincentives for demand management created by the change to a weighted average price cap form of regulation (which links revenue to volume sold)."* (IPART 2004, p. 89)

The D-Factor operates by allowing Distributors to increase their prices slightly to recover any loss of revenue arising from lower energy sales as a result of their undertaking DM measures. The D-factor also allows the Distributors to recover the direct cost of undertaking the DM measure, provided this does not exceed the value of network costs avoided due to the measure. In principle, the D-factor will always benefit consumers because, in the short term, the price increase due to the Distributor's recovered lost revenue is much lower than the retail price of electricity saved by the consumer, and in the longer term, the cost of the DM measure is lower than the network costs avoided. In addition, the D-factor encourages energy savings that avoid both the environmental costs associated with greenhouse gas emissions and the financial costs associated with adapting to and offsetting these emissions.

Purpose and background of this Report

With funding assistance from the National Electricity Market Advocacy Panel, the Total Environment Centre (TEC) commissioned this Report to review the NSW 'D-factor' mechanism and consider what reform is needed to remove the regulatory barriers to DM in Australia. The context for the project is to ensure that when regulation of electricity distribution network service providers is transferred to the national level from 2008, it incorporates appropriate and effective incentives for DM.

This Report aims to highlight the above issues and to encourage the new regulators (the Australian Energy Regulator and the Australian Energy Markets Commission which is responsible for setting the regulatory rules) to avoid the mistakes of the past.

For a robust debate to occur, it is essential that the implications of different regulatory options for DM are well understood by both regulators and stakeholders.

This Report assesses the effectiveness of the D-factor and considers its alternatives and the role of complementary measures in encouraging DM. It also compares and contrasts D-factor theory and practice with other instruments intended to support DM.

"Price-based DM" versus "Active DM"

There are two broad approaches that Distributors can adopt to encourage DM. These are:

- "Price-based" or "tariff-based" DM which involves adjusting the structure of prices to reflect supply capacity constraints within the network. "Time of use" pricing which raises electricity prices at times of peak demand and network capacity constraints and lowers prices at other times, encourages consumers to change their pattern of electricity use. This approach to DM is crucial for reducing peak demand and deferring the need for new network and power station infrastructure, but generally does little to reduce overall energy consumption and associated greenhouse gas emissions. Apart from addressing inefficient pricing structures, price-based DM adopts a "passive" approach to DM as it leaves decisions about energy use up to the consumer and does not engage with the consumer directly to address other barriers to DM.

- "Non-tariff based" or what might be called "Active" DM which involves engaging with the consumer to change their energy using behaviour. This could be through offering cash or other incentives, assisting in identifying consumer energy saving opportunities, providing services and equipment to reduce demand, information and education programs, community based energy saving schemes. Such Active DM initiatives can be targetted at reducing either peak demand or overall energy consumption.

These two approaches are complementary. Successful DM strategies are likely to include elements of both. Time of use pricing and "smart meters" could, in principle, play a useful role in encouraging greater energy efficiency, but in practice Distributors have yet to claim any such energy savings through their D-factor submissions. The reforms proposed in this report would increase the likelihood of such energy savings being delivered.

The focus of this report is on this "non-tariff-based" DM or active DM, and in particular on DM measures that reduce the total amount of energy delivered and consumed and therefore the amount of greenhouse gases emitted. The D-factor was established primarily to encourage this form of DM.

Research method

This study started with a literature review to identify any relevant past work and gaps in existing knowledge. Performance data on DM was sought from IPART and the NSW Department of Water and Energy. A survey was designed to collect data on outcomes of the NSW D-factor from distribution network businesses. Comparable data was also sought from other states for benchmarking the NSW review. A proactive approach was taken to data collection including meetings, and telephone follow up as necessary in order to gather data which was as credible and as thorough as possible.

In practice, the only data that was available from the NSW Distributors was that which had been previously reported either directly to IPART or publicly through the Annual Network Management Reports.

A series of telephone and face-to-face interviews were undertaken with Distributors' officers involved in managing DM. A Review of the current status of Regulatory Incentives for DM in Australia was undertaken to provide an overview of the current differing regulatory structures in key Australian national electricity market jurisdictions (including NSW, Victoria, South Australia and Queensland) in relation to the treatment of DM.

Processes for developing Regulatory incentives for DM were reviewed, focusing on current processes guiding the development of the national regulatory framework. This review identified opportunities for influencing these processes to achieve a more equitable and efficient treatment of network DM in the national regulatory framework to be administered by the Australian Energy Regulator (AER).

Recommendations were drafted regarding practical steps to establish effective and efficient regulatory incentives for DM for network businesses within the national regulatory framework.

The US Regulatory Assistance Project provided a broader context of demand management regulation overseas, guiding our thinking and research, as well as enabling a review and quality check.

2 DISTRIBUTION NETWORKS, ECONOMIC REGULATION AND DM

Electricity networks are generally regarded as natural monopolies and therefore are usually subject to economic regulation in place of market competition. Over the past fifteen years, the regulation of electricity distribution network businesses ("Distributors"[1]) in Australia has become more formalised; moving from an administrative model with more or less direct political oversight to a more "corporatised" model of public and private corporations regulated by independent statutory regulatory agencies. While formal regulatory agencies were established in most states of the USA in the early 20th century (Troesken 1992) this approach to regulating networks only took hold in Australia in the 1990s as part of the transition to corporatised (and in some cases, privatised) electricity utilities. This trend was strongly influenced by the example of the United Kingdom in the establishment of the Office of the Electricity Regulation (OFFER) in 1989.

Consequently, the whole discipline of economic regulation of electricity networks is still at a relatively early stage of evolution, particularly in Australia. Many of the conventions, norms and traditions that have been established in this area are recent developments and draw on a relatively narrow set of institutional precedents.

The assumption that electricity networks are natural monopolies often confuses related but separate aspects of networks. The role of the planner and procurer of networks services within a given geographical area is by definition a monopoly role. On the other hand, building or reinforcing the network itself is not a pure monopoly in that there clearly are technical alternatives in the form of DM solutions that could compete with it. However, for DM to compete effectively it requires that the Distributor, in its role as the monopoly planner and procurer of networks services, facilitates competition between itself as owner and builder of network infrastructure and providers of DM services. This creates a strong potential for Distributors to be biased in favour of investment in their own network and against DM.

One response to this dilemma is to separate the role of network planner from that of network owner/manager. However, this functional separation is likely to create further inefficiencies. The alternative is to ensure that economic regulation both minimises the incentives for such bias and establishes a framework in which any such bias can be detected and corrected. Yet economic regulation of distributors in Australia has frequently created exactly the opposite situation. It has discouraged competition between DM and network infrastructure and it has not established the transparency required to expose this lack of competition

A common theme of the development of regulation of electricity networks over the past fifteen years has been the desirability of "performance-based regulation" or "incentive regulation". This is regulation that rewards desirable behaviour or performance and/or penalises undesirable behaviour or performance. Common objectives that have been targeted in relation to this incentive regulation include reliability, network losses, etc. However, it has also been observed that "all regulation is incentive regulation" (Crew 1996, pp. 211–225) in the sense that any application of regulation will inevitably create incentives, deliberate or inadvertent, productive or perverse, that encourage or discourage various outcomes.

One of the most prominent perverse incentives that has been created is to discourage DM, even when it would lead to more efficient networks and lower costs to consumers.

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[1] Sometimes also known as "Distribution Network Service Providers" (DNSPs) or simply "Distribution Businesses" (DBs)

Efficient Regulation for DM

Electricity networks are primarily designed to meet the maximum likely peak demand, so the cost of providing network services is dominated by the capital investment in network infrastructure required to provide capacity to meet peak demand.

The manner in which Distributors earn regulated financial returns on this network investment strongly influences investment risk on network assets, Distributor behaviour and the attractiveness of alternative DM solutions.

Critical elements in an efficient regulatory structure include:

- Short-term incentives relating to the annual price control formula within regulatory periods. These incentives created by the “form of regulation” should be neutral between DM and network investment options, and should decouple Distributor profit and revenue from electricity sales.
- Long-term incentives between regulatory periods created by the processes of assessing the “prudence” of investment and incorporating new assets into the regulated asset base. These should be neutral between DM and network investment options in terms of recovery of costs and sharing of efficiency benefits between shareholders and customers.
- Planning and development regulations. These should ensure that there is equal opportunity for DM and network investment options to be both considered and adopted.
- Regulation should also ensure that Distributors’ planning and operational decisions take account of external environmental costs and in particular, the costs associated with greenhouse gas emissions.

These elements are considered below.

Form of regulation and “decoupling”

Network economic regulation can broadly be divided into price cap and revenue cap forms.

Under the price cap form of regulation, the regulated network business is subject to a maximum price per unit of electricity (for example, 10 cents per kilowatt-hour). This cap lasts for the term of the “regulatory period”, typically three to five years. Within this period, the more units of electricity supplied, the higher the network business’s revenue. As network costs tend to be dominated by large fixed capital costs, and relatively low operating costs, this means that the additional revenue from each additional kilowatt-hour supplied will tend to far exceed the additional costs of supplying it and therefore delivers significant additional profits. The same principle works in reverse. If the quantity of electricity sold is a little less than expected, then the profit of the Distributor can be a lot less than expected. In these circumstances, it is not surprising that Distributors would be reluctant to investment in DM that reduces their sales and therefore significantly reduces their profit.

By contrast, under a revenue cap form of regulation, the total allowable revenue is fixed in advance for the regulatory period (for example, $1 billion per annum). In this case, if more units of electricity are sold, then the unit price of electricity must be reduced to stay within the revenue cap. Adopting a revenue cap breaks the link between electricity sales and Distributor profit. In other words, it decouples higher kilowatt-hour sales volume from higher profits (Moskovitz 1989).

Alternatively, where a price cap is employed, other regulatory adjustments can be applied to decouple sales volume from profit. Such decoupling mechanisms date back as far as the Electric Revenue Adjustment Mechanism (ERAM) introduced in California in 1978 (Moskovitz 1989).

There are pros and cons for each form of regulation and there are also hybrid variants that combine aspects of each (Jamison 2005). However, the relevance of price cap regulation here is the perverse incentive it creates for the network businesses to gain extra revenue and profit by encouraging increased consumption, and conversely, the loss of revenue and profit associated with encouraging customer energy savings and DM.

As the renowned sustainability expert Amory Lovins has observed,

> The most profoundly important regulatory change to support distributed generation and efficient end-use is also the simplest: decouple utility revenue requirements and profits from kWh sold. This decoupling of revenues from sales… fundamentally changes the incentives and hence the culture of regulated utilities. Regulated utilities should be rewarded not for selling more kWh, but for helping customers get desired end-use services at least cost (Lovins et al. 2002, pp. 333–334).

Return on investment and prudence review of network expenditure

While decoupling revenue from sales in the form of regulation addresses the short term disincentive within each regulatory period, Distributors will still be unlikely to invest in DM if investments in DM offer a lower medium- to long-term financial return than investment in network infrastructure. These longer-term financial returns are mainly dependent on the decisions by the economic regulator at the regulatory determination or "reset" at the beginning of each regulatory period (typically 4 to 5 years in Australia). The two key determinants for the financial return are how much investment Distributors are allowed to earn a return on (i.e. the "regulatory asset base" or "RAB") and the allowed rate of return. While there are endless arguments about these issues, what matters here is how these determinants of financial return treat DM differently to network investment.

Before any new expenditure by Distributors can be recovered through electricity charges, it is subject to a "prudence review" commissioned by the regulator. To date in Australia, these prudence reviews have generally been contracted out to engineering and economic consultants who have a strong expertise in electricity network development and little expertise in DM. Distributors generally know from experience that if they invest in new network capacity, then unless there is strong evidence to the contrary, the regulator will deem the investment to be "prudent", and allow it to be included in the Distributor's "regulatory asset base". This means they will be permitted to recover the capital cost plus a return on investment from their customers. Furthermore, since network investment tends to be "lumpy", that is, it tends to take place in large, infrequent increments that are designed to meet many years of expected demand growth, Distributors typically earn a return on the whole investment from the moment that any part of it is deemed prudent.

By contrast, DM expenditure typically takes place in much smaller increments that are only sufficient to a meet a year or two of demand growth at a time. DM is also more likely to consist of operating expenditure rather than capital expenditure. Moreover, most Distributors have little experience of recovering the cost of investments in DM from their customers. Even where the regulator explicitly allows the direct cost of DM to be recovered, unless this includes a return on DM "investment", the network business may still prefer investment in traditional network assets from which they are able to earn a regulated financial return.

In NSW, IPART has sought to balance the financial incentives of investing in, and earning a return on, network infrastructure versus DM operating expenditure by allowing the Distributors to retain the benefits of avoided capital costs (that is, avoided interest, return on investment and depreciation) within the regulatory period.

However, Distributors are likely to hesitate to undertake DM expenditure in one regulatory period where it leads to avoided or deferred network investment in the following regulatory period unless there is explicit recognition of and compensation for this. In the absence of such recognition and compensation, the Distributor is much more likely to choose the "safer" option of investing in the network capacity both in the current and the next regulatory periods.

In order to provide balanced longer-term incentives for cost-effective DM solutions, it is therefore essential for the regulator to ensure the following:

1. That Distributors are able to recover expenditure on DM as easily and predictably as expenditure on traditional network infrastructure and operation.
2. That Distributors are able to earn a return on prudent DM investment equivalent to the returns on investment in traditional network infrastructure.
3. That Distributors are able to retain and carry over from one regulatory period to the next, the benefits of DM deferring network capital expenditure. (just as Distributors network capital investment in one regulatory currently continues to earn returns on investment in the next period).
4. That the review of prudence of traditional network expenditure considers on an equal basis to network investment, the potential for Distributors to defer or avoid such expenditure through DM.

Positive incentives for DM

The above measures are required to create an efficient economic regulatory structure for DM. However, even a balanced regulatory structure may not ensure a timely and efficient take up of DM. Cultivated by the long-standing regulatory bias against DM, there are a number of other barriers to DM outside of the economic regulatory structure. These barriers include:

- Distributor organisational culture, expertise and conventions that has focused on infrastructure-based solutions.
- Low awareness of, and lack of familiarity with, DM options and an associated perception among Distributors and their customers that there is a high risk associated with DM.
- The relatively undeveloped state of the industry for supplying DM options and the associated relative lack of both economies of scale and efficiencies of market competition.
- The absence of an effective market price on greenhouse gas emissions. (While this is of course a crucial economic element of regulation, economic regulators in Australia have deemed this a matter for policy to be determined by Government. The NSW and ACT Governments have partially addressed this issue through the establishment of the Greenhouse Gas Abatement Scheme. The new Federal Government has a policy commitment to create a market price on greenhouse emissions by establishing an emissions trading scheme by 2010.)

Given these barriers to efficient uptake of DM, it is prudent to provide deliberate positive incentives at least for an interim period in order to address this market failure and to "kick-start" the DM industry. Such positive incentives could be either within or outside the regulatory structure.

As part of the current regulatory determination, IPART recognised this principle of providing positive incentives by:

- including in the D-factor not just the value of electricity sales "foregone", but also the direct cost of the DM initiatives, and
- allowing Distributors to retain the value of avoided capital investment due to DM.

IPART considered this a "generous" treatment of DM and stated, "This generosity is warranted, at least in the short term, to help overcome the barriers to the greater use of demand management solutions in supplying network services and to support the emergent market for these solutions" (IPART 2007, p.89).

Given the non-regulatory barriers to DM, an efficient and timely uptake of DM is likely to require more than just a supportive regulatory structure. The formal regulatory structure should be complemented by other policy mechanisms, such as:

- a clear Government policy statement about the importance of DM.
- regular, robust and consistent public reporting of the DM performances of Distributors.
- detailed and timely public information about network capacity and emerging constraints.
- funding and facilitation to accelerate the development DM capacity (such as through a "DM Fund").
- an effective market price on greenhouse gas emissions.

Distribution network regulation in NSW

The barriers to DM created by traditional price cap regulation of network businesses have been recognised in Australia for many years. In 1994, The Government Pricing Tribunal of NSW (which later became IPART) stated,

> *Various studies have suggested that there is considerable scope for cost-effective demand management. This underutilised potential has led to a focus on possible reasons as to why the market fails to deliver cost-effective DM…*
>
> *The problem may not be the failure of the market in energy management services but rather that the regulatory framework has prevented its development…*
>
> *Both price caps and rate of return regulation introduce a bias against DM. Under these regulatory approaches the [Electricity Supply Industry] has a financial incentive to sell more electricity rather than demand management services – even where DM may reduce the total costs of meeting the customer's energy needs* (Government Pricing Tribunal of NSW 1994a).

To overcome these barriers to DM in NSW, mechanisms have been applied to encourage electricity distributors to invest in cost-effective demand management solutions since 1994 (Government Pricing Tribunal of NSW 1994b).

In relation to the form of regulation, the NSW economic regulator, the Independent Pricing and Regulatory Tribunal (IPART) has in the current regulatory determination (2004/05 to 2008/09) replaced the previous revenue cap with a (weighted average) price cap (IPART 2007). However, IPART has established three mechanisms to address the perverse short-term incentives against DM created by a price cap.

Firstly, to partially decouple Distributor sales volume from revenue (and profit), IPART has introduced a "D-factor" to enable distributors to raise prices to compensate for electricity sales revenue lost, or "foregone" as a result of DM initiatives. The summary of the rationale for the D-factor as described by IPART is included in **Appendix 2**.

Secondly, the D-factor allows the distributors to recover through network charges the direct cost of the DM measures up to a maximum value of the avoided network infrastructure costs deferred or avoided. However, the Distributors can only recover both these costs elements two years after they have been incurred, following formal assessment and approval by IPART[2].

[2] The details for the application of the D-factor are described in the *Guidelines on the Application of the Tribunal's Demand Management Determination* http://www.ipart.nsw.gov.au/investigation_content.asp?industry=2&sector=4&inquiry=68

The third mechanism to address regulatory barriers to DM is to allow the Distributors to retain any net capital and operating cost savings flowing from DM measures for the remainder of the regulatory period. This is achieved by simply allowing the Distributor to continue to charge the same anticipated prices, notwithstanding the cost savings deriving from DM. However, while the de facto recognition of these savings by the regulator may offer some reassurance to the Distributors within the regulatory period, this does not provide any guarantee about carrying over such benefits from one regulatory period to the next. In other words, a Distributor may avoid DM towards the end of regulatory period for fear of reducing their case to the regulator to undertake capital expenditure and earn a financial return on this investment in the next regulatory period.

At first glance, these three mechanisms appear to remove the short-term financial disincentives to the distribution network businesses undertaking DM. However, as noted above, some significant risks and barriers remain, particularly in relation to the longer-term incentives regarding prudence review and carrying over the benefits of DM from one regulatory period to the next. Nevertheless, this is a significantly better system of incentives than the simple price cap regulation that exists in many other jurisdictions around the world including Victoria and South Australia[3].

Capital versus operating cost bias, cost of capital and risk

An additional aspect of economic regulation incentive that may impact on incentives for DM relates to the attractiveness of operating expenditure relative to capital expenditure. As network infrastructure is primarily capital expenditure and DM program expenditure is usually primarily operating expenditure, a regulatory bias in favour of capital expenditure will also create a bias against DM.

This principle has been identified in the recent Ministerial Council on Energy review:

> The revenue rule approach to WACC determination should avoid creating systematic upward bias in the WACC. Equally it should not create systematic downward bias, either for the purpose of balancing DSR and DG incentives or any other reason.
>
> The range of regulatory measures available to address the potential imbalance of incentives as between capital and operating cost expenditure should include:
>
> - allowing (but not requiring) the AER to include a capital expenditure efficiency incentive mechanism in the building blocks control setting method for individual Distributors; and
> - requiring the AER to consult on the potential DSR and DG incentive implications of any proposed operating or capital expenditure efficiency incentive mechanism (Standing Committee of Officials of the Ministerial Council on Energy 2007, pp. 5–6)

While this is a commendable objective, determining an unbiased Weighted Average Cost of Capital (WACC) has long been a principle of economic regulation of Distributors.

The overall regulatory structure needs to recognise that Distributors are likely to perceive greater risk in adopting new (more sustainable) practices in relation to DM than in the conventional past practices from which the current WACCs have been derived. Allowing Distributors to earn a higher return on investment in DM could, in principle, help to offset this bias. However, as Distributor expenditure on DM is often regarded as operating rather than capital expenditure, in practice such a reform may have little effect.

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[3] Note however, that South Australia has created a specific $20 million fund to support DM as discussed below (see Chapter 5).

Demand Management in Australia

The extensive barriers to the efficient development of DM in Australia have long been acknowledged. For example in 1993, Crossley and Gordon noted

> *Under the pricing regulation system currently applied, sales reductions also reduce utility profit margins. Therefore, most energy saving opportunities are not cost effective from the utility's point of view. This presents the major barrier to utility involvement in customer energy efficiency improvement* (Crossley & Gordon 1993).

There has however been some significant DM activity in Australia. Large-scale DM has been implemented in relation to off peak water heating since at least the 1940s (Wilkenfeld & Spearritt 2004 ch. 3 p. 4). This form of DM currently provides about 600 MW of load management, equivalent to around 10% of Energy Australia's load. Interruptible supply contracts for large industrial consumers such as aluminium smelters probably provide a similar level of DM capacity in NSW. While accurate data on this is not publicly available, it is likely that together, these two forms of DM represent capacity equivalent to between 10% and 20% of Australia's peak electricity demand. However, what links these two success stories of DM in Australia is that they support *additional* electricity sales rather than encouraging energy efficiency. It is the energy saving side of DM that has been lacking in Australia.

Another key element of DM is more efficient time-of-use tariffs, or "tariff-based DM". Such tariffs are crucial in providing incentives to customers to shift load and reduce demand at peak times. However, such tariffs will do little to encourage networks to invest in DM measures that reduce overall energy consumption. In recognition of this, the NSW Independent Pricing and Regulatory Tribunal adopted the D-factor. The fact that this mechanism – which some commentators have characterised as "over-rewarding" demand management – has to date only enjoyed modest success in encouraging DM is testimony to the strong barriers to DM that exist within price cap regulation.

While efficient time-of-use pricing will provide incentives for consumers to reduce peak demand, they will do little if anything to redress the perverse incentives to DM that are created for networks as a consequence of price cap regulation.

Demand Management overseas

While it is beyond the scope of this report to review DM activities overseas in detail, some consideration of DM practice in other countries is useful in order to put the NSW and Australian experience into context. The Federal Government's 2004 landmark energy policy report *Securing Australia's Energy Future* noted that International Energy Agency had found that Australia's energy efficiency has improved at less than half the rate of other developed countries. It also identified DM as a key tool for lifting Australia's energy efficiency performance (Australian Government 2004, p.105-111).

In the United States, total utility DM expenditure on DM in 2006 was over US$2 billion. This is equivalent to US utilities spending an average of over 0.7% of their revenue on DM (Energy Information Administration). By comparison, the total DM expenditure by NSW Distributors in relation to the D-factor in 2004/05 and 2005/06 was $5.1 million (see Chapter 4). This is equivalent to just 0.13% of the Distributors' revenue (IPART 2004, p.73). In other words, as a share of utility revenues, the NSW D-factor is facilitating less than one fifth as much DM expenditure as is funded by the average utility in the US.

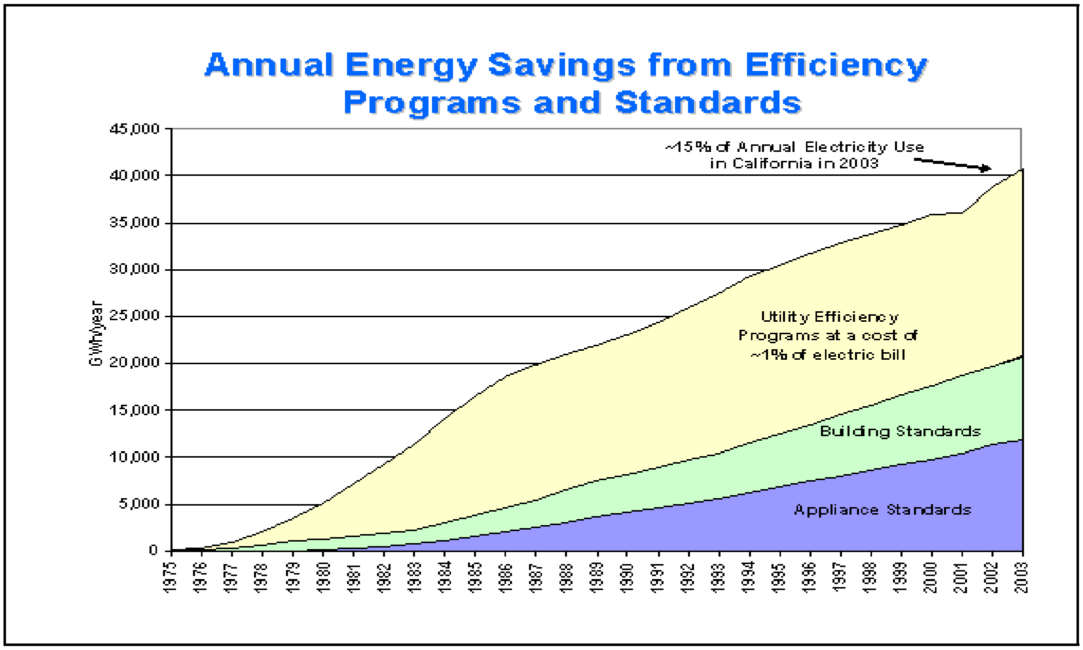
Another way comparing is to consider per capita DM expenditure. In the US in 2004, utility funded energy efficiency DM programs in different states ranged from zero to in excess of $20 per person, with a national average of US$4.93 per person (equivalent to about AU$5.50 per person) (Eldridge, p.7). By comparison, all forms of DM expenditure by NSW Distributors in relation to the D-factor amount to about $2.5 million per annum (see Chapter 4). This is equivalent to about 40 cents per person in NSW. While this figure does not include expenditure on DM by NSW electricity retailers, it gives a further indication of the modest level of DM activity by electricity utilities in NSW compared to those in the US.

Effective regulation for DM in practice: the California example

Given the relatively underdeveloped state of DM in Australia, it can be tempting to assume that even if the significant existing barriers to it were removed, DM would still only play a marginal role in addressing the growth in electricity demand. An often-heard comment is "DM might be a good idea, but it can only ever defer, rather than avoid, electricity supply infrastructure investments". Even if this were true, this assertion obscures the fact that deferral of multi-million dollar investments can be very valuable in their own right. However, the evidence from jurisdictions where DM has been aggressively pursued is that DM does have the potential to both defer *and avoid* major infrastructure investment. In California, where DM has been supported by the Government, economic regulators and utilities to varying degrees for around 30 years, provides an illuminating case study.

DM has made a major contribution to meeting the electricity needs of California. As of 2003, DM was estimated to have reduced overall electricity consumption by around 20,000 GWh per annum or about 7% of total electricity consumption (see Figure 1). This is in addition to a similar level of energy savings achieved through building and appliance energy-efficiency standards.

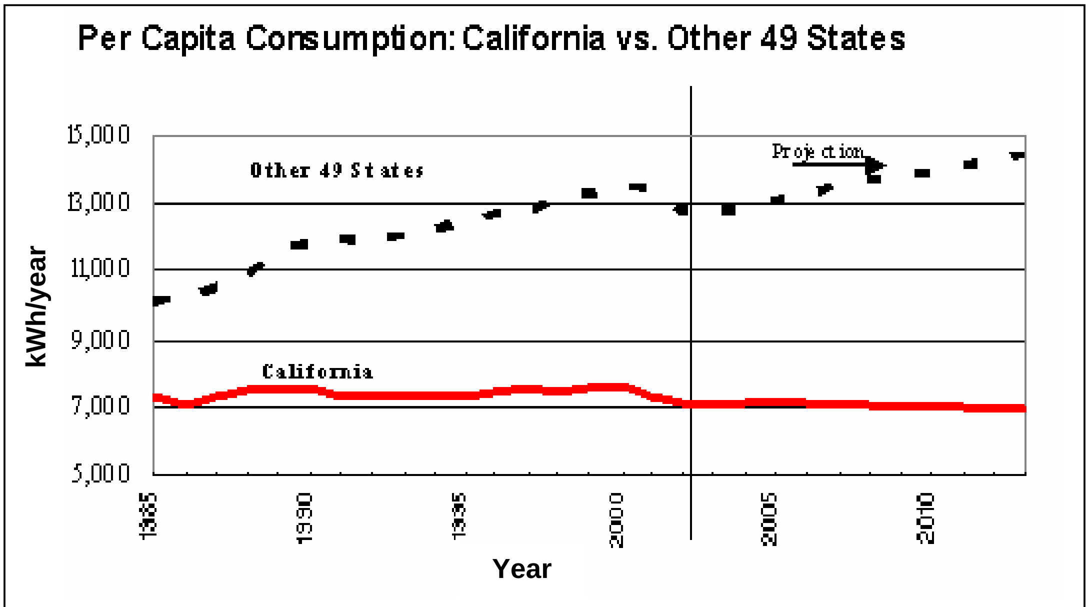
Figure 1



Source: (State of California 2005)

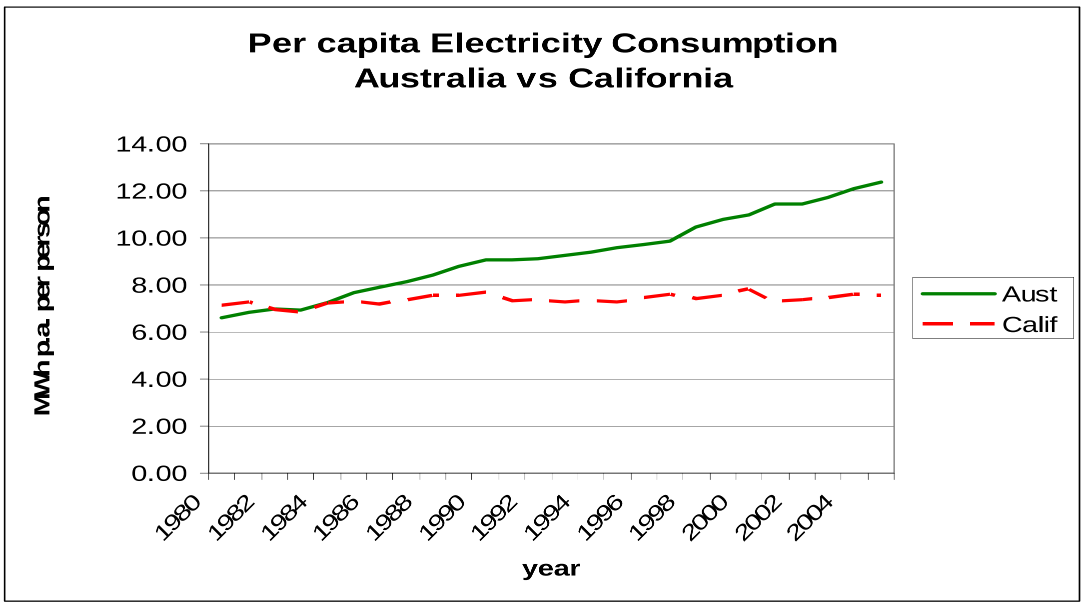
The effectiveness of DM in California is further highlighted by comparing the trends in per capita electricity consumption in California with those in the remaining 49 states of the USA (Figure 2). While electricity consumption in the rest of the USA (including several other states that have strong DM programs) increased by about 30% between 1985 and 2003, Californian electricity consumption remained static at about 7 MWh per person per annum. A comparison of Californian and Australian electricity consumption over the past 25 years provides an even more striking contrast, as illustrated in Figure 3.

Figure 2



Source: State of California 2005

Figure 3

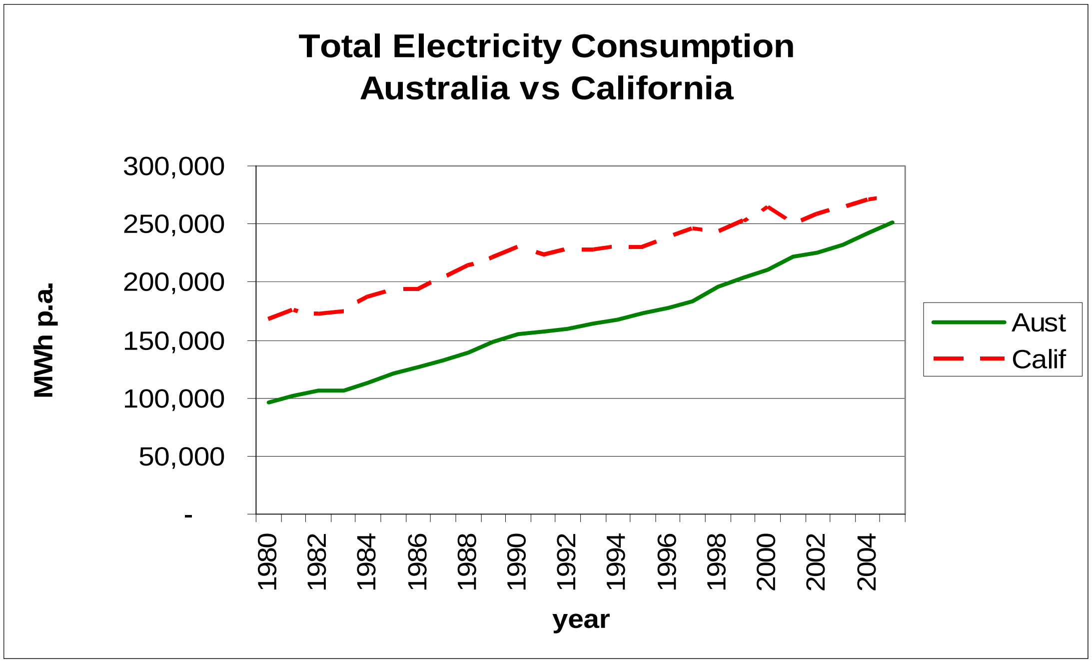


Sources: Australian Bureau of Statistics n.d.; California Energy Commission 2006; Real Estate Center 2006; Australian Bureau of Agricultural and Resource Economics 2006.

While Californian electricity consumption has remained virtually static between 1980 and 2005, Australian per capita electricity consumption has increased by 70%.

The growth in per capita electricity consumption has been so much faster in Australia that, as illustrated in Figure 4, Australia's total electricity consumption is now close to that of California, despite California having almost twice the population and a much larger economy.

Figure 4



Sources: Australian Bureau of Statistics n.d.; California Energy Commission 2006; Real Estate Center 2006; Australian Bureau of Agricultural and Resource Economics 2006.

There are, of course, several reasons for these starkly different trends in energy consumption, including changes in structure of the economy, different resource bases and energy price trends and different policy settings. While electricity utility DM is clearly not the only reason for this remarkable success in promoting energy efficiency, it is equally clear that a regulatory system that removes barriers to and supports DM can, when combined with proactive government policy, have a major impact on energy consumption and infrastructure requirements.

3 NATIONAL REGULATION OF ELECTRICITY DISTRIBUTION NETWORKS

Reform of distribution regulation

In June 2004, the Commonwealth, State and Territory Governments adopted the Australian Energy Market Agreement (AEMA). This Agreement included commitments to establish the Australian Energy Regulator (AER) and the Australian Energy Markets Commission (AEMC). The Agreement also included a commitment to transfer responsibility for economic regulation of distribution networks in jurisdictions participating in the national electricity market from State (and ACT) based regulators to the AER by 31 December 2006 (COAG 2006a).

The first application of the AER responsibilities in regulating distribution network pricing will be in relation to the NSW and ACT determinations which both take effect from 1 July 2009. The processes for making these determinations are already in train and will ramp up significantly over the next few months. This provides an unprecedented opportunity to redress the past shortcomings in regulating networks in relation to DM.

Furthermore, given the widespread sense of urgency in the community about the need to slow climate change, there is a renewed interest in the potential for DM and energy efficiency to provide a low-cost option to reduce greenhouse gas emissions.

State, Territory and Federal Governments have made numerous statements in support of DM. For example, in its February 2006 communiqué, the Council of Australian Governments (COAG) stated:

> COAG has agreed that:
>
> - all jurisdictions are committed to working collaboratively as well as individually to reduce Australia's emissions of greenhouse gases, …making Australia a leader in the global effort to stabilise greenhouse gas levels in the atmosphere; …
> - action on climate change requires a comprehensive policy framework which includes action to ***promote changed patterns of investment***, technology innovation and take up, adaptation, ***demand management and improved energy efficiency***…."
>
> **Energy Efficiency**
> Energy efficiency has a significant role to play in reducing greenhouse gas emissions, and in ***reducing requirements for future investments in energy supply and infrastructure***. Energy users currently spend $50 billion annually on energy. It is widely considered that many businesses and households can save 10–30 per cent of their energy costs without reducing productivity or comfort levels.
> Energy efficiency has consistently proved to be the most cost-effective of Australia's responses to greenhouse gases. …
> Jurisdictions note and support the proposal in the Review of National Competition Policy for COAG to task the MCE to develop a work program from 2006 ***to establish effective demand-side response mechanisms in the electricity market***. (COAG 2006b).

Every Government in Australia – Federal, State and Territory – has stated its desire to encourage investment in demand management, energy efficiency and low greenhouse gas emission technologies. The regulatory decisions of the AER and the National Electricity Rules under which it operates will influence billions of dollars worth of electricity sector investment decisions over the next decade. These investments will be with us for decades. Each time that investment in cost-effective DM is overlooked in favour of traditional centralised high-carbon electricity supply represents not just a lost opportunity, but also a carbon emission liability that will have to be compensated for in the decades to come.

The National Electricity Rules must be consistent with National Electricity Law. Therefore, to consider the appropriateness of the Rules requires reflecting on the appropriateness of the Law.

According to the National Electricity Law, the legislated objective of the National Electricity Market "*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*." This objective was drafted before it became universally accepted that our energy sector faces major changes in order to respond to the challenge of climate change. Building institutions based on the high carbon emission model of the past is no longer environmentally sustainable, economically prudent, or possibly even politically viable.

While at first glance, the above objective appears clear, it is in practice highly ambiguous in relation to DM. In pursuing the above objective, the AEMC and the AER are required to make judgements on the following questions.

1. Does "efficient investment in … electricity services" mean that network businesses should invest in alternatives to network infrastructure, such as distributed generation, demand management and energy efficiency ("DM"), wherever this would lead to lower average energy bills for consumers?
2. Does "efficient investment in … electricity services" mean that network businesses should offer incentives to individual consumers to adopt DM wherever this would lead to lower energy bills for consumers (or improved quality, reliability, and security of supply)?
3. Where a conflict arises between lower average prices and lower average bills (such as in relation to encouraging end-use energy efficiency), should the AER support lower average bills?
4. Does "efficient use of, electricity services" also mean the "efficient use of electricity" by means of DM?
5. Does "the long term interests of consumers" include consideration of the expected long-term costs of the economic impacts of climate change and policy responses in response to climate change?
6. Does "the long term interests of consumers" include consideration of the likely trends in the regulated and market costs associated with greenhouse gas emissions?
7. Does "the long term interests of consumers" include consideration of current and expected future trends in the relative costs of different supply options, including DM?
8. Does "the long term interests of consumers" include investigation and consideration of consumers' preferences as to their long-term interests, particularly regarding supply options, DM and social equity?

While it might seem reasonable to answer "yes" to each of these questions, it is also plausible to argue the opposite. These are high-level policy principles, not fine details of regulatory interpretation. Stakeholders (and the AER) may legitimately expect such policy principles to be defined by Government policy. They should not be left to the judgement and interpretation of the AER.

If the Government policy statements above regarding the desirability of DM are as deliberate and consistent as they appear, then there seems no reason why they should not be reflected in the National Electricity Law by removing these ambiguities.

The National Electricity Rules to be applied by the AER in relation to distribution, revenue and pricing continue the bias in favour of centralised supply systems and against DM options that has characterised the NEM since its establishment. This bias against DM contravenes the competitive neutrality and economic efficiency principles of the NEM.

A truly “level playing field” would require full recognition of the ***economic*** costs of increasing greenhouse gas emissions. However, the national electricity market (NEM) now excludes these economic costs. Moreover, the NEM fails to provide a “level playing field”, and even ignores these economic costs. This lack of competitive neutrality and economic efficiency would represent a significant failure even if the science of climate change is ignored. However, in 2007 in the wake of the Stern Report (Stern 2006), the IPCC Working Group III Report (IPCC Working Group III 2007) and the 2006 IEA Energy Technology Perspectives Report (IEA 2006), it would be irresponsible in the extreme for energy and economic policy makers and regulators to ignore the expected economic impacts of unabated climate change.

Appendix 1 includes recommended amendments to National Electricity Rules to facilitate a clearer and more even-handed policy framework for DM.

4 THE PERFORMANCE OF THE NSW D-FACTOR

4.1 Introduction

This chapter reviews the impact of the D-factor in supporting DM in NSW in 2004/05 and 2005/06, the first two years in which the D-factor applied and the only years for which data on the impact of the D-factor was available.

The three NSW Distributors, Energy Australia, Integral Energy and Country Energy, have been differently influenced by the D-factor as an incentive, due to their different approaches to DM. Consequently they have taken advantage of the D-factor measure to differing degrees.

Energy Australia has invested the most in response to the D-factor, mainly in "facilitated projects", where the Distributor installs discrete technologies such as power factor correction (PFC) equipment or on-site generation which can be directly controlled by the Distributor. These programs have been effective in achieving relatively large load reductions at relatively high cost. It appears that the D-factor has been a significant driver for these initiatives.

In contrast, Integral Energy has invested more heavily in "market approaches" where DM service providers bid to undertake DM activities in areas of network constraint, and the selected service provider is compensated by the Distributor on a $-per-kVA of reduced peak demand basis. The DM initiatives that Integral Energy has invested in have reportedly achieved smaller load reductions compared to Energy Australia, but at relatively lower cost. Integral Energy have continued to expand their DM activity after 2005/06, and as of December 2007, Integral Energy was reported to be implementing its twelfth DM program (Bucca, 2007). This expansion in DM activity has coincided with the creation of the D-factor, which appears to have been a significant stimulus for this expansion.

Country Energy has only a small amount of DM investment of either sort. The only program of significance, the Binda Bigga project, was planned before the introduction of the D-factor. Thus it is likely that the D-factor has not made any material difference to Country Energy's decision-making processes for DM up to 2005/06.

Note that this assessment does not include price-based or "tariff-based" DM, except where the cost of this has been claimed under the D-factor. The NSW Distributors and Energy Australia in particular, have made major investments in replacing traditional accumulation electricity meters with time-of-use meters. These time-of-use meters can support time-of-use electricity prices to encourage consumers to shift their power consumption from times of peak demand to off peak. All three NSW Distributors are now supporting time-of-use pricing in some form. While such tariff-based DM is crucial for reducing the need to build new, rarely used supply infrastructure, it generally shifts demand rather than reducing overall energy use, and does not involve offering direct incentives to consumers to reduce demand. It therefore does not face the same barriers as active DM and therefore is not a key focus of the NSW D-factor.

4.2 Information sources and limitations

In order to assess the quantitative impact of the D-factor in NSW, we have relied upon:

(a) Publicly available information included in Distributors' Annual Network Management Reports published in compliance with their licence conditions[4]

(b) D-factor submissions (2004/05 and 2005/06) by Energy Australia and Integral Energy, provided in confidence

(c) Personal communications with representatives of Energy Australia, Integral Energy and Country Energy

(d) The Binda Bigga Demand Management Project report in lieu of D-factor submissions from Country Energy (NSW Department of Energy Utilities and Sustainability 2005)

(e) Aggregated information provided by IPART (IPART 2007).

Source (a) has been the only source of data consistently available before and after the introduction of the D-factor[5]. However, as representatives from the Distributors pointed out, these sources report *expected* lifetime costs and impacts of each *prospective* project, rather than DM actually implemented. This increases the likelihood of inaccuracy, particularly when projects run over several years as they frequently do. This also leads to often significant discrepancies with similar data from source (b), presented below. Furthermore, the reporting formats in source (a) have varied by year and sometimes by DM-type, making meaningful quantitative comparisons difficult. In the absence of any other reference data, source (a) is used here to compare data immediately before and after the introduction of the D-factor in 2004/05.

Source (b) provides data relating to ongoing rather than prospective DM activity, and is reported in a uniform way. However, as discussed below, the nature of DM activities undertaken mean that comparisons between Distributors are problematic. Related to this, the calculations included in the reports and supporting documentation from Energy Australia and Integral Energy do not allow additional information to be extracted in a uniform way (for example, disaggregating 'additional' outcomes from outcomes that run over more than one year). Finally, two years of data do not allow longer-term trends due to the introduction of D-factor, if they exist, to become apparent. These limitations are discussed in the relevant sections below.

Appendix 3 provides a summary of the DM projects, proposals and investigations reported by the Distributors between 2000/01 and 2005/06 through their Annual Network Management Reports. While this information provides interesting background to the level of network DM activity in NSW, it is an unreliable data source as it is incomplete, inconsistent and includes both actual and proposed DM projects.

4.3 Estimating D-factor outcomes

(a) Estimated *additional* peak load reductions through DM

Table 1 below shows additional peak load reductions achieved through DM, according to the different sources.

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[4] Network investments for power factor corrections using network capacitors, although reported in source (a), have been omitted in the analysis here, as these are not eligible DM activities under the D-factor.

[5] Data from source (a) is provided in Appendix 3.

Table 1: Additional peak load reductions from DM (MVA)

(Note: D-factor introduced in 2004/05)

	2003/04	2004/05	2005/06	Source
Energy Australia		**20.5** *	**1.6 ***	(1)
	15	9.6	12.7 #	(2)
Integral Energy		**8.9**	**10.6**	(1)
	9.8	41.3	6	(2)
Country Energy			**0.2**	(3)
	0.1	1.6	6.4	(2)
Total	**-**	**29.4**	**12.4**	(1)

(1) From Distributors D-factor submissions to IPART (source (b))

(2) From Annual Network Management Reports (source (a)). These data are considered less reliable.

(3) From Binda Bigga Project Report

* Excludes peak load reduction due to 26.8 MVAr of reactive support in 2004/05 and 16.1 MVAr in 2005/06.

Includes 11.3 MVA of Distributed Generation.

It is estimated that *new* DM measures *implemented* by the three NSW Distributors following the creation of the D-factor delivered a reduction in peak demand in NSW of 29.4 MVA in 2004/05 and a further 12.4 MVA in 2005/06. This is equivalent to about 6.6% and 3% respectively of the average annual growth in summer peak demand in NSW (Transgrid 2007, p. 1). These results suggest that the anticipated introduction of the D-factor in 2004/05 led to a jump in planning for new load reduction measures using DM, although there was some prior DM activity.

The peak load reduction achieved by Energy Australia in the first year of the D-factor is significantly higher than in the previous year, with the second year bringing smaller additional reductions. This result may be inferred to be the consequence of the types of DM undertaken. A majority of EA's current DM projects involve discrete 'engineering' solutions, and when the technology is installed, the full reductions from the program can be reported. For example, in 2004/05, Energy Australia reported

- five programs utilising power factor correction (PFC) on customer sites,
- five programs with onsite generation controlled and dispatched by Energy Australia,
- one system-wide energy efficiency project using compact fluorescent lamps, and
- one standard offer (taking a market approach) in its D-factor submission.

In contrast, Integral Energy's load reductions increase incrementally over the two years, since their DM programs mainly involve offers to third parties to deliver DM, which lead to incremental additional load reductions over several years. For example, in 2004/05, Integral Energy reported market approaches for five programs, and one program where a large load shift was negotiated with a major customer. The load reductions are achieved more gradually over the contract period. Integral Energy's source (a) data nevertheless suggests a jump in expected load reductions, suggesting a large increase in planning for new investment in DM. This is also supported by the increase in the additional load reductions achieved as each of their programs ramp up. Moreover, the above data understates the increase in activity due to the D-factor as the two major DM programs undertaken in 2003/04, Castle Hill and Blacktown, where both initiated in anticipation of the establishment of the D-factor or similar mechanism which had already been foreshadowed by IPART (Bucca, 2007).

For Country Energy, information from D-factor submissions was unavailable. Their source (a) data suggests that Country Energy may be considering increasing future DM investments. However, there is no available firm evidence that the D-factor has influenced Country Energy's level of DM activity.

(b) Value of network savings from DM activities

The value of network savings from deferral of network augmentation costs as a result of DM activities is approximated by the *Avoided Distribution Cost Cap (ADC)* reported in D-factor submissions (representing the maximum amount of program costs that are allowed to be claimed). However, reported ADC from year to year does not necessarily represent *new savings* from deferrals. For example, if a particular DM program had program costs below the ADC in 2004/05, the remaining or 'residual' ADC (adjusted to 2005/06 dollars) is permitted to be carried over and used as the program's ADC for 2005/06.

(The ADC is based on the net present value calculations of the differences in CAPEX and OPEX with and without the DM investment associated with each program. A small discrepancy arises between Distributors' calculations of ADC. Energy Australia approximate OPEX as *OPEX = 2%* x *CAPEX*, so their NPV calculations involve a *constant* annual OPEX cost over the period. Integral Energy, on the other hand, uses the approximation *OPEX = 2%* x *depreciated CAPEX*, so they have a *decreasing* OPEX over the period of their NPV calculation. While the consequences of such a discrepancy may be small, it highlights that having clearly prescribed calculation methodologies can lead to more comparable data from the different Distributors.)

The differences in the nature of DM measures undertaken by Distributors, and the resulting differences in how their calculations of ADC are reported, means that it has not been possible uniformly to disaggregate *new network savings* from *residual* savings (carried over from the previous year's ADC). As noted earlier, a majority of Energy Australia's current DM programs achieve immediate load reductions and corresponding network savings upon implementation (installation of discrete 'engineering' technology devices). Related to this, Energy Australia's reporting format allowed us to identify that of its 2005/06 ADC, $2,364,500 represented *new* network savings and $3,681,128 was 'residual' from programs commenced in 2004/05. In contrast, Integral Energy's DM involve incremental energy efficiency measures taken up over several years, and its reporting of ADC calculations meant that it is difficult to disaggregate 'new' savings from 'residual' network savings from the previous year.

Table 2 summarises the estimated value of savings from DM measures immediately before and since the introduction of the D-factor.

Table 2: Value of savings from DM ($)
(Note: D-factor introduced in 2004/05)

	2003/04	2004/05	2005/06	Source
Energy Australia		**$5,578,517**	**$2,100,000 ***	(1)
	$ 2,460,650	$7,713,854 #	$ 2,092,000	(2)
Integral Energy		**$ 4,411,000**	**$7,190,000**	(1)
	$1,003,000	$ 6,301,000	$1,104,000	(2)
Country Energy			$ 304,500	(3)
	$ 108,100	$ 835,000	$4,650,000	(2)
Total	**-**	**$9,989,517**	**$13,235,628**	(1)

(1) From Distributors D-factor submissions to IPART (source (b))

(2) From Annual Network Management Reports (source (a)). These data are considered less reliable.

(3) From Binda Bigga Project Report

* Excludes $3.9 million of "unrecovered" ADC carried forward from 2004/05 in 2005/06 D-factor submission.

Includes $4.3 million worth of network capacitor investment that is not DM but is required to be reported .

(c) Cost effectiveness of DM measures

The above data suggests that the introduction of the D-factor has been accompanied by a modest increase in implementation of DM by two of the three NSW Distributors, Energy Australia and Integral Energy. However, a key issue for considering the effectiveness of the D-factor is whether the DM investments were worthwhile – did the benefits of the DM initiatives exceed the costs? To address this question, we consider the net benefit in avoided network costs (**Avoided Distribution Cost** – ADC) as compared to the **Actual Program Cost** of the DM reported by Energy Australia and Integral Energy under the D-factor. This information is shown in Table 3 below. The following data have been independently audited before being submitted to IPART for consideration. Also shown in Table 3 are:

- **Eligible Programs Costs:** this is equal to the actual program costs, unless the actual program costs exceed the ADC
- **D-factor Claim:** this is the amount claimed by the Distributors and includes program costs (up to the ADC), foregone revenues due to reduced energy sales and compliance costs (costs of independent audit of submissions).

(Note that the foregone revenue that is also recovered through the D-factor is not included in this benefit cost analysis as it is simply a transfer payment to protect Distributors from a "windfall loss" of income, and is therefore not a real economic cost.)

Table 3: Benefits and costs of DM under the D-factor ($)

Energy Australia	**Avoided Distribution Cost (B)**	**Actual program costs (C)**	Eligible program costs	D-factor claim[6]	**Benefit/cost ratio (B/C)**
2004/05	$5,578,517	$2,163,166	$2,127,991	$3,592,044	**2.6**
2005/06	$2,100,000 *	$2,368,678	$1,597,850	$3,348,660	**0.9 ***
Total	$7,678,517	$4,531,844	$3,725,841	$6,940,704	**1.7**
Integral Energy	**Avoided Distribution Cost (B)**	**Actual program costs (C)**	Eligible program costs	D-factor claim[7]	**Benefit/cost ratio (B/C)**
2004/05	$4,411,000	$234,144	$234,144	$460,492	**18.8**
2005/06	$7,190,000	$303,897	$303,897	$709,228	**23.7**
Total	$11,601,000	$538,041	$538,041	$1,169720	**21.6**
Total	**$19,279,517**	**$5,069,885**	$4,263,882	$8,110,424	**3.8**

* Excludes $3.9 million of "unrecovered" ADC carried forward from 2004/05 in 2005/06 D-factor submission.

The disparity between the Energy Australia and Integral Energy benefit/cost ratios and the extraordinarily high benefit/cost ratios for Integral Energy's DM projects merit further examination. Integral Energy reports much lower program costs relative to the avoided distribution costs. On examining Integral Energy's D-factor submission the following factors are suggested to account for the discrepancy:

1. As the ADC is prospective, it may exaggerate the actual extent of investment deferral achieved in practice;
2. As the actual program costs are annual costs, they may exclude future costs that may be incurred in order to achieve the anticipated investment deferral and the associated prospective ADC;
3. The Program cost estimates appear to exclude some overhead costs associated with developing and administering the DM projects, which Integral Energy could legitimately recover through the D-factor.

Only time will tell how important the first two factors in accounting for the cost-effectiveness discrepancy. If Integral Energy is able to achieve its forecast level of investment deferral, then on the basis of the available evidence its approach of contracting out for DM appears to provide a significantly more cost effective approach to delivering DM projects.

So while the above data should be regarded with some caution, the real cost effectiveness of current DM probably lies somewhere between the Energy Australia average benefit/cost ratio of 1.7 and Integral Energy's 21.6 and perhaps close to the weighted average ratio of 3.8 to 1. This is broadly consistent with the benefits and costs report by IPART (see, IPART 2007, table 2). In any case, the benefits (avoided distribution costs) exceed the program costs by a significant margin. Given the relatively undeveloped state of the DM services market in NSW, these a very

[6] The claimed amount in year t is the sum of DM program costs (up to the ADC), foregone revenues and compliance costs (costs of independent audit of submissions) in year (t-1), expressed in year (t+1) dollars.

encouraging results, They suggest that there are much more extensive cost effective DM opportunities available with very attractive benefit cost ratios. Furthermore, it is reasonable to expect that the cost of DM services will fall as the market develops, and this should lead to even greater scope for cost-effective DM.

Given the high benefit cost ratios implied in the reported data, it could be tempting to conclude that the D-factor was unnecessary to stimulate these DM measures. However, closer inspection does not support such a conclusion. Firstly, these figures indicate that some of the DM options undertaken by Energy Australia have been of relatively high cost, as reflected in the total actual program costs exceeding the total eligible ADC. In these cases, the D-factor would likely provide a significant incentive for investment.

Secondly, while Energy Australia funded one of its DM programs entirely through NSW Greenhouse Gas Abatement Certificates, it has been able to recover almost a million dollars in foregone revenues through the D-factor. It is likely that without the D-factor, the internal business case for this DM program would have been much weaker. For Integral Energy, on the other hand, the program costs and foregone revenues have been very low in comparison to the forecast benefit of network deferral. In this case, the D-factor may not have made a material difference to the economics of the business case, but may still have had a material impact on the perception of risk and the willingness of the Distributor to invest in DM.

Consistent with the above discussion, interviews with Energy Australia and Integral Energy staff reflected indicated that the D-factor provided greater confidence to their organisations' senior management to make decisions to invest in DM, particularly in relation to being able to recover operating costs of DM programs. All Distributor representatives indicated that the D-factor should not be retained or if removed it should be replaced with another DM-supporting measure that was at least as effective.

Perhaps the most compelling evidence for the value of the D-factor is the cost effectiveness that has been reported for DM that has been initiated in response to the D-factor's introduction. As noted in section (c) above there appears to have been a significant increase in DM implementation in NSW associated with the commencement of the D-factor. Given the likelihood that these highly cost-effective DM projects would not have been undertaken in the absence of the D-factor, this strongly suggests that cost effectiveness alone does not lead to implementation of DM.

(d) Greenhouse emission and energy savings of DM initiatives claimed under D-factor

While DM initiatives have reduced the electrical energy consumed (MWh) and brought about corresponding greenhouse emission reductions and savings on consumers' energy bills, this data is not included in the D-factor reports to IPART. However, the Network Management Reports do include estimates of expected greenhouse gas emission abatement and these have been included in Table 4. As discussed above, these figures do not necessarily correspond to the figures reported in the Distributors' D-factor submissions. For comparison, the value of sales foregone claimed in these submissions is also included in Table 4.

As noted in Table 4, the total greenhouse gas emission reduction is estimated at about 500,000 tonnes of carbon dioxide over a ten year period. Not withstanding the uncertainty regarding the accuracy of these estimates, it seems safe to conclude that the DM measures implemented under the D-factor framework have contributed a modest but not insignificant reduction in emissions.

Table 4: Indicative emission and energy savings under the D-factor

Energy Australia	Estimated Greenhouse Gas Emission Abatement [2] (t CO_2 over 10 year life)	Foregone Revenue claimed [1]
2004/05	5,440 *	$856,866
2005/06	48,430 *	$1,176,692
Integral Energy		
2004/05	270,000	$154,594
2005/06	146,880	$287,295
Country Energy		
2004/05	34,800	nil
2005/06	4,500	nil
Total	**510,050**	**$2,475,447**

[1] Source: Distributors D-factor submissions to IPART.

[2] Source: From Annual Network Management Reports.

* Excludes 200,000 tonnes in 2004/05 and 500,000 tonnes in 2005/06 of CO_2 abatement due to compact fluorescent lamp give-away across the Energy Australia network area. This program was primarily funded through the Greenhouse Gas Abatement Scheme.

It should be emphasised that the above are indicative figures only. It is strongly recommended that future reporting of the outcomes of DM measures includes both the amount of energy savings and the associated greenhouse gas emissions avoided.

5 COMPARISON WITH DM PERFORMANCE IN OTHER STATES

Victoria

Network tariffs are subjected to a regulated price cap imposed by the Essential Services Commission Victoria (ESCV). The ESCV recently introduced a modest provision for DM initiatives of $600,000 for each Distributor[7] in their operating costs to be included within the methodology of calculating the price cap as an encouragement for DM investment.

Our assessment of DM undertaken in Victoria is made on the basis of phone conversations with representatives from each of the five Victorian Distributors United Energy, Powercor, CitiPower[8], SPAusNet and Alinta AE (formerly AGL Electricity), and their annual *Distribution System Planning Reports* (for 2006) available on their websites. All five networks are owned and operated by the private sector.

All five Distributors reported that they make very little DM investment and had no active programs in place. Reasons most repeated were:

- While network constraints are published to encourage proposals for non-network solutions, there has been little interest. A handful of expressions of interest to aggregate customer DM has gone no further than conversations.
- There is no incentive for networks to undertake DM. Any programs need to be funded internally.

Interestingly, the $600,000 provision for recovering DM-related operation costs was not raised by any of the representatives who operated mainly at an implementation level. Our inquiry addressed to one Distributor was referred to a representative that dealt with regulatory matters. This would suggest that the provision is not known and taken advantage of at the implementation level.

The only DM initiatives of significance identified were Powercor's hot water load management (reducing hot water peak load by 40–50 MVA) and Alinta AE's agreement for network support from a 150MW embedded market generator. Representatives of United Energy, CitiPower and SPAusNet agreed it would be fair to describe their DM activity as near-zero.

DM described in Distributors' annual *Distribution System Planning Reports* (2006) is limited to statements of commitment to consider non-network solutions to network constraints published in the reports.

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[7] See http://www.esc.vic.gov.au/NR/rdonlyres/C9D582D3-3C20-4CFD-9B9D-687D0063472A/0/EDPRDeterminationVol1Amendedinaccordancewithappealpaneldecision.pdf

[8] Powercor and Citipower were in the process of merging operations into a single Distributor at the time of our interviews, and now operate as a single entity.

South Australia

The sole monopoly Distributor operating in South Australia, ETSA Utilities, is regulated by the Essential Services Commission of South Australia (ESCOSA). ETSA Utilities is privately owned[9].

As in Victoria, the South Australian distributor is subject to a Weighted Average Price Cap, which strongly couples revenue and profitability to electricity sales volume.

Our assessment of DM undertaken in South Australia is made on the basis of the publicly available annual *Network Management Plan 2006/07 – 2010/11* (2006) and *Annual Demand Management Compliance Report* (2006) submitted by the single South Australian Distributor ETSA Utilities, and phone conversations with two representative from ETSA.

In 2005, a $20.4 million budget was delegated by ESCOSA for ETSA Utilities to undertake a research and development program aimed at introducing demand management strategies within South Australia from 2010. ETSA Utilities has a vision to become the national leader in DM. Up to December 2006, ETSA had spent $1.88 million on DM.

In addition to their R&D program, ETSA states that it undertakes regular DM as part of good asset management. A range of policies and procedures with large customers incentivise load shifting and load limiting devices. No quantitative data in terms of how much load is reduced, or what the benefits from deferral of network incentives from DM is currently available since “no-one asked for it” until very recently. A draft report with quantified DM information is currently being reviewed, and is likely to become available in the next few months.

[9] ETSA is owned by the same consortium that owns Powercor and CitiPower in Victoria.

6 LESSONS FROM THE NSW D-FACTOR

Benefits of the D-factor

Compared to past NSW practice and current interstate practice, the available evidence indicates that there has been greater consideration and implementation of DM by Distributors in NSW since the D-factor was instituted. Discussions with the responsible officers in the NSW Distributors indicate that the D-factor has been a significant factor in motivating this increased attention to DM. It therefore appears that the D-factor has been successful in stimulating some greater DM activity in NSW. On the other hand, the overall increase in DM activity in NSW in the context of the D-factor has been modest. Furthermore, one of the three NSW Distributors has only initiated and claimed one small project under the D-factor. The evidence clearly indicates that even in a *relatively* supportive regulatory environment, the NSW D-factor has not driven a rapid uptake of DM.

So while it appears clear that the D-factor has been effective in stimulating some DM activity, it appears equally clear that the D-factor, at least in the manner it has been applied in NSW, is not sufficient to deliver an efficient level of DM. In short, the D-factor is an important precedent that should be built upon, but the D-factor alone is unlikely to be sufficient to deliver an efficient level of DM. This raises the question of what are the shortcomings of the D-factor in NSW and how might it be applied more effectively in the context of national economic regulation of Distributors.

Deficiencies of the D-factor

The following reasons have been raised by stakeholders to explain the relatively slow response to the D-factor in NSW.

1. **Time lag in recovery of D-factor**

The D-factor currently requires the Distributor to undertake DM in one year, report the program costs, outcomes and electricity sales foregone during the following year and then subject to IPART approval, recover the program costs and value of electricity sales foregone from customers (via the D-factor) in the third year. This time lag has slowed the learning cycle and therefore the rate of uptake of DM

2. **Perceived riskiness of cost recovery of DM costs by Distributors.**

Some DM staff within the Distributors have reported that it is often difficult to convince senior management to invest money and resources in DM due to the perceived uncertainty of whether the associated costs will be recovered. The two-year lag and the possibility of IPART denying DM costs recovery has been reported to have heightened the perception of risk. Anticipating this perception of risk, in the lead-up to establishment of the D-factor, Energy Australia advocated a "learn by doing" approach, whereby the Distributors could undertake DM expenditure up to a given level without the risk of having recovery of this expenditure rejected by the regulator. The Regulator, IPART, rejected this proposal on the basis that it could lead to ineffective or inefficient DM expenditure.

3. **Lost opportunities due to exclusive focus on short term network constraints**

The current D-factor in NSW only permits the network businesses to recover the costs of DM initiatives where they can be shown to be cost effective in network capacity constrained areas. This focus on network areas approaching their supply capacity is appropriate in relation to short term DM measures that can be established quickly such as curtailable load contracts and some standby and relocatable generators. However, this short term focus results in large lost opportunities relating to DM measures that deliver longer term load reductions well in advance of a network constraint emerging. These lost opportunities particularly relate to energy efficiency and peak load reduction improvements that could be made when buildings are designed and built and equipment appliances are bought and installed. While the additional cost of adopting less energy hungry options at the outset is often small, the cost of improving energy performance at a later date is often prohibitive.

There is a strong case to extend the D-factor to allow Distributors to recover costs associated with "long term DM" in relation to DM opportunities that would otherwise be lost if they are delayed until a local network capacity constraint emerges.

4. Uncertainty over long-term regulatory commitment

The two-year time lag in cost recovery under the D-factor means that costs and electricity sales foregone associated with DM measures in the final two years of the five-year determination can only be recovered in the subsequent regulatory period. This raised Distributor concerns that, with the transition from NSW (IPART) to national (AER) regulation, DM undertaken in the final two years of the regulatory period may be disallowed in the following regulatory period. The recent announcement by the AER that it would apply the same approach to cost recovery in the first two years of the 2009–2014 determination has provided greater confidence for Distributors, but to some extent the damage to confidence had already been done.

5. Competing management priorities

Distributors are currently engaged in the biggest boom in capital expenditure in their history, with annual investment doubling to well over $1 billion per annum in NSW alone. The demands on management in dealing with this expansion have limited their capacity to simultaneously expand their DM activity. The irony of this situation is that there has never been a better time to invest in DM.

6. Absence of a well-developed market in DM

Reflecting the modest investment in DM in NSW to date, there are relatively few service providers in the NSW market that have the skills and experience to rapidly respond to opportunities in DM when they do arise. A number of Distribution staff have observed that the lack of a vibrant competition between DM service providers has hampered their capacity to contract for delivery of DM measures.

While the relative importance of each of the above deficiencies is hard to determine, collectively they represent a significant set of issues to be addressed. In any case, it appears clear that an efficient regulatory structure for DM requires more than just a "D-factor" type mechanism. And an efficient uptake of DM is likely to require more than just an efficient regulatory structure. Options for addressing these deficiencies are discussed in Chapter 7.

7 INTEGRATING DM INCENTIVES IN NATIONAL DISTRIBUTION REGULATION

This chapter draws on the analysis of the preceding chapters to offer recommendations on how a D-factor and/or alternative mechanisms could be deployed to better support DM in the context of national economic regulation of Distributors.

7.1 Clarifying government policy regarding demand management

The establishment of independent regulatory authorities in Australia was intended to make the process of price regulation more efficient, consistent and predictable and less amenable to arbitrary judgements of the regulators. However, this can only be achieved where the rules for regulation are clear. An efficient, consistent and predictable outcome for DM will only be achieved if the rules and expectations are clear. In short, good regulation requires good rules. And good rules need clear policy. Unfortunately, State and Federal Governments have yet to make clear policy in relation to DM, as discussed in Chapter 3.

Stakeholders (and the AER) may legitimately expect that high-level policy intent and objectives in relation to DM should be clearly defined by Government. It should not be left to the judgement and interpretation of the AER.

The absence of clearly articulated DM policy objectives also creates others barriers. For example, Distributors have reported that when they seek to promote DM they frequently faced scepticism from both customers and media that DM is masking a "failure to invest" in network capacity. This prejudice will likely only be overcome by forthright policy leadership by government, coupled with an effective education campaign to emphasise that electricity, like water, is a precious resource to be use wisely and not wasted.

Recommendation 1: Clarify government policy regarding efficient Demand Management.

In recognition of the potential of demand management (DM) both to advance the long-term interests of consumers and to enhance environmental sustainability, State, Territory and Federal Governments should ensure that the National Electricity Law and the National Electricity Rules:

- **explicitly require the Australian Energy Regulator (AER) to make efficient regulatory determinations in relation to DM**
- **explicitly require Distributors to undertake all cost-effective DM prior to network augmentation.**

7.2 Aligning network incentives with consumer and public interest

As noted in Chapter 2, the manner in which Distributors are regulated strongly influences their behaviour and the attractiveness of DM solutions. In particular, price cap regulation strongly "couples" the Distributor's revenue and profitability to the volume of electricity carried through its network and therefore discourages energy efficiency and distributed generation.

The principle of decoupling is now a widely-recognised tool for addressing the disincentives for DM created by price regulation. In the context of distribution networks with high fixed costs and low variable costs, it should be clear that applying price cap regulation that links total revenue directly to sales volume will inevitably create disincentives to DM measures that reduce those sales. This is true whether the sales volumes are measured in simple "anytime" kWh with accumulation meters or with variable time-of-use tariffs.

So long as the marginal revenue (i.e. price under a price cap) is higher than the marginal cost, then networks will be discouraged from undertaking any DM that reduces sales volumes. This is why electricity regulators around the world have created mechanisms to decouple electricity sales volume from network revenue (and profits).

Price cap regulation sets the financial interests of the networks in conflict with the interests of its consumers and the community. However, price cap regulation can be just as bad for the financial interests of Distributors as for the consumers and the environment. Price cap regulation locks Distributor profitability into an old-fashioned business model based on increased consumption, just as Governments are realising that energy efficiency is likely to be the cheapest, largest and quickest option for reducing greenhouse gas emissions. The proposed banning of incandescent lights bulbs is a simple example of how Governments are beginning to take energy efficiency more seriously.

In short, price cap regulation and coupling Distributor revenue to sales volume creates a major financial risk for the networks if consumption volume growth is significantly curtailed due to future government policy to encourage energy efficiency.

Recommendation 2: Align network incentives with consumer and public interest.

In making regulatory determinations, the AER should avoid creating incentives that set the financial interests of the Distributors in conflict with the interests of their customers. In particular, incentives against DM should be avoided in relation to:

- **Short-term incentives (within regulatory periods) associated with price/revenue control formulae; (see Recommendations 3 to 8)**
- **Long-term incentives (between regulatory periods) associated with prudence review and the incorporation of capital expenditure into the capital base and mechanisms for sharing efficiency benefits between shareholders and consumers (see Recommendations 9 to 11); and**
- **Network system development and planning requirements (see Recommendations 12 and 13).**

Recommendation 3: "Decouple" Distributor profit from electricity sales

In setting its year-to-year price control formula the AER should, as a key priority, decouple Distributor revenue and profit from electricity sales volume. That is, the AER should ensure that the profitability of the Distributor is not linked to the amount of electricity carried through its network and consumed by its customers.

As noted in Chapter 2, there is a range of mechanisms available to decouple Distributor profit from electricity sales. The two key options are:

- set a revenue cap to ensure that the Distributor's revenue's is not reduced by any reduction in energy consumption as a result of DM; or
- set a price cap with lost sales adjustment mechanism, such as the D-factor, to allow the Distributor to recover any reduction in revenue resulting from reduction in sales volume due to DM.

The advantages of the price cap/D-factor approach are firstly, that consumers only compensate the Distributor for sales reductions that are deemed by the regulator as genuinely related to the Distributor's DM initiatives, and secondly, that the Distributor's revenue will automatically increase if actual sales exceed forecast sales (for example, if the economy grows faster than forecast).

However, both of these apparent advantages also have countervailing disadvantages. Firstly, making the recovery of DM-related lost sales dependent on approval by the Regulator creates additional costs, risks and delays for Distributors which may discourage them from undertaking DM. While a robust Measurement and Verification (M&V) process may seem attractive in order to avoid the recovery of false "sales foregone" from ineffective DM, there are inevitable challenges in accurately differentiating between "good" and "bad" DM initiatives. Under a revenue cap, the regulator does not need to approve each DM measure, since the revenue is already set and the Distributor's most profitable option is to choose whichever mix of DM and network measures minimises costs.

Secondly, the "automatic adjustment" of revenue due to sales forecast error under a price cap simply replaces one type of volume forecasting risk ("too little" net revenue if sales exceed forecast under a revenue cap) with another ("too little" net revenue if sales fall short of forecast under a price cap), as explained above.

Recommendation 4: Use Revenue caps to decouple network profit from electricity sales.

> **In order to decouple electricity consumption and Distributor revenue and profitability, the AER should apply a revenue cap form of price control in preference to price cap in regulating Distributors.**

Distributors' costs are mainly driven by the amount of network capacity required to meet peak demand, rather than by the volume of energy delivered to consumers. If actual energy consumption diverges from forecast energy consumption, this will have little impact on Distributor total costs and therefore will not create a significant need for additional revenue. However, if peak demand grows faster than forecast, and networks invest (in either network capacity or DM) then this can significantly increase Distributors' costs and reduce their profitability.

While this risk of a net revenue shortfall if peak demand exceeds forecast has been used to argue against revenue caps, it is possible to moderate Distributors' exposure to this risk within a revenue cap. The key drivers for peak demand exceeding forecast demand are: variations in weather and variations in the level of economic activity. By linking or "recoupling" the regulated revenue cap to the drivers for peak demand, the Distributors can be largely insulated from the main peak demand forecast error, without the perverse incentives created by a price cap.

In practice, as the variations in weather that drive peak demand are unpredictable and tend to balance out over time, there is less reason to link the revenue cap to this driver of peak demand. Most states in the US are now using numbers of customers as the "growth" factor – i.e. a revenue per customer method. This approach was also applied by IPART in NSW with its "hybrid revenue cap" between 1995 and 1999. However, while population and customer numbers are linked to peak demand, this relationship is not as direct as the relationship between economic growth and peak demand growth. This approach also creates issues relating to different size customers imposing different costs on the network and possible perverse incentives in relation to defining (aggregating and splitting) "customers".

Recommendation 5: Link revenue cap to economic growth.

> **In applying a revenue cap, the AER should consider applying adjustment factors to insulate Distributors from large divergence of actual peak demand from forecast**

> **peak demand. This could, for example, be applied by linking the annual revenue cap to movements in measures of economic activity, such as Gross State Product.**

The AER has already indicated in its proposed transitional arrangements for the forthcoming NSW 2009–10 to 2013–14 distribution determination that it will apply a weighted average price cap. In such circumstances, where it will be impossible to apply a revenue cap to Distributors, the regulatory structure should include other mechanisms to counter the disincentives for DM and the incentive it creates for Distributors to sell more electricity. A D-factor is an obvious candidate for such a mechanism.

This approach has been supported by the independent consultants appointed to advise the Ministerial Council on Energy on network incentives for demand management. In their report, NERA Economic Consulting state:

> However, in light of the disincentives for the Distributors to promote DSR …under the price cap form of control, we see merit in arrangements that allow a Distributor to recover the within-period revenue foregone as a consequence of implementing DSR projects. Such an arrangement could operate along the lines of the relevant component of the NSW D-factor scheme … (NERA Economic Consulting 2007, p. 49).

NERA goes on to suggest that the D-factor, by allowing recovery of both DM program costs *and* retaining avoided network capital expenditure, is effectively double counting and over-rewards DM (NERA Economic Consulting 2007, p.26). There is some theoretical merit to this argument. In principal, the D-factor allows the Distributors to garner all of the distribution network benefits of DM for itself. Most jurisdictions in the US that have positive incentives for DM limit the utility to collection of program costs plus some relatively small share of the net savings (typically 10%–30%).

However, in practice, within the current Australian context, providing strong incentives for Distributors to implement DM is warranted to address the range of other disincentives and barriers that are still weighted against DM. It should also be noted that allowing Distributors to garner the Distribution network benefits still allows the majority of avoided electricity supply costs (those associated with generation, transmission and system and market operation) to accrue to the consumer. Moreover, if the incentives for the Distributors to undertake network DM are not sufficient to drive DM action, then there will not be any benefits to distribute.

In conclusion, in the absence of more direct decoupling mechanisms such as a revenue cap, a D-factor mechanism that allows recovery of electricity sales foregone due to DM is essential. In the current DM market context, the D-factor should also allow recovery of DM program costs up to the value of avoided network costs, as does the current NSW D-factor.

When and only when an efficient level of investment in DM has been attained should the continued provision of such compensation support mechanisms be reviewed.

Recommendation 6: Use D-factor if revenue cap precluded.

> **In circumstances, where it is not possible to apply a revenue cap** (for example, where a commitment to a price cap has already been made, as in NSW for the forthcoming regulatory period)**, other revenue decoupling or "lost revenue adjustment" mechanisms should be applied (such as the NSW D-factor).**

A useful enhancement to the D-factor approach would be to "prime the pump" by stipulating a annual "before the fact" or "ex ante" expenditure allocation specifically for Distributors to undertake DM. This approach is similar to that adopted by ESCOSA's $20 million DM Fund in

South Australia. However, if this expenditure is not undertaken in any given year, then it should be returned to customers through a “negative pass through”. In order to encourage investment in DM by Distributors uncertain about cost recovery, this expenditure could be subject to an ex ante assessment by the AER as representing genuine efforts to develop effective DM, rather than made “at risk” subject to ex post (“after the fact”) assessment of its effectiveness.

An appropriate level may be in the order of 2% to 4% of the projected network capital expenditure for the first few years of a pricing determination. Such a mechanism should only be applied as a short-term mechanism to stimulate “learn by doing” DM investment. In general, it is important that incentives are provided to maximise the effectiveness and minimise the cost of DM rather than merely to spend a given amount on DM. The effectiveness of such a mechanism should be reviewed at the end of the regulatory period.

It should be also made clear that DM expenditure over this ex ante allocation is encouraged subject to the normal DM expenditure efficiency tests.

Recommendation 7: Create a “use it or lose it” component in the D-factor.

Where a “lost revenue adjustment” mechanism (such as the D-factor) is established, it should be applied with a default ex ante allocation on a “use it or lose it” basis that assumes some (non-trivial) level of DM will be undertaken by the Distributor. A D-factor of at least 2% of annual proposed capital expenditure could provide a reasonable default ex ante allocation.

As noted in Chapter 6, the current D-factor in NSW only permits the Distributors to recover the costs of DM initiatives where they can be shown to be cost effective in network constrained areas. This short term focus results in large lost opportunities relating to energy efficiency and peak load DM measures that deliver longer term load reductions well in advance of a network constraint emerging. These lost opportunities include energy savings improvements that are easily made when buildings are designed and built and equipment and appliances selected but prohibitively expensive later on.

The D-factor should therefore be extended to allow Distributors to recover costs associated with “long term DM” in relation to low cost DM opportunities that would otherwise lost if they are delayed until a local network capacity constraint emerges. Distributors should be permitted to recover (via the D-factor) associated electricity sales foregone for the remainder of the regulatory period, plus the direct cost of the DM measure up to a default long-term Avoided Distribution Cost (ADC). This long-term default ADC should be set at a modest level that reflects the long term average value of avoidable network investment. As with other aspects of the D-factor, care should be taken to minimize “free riders”, where Distributors invest in DM measures that would have been undertaken by customers without support by the Distributor.

Recommendation 8: Allow recovery of long-term DM costs in D-factor.

Distributors should be permitted to recover, through the D-factor, costs associated with low cost “long-term DM” opportunities that would otherwise be lost if they are delayed until a local network capacity constraint emerges.

7.3 Regulating for efficient capital expenditure and network planning

While the short-term incentives associated with the annual regulatory price control formula discussed above are important, the longer-term incentives associated with how the network investment and planning are regulated, reviewed and approved are equally crucial.

It should be recognised that Distributors in Australia have relatively limited experience in supporting DM. Imposing new risk elements on networks for them to manage may simply drive the networks to rely more heavily on network technologies with which they have greatest familiarity, to the exclusion of DM.

In relation to the perceived lack of firmness of DM, it should be noted that networks themselves only achieve their required level of "firmness" through redundancy and overcapacity. It is unrealistic and inappropriate to expect individual DM elements to provide the same level of firmness as an integrated system of network elements. Just as the different elements of supply infrastructure need to be combined to deliver adequate reliability, DM elements need to be aggregated and integrated, both with each other and with the network, to achieve optimal firmness and efficiency.

It is also important that the value of other benefits of DM is taken into account. DM enjoys a number of the relatively lower risks attributes. For example, fuel price and carbon risk can be significant factors for any major fossil-fuel based generation option, but are both often non-existent for DM. The use of supply-side options to meet demand results in transmission and distribution network losses. Because DM does not involve these costs, a DM-related 1MW reduction in demand is, can be equivalent to an increase in supply of 1.05MW (off peak) to 1.4MW or higher (on-peak). So 1MW of DM can offset up to 1.4 MW or more of generation and network capacity.

Recommendation 9: Allow Distributor savings from DM to be carried forward.

> **The AER should ensure that Distributors are permitted to carry over efficiency benefits from DM, such as deferral or avoidance of capital expenditure, from one regulatory period to the next, on no less favourable terms than they are able to continue to earn a return on network capital investment from one period to the next.**

The draft distribution regulation rules under which the AER will operate, state:

> "The distribution revenue rule should include operating and capital expenditure assessment criteria that require the AER to be satisfied that the forecast expenditure reasonably reflects efficient non-network alternatives available to a Distributor."

Such "expenditure assessment criteria" need to be sufficiently specific to ensure that the consideration of "efficient non-network alternatives" is more thorough than the cursory review that has often been applied in the past.

It is essential that DM is considered on an equal basis with network infrastructure options in the context of prudence reviews of past and proposed investment.

Recommendation 10: Ensure balanced prudence review of capital expenditure.

> **Recognising that short-term incentives are likely to have little impact unless complemented by longer-term incentives, the AER should ensure that the review of prudence of past and projected capital expenditure involves a thorough assessment of the opportunities for deferring capital expenditure through DM. These reviews should be conducted by experts with a demonstrated balanced understanding of the theory and practice of DM.**

Recommendation 11: Require Distributors to demonstrate efforts to procure DM.

> **The AER should require Distributors to demonstrate that they have undertaken reasonable efforts to identify and procure cost-effective DM, particularly in the context of anticipated network constraints and proposed new network investment. Such efforts should include direct DM offers to consumers, DM programs developed by the Distributor and DM proposals solicited from other parties.**

Disclosure and publication of relevant network data must also be required to allow a thorough and timely assessment of DM options to be undertaken. The NSW *Demand Management Code of Practice for Electricity Distributors* and the South Australian *Industry Guideline 12: Demand Management for Electricity Distribution Networks* provide useful precedents for the minimum level of disclosure.

Recommendation 12: Inform the DM market.

> **The AER should seek to inform the market for DM options by requiring Distributors to publish detailed information annually about the current capacity of the distribution network, current and projected demand and possible options to address any emerging constraints. (The NSW *DM Code of Practice for Distributors* and the South Australian *Guideline 12* provide sound precedents for such information disclosure.)**

7.4 Public reporting and review

A key barrier to the development of network DM is the perception of risk that is created by a lack of familiarity with DM. While there is ample overseas evidence and some local information (including that in Chapter 4) to suggest that DM can be extremely cost effective, the absence of comprehensive, reliable statistics and case studies in the public domain makes it much harder for both Distibutors and regulators to promote and support DM. It is therefore essential that the regulators recognise this barrier and facilitate the public provision of better, consistent and consolidated DM information.

In NSW at present, Distributors are required to report DM performance information to both the Department of Water and Energy as part of their Annual Network Management Reports and to IPART as part of their annual D-factor submissions. The reporting definitions and data requirements for these two purposes are different and in the case of the Annual Network Management Reports have changed significantly from year to year and generally do not relate to actual DM measures implemented and outcomes achieved. Even the D-factor submissions are based on expected rather than actual demand reductions achieved.

Recommendation 13: Ensure consistent Distributor DM performance reporting.

> **The AER should require Distributors to report annually on DM activities undertaken in relation to expenditure, peak demand and energy consumption reductions, value of electricity sales foregone, value of capital and operating expenditure avoided or deferred and efforts to identify and procure cost-effective DM. Such reports should be publicly available. The AER should issue a pro forma to encourage consistency in DM reporting. Reporting to the AER should be harmonised with any other DM reporting requirements.**

Recommendation 14: Conduct and publish annual AER DM Reviews .

In recognition of the relatively underdeveloped state of DM in Australia, the AER should monitor DM data provided by Distributors and compile a consolidated annual review to encourage mutual learning and allow the comparison of different policies and approaches between jurisdictions. (This will also assist in building understanding of DM potential within the regulatory community and among stakeholders.)

7.5 Complementary transitional measures to accelerate DM

The above measures represent important first steps in tilting the balance back towards a more competitive, sustainable and efficient electricity sector. However, alone they will not overcome the longstanding barriers to clean energy in the National Electricity Market.

Given that the process of reform required to establish a competitively neutral market for DM is likely to require years of sustained effort, complementary measures outside of the formal regulatory structure of the AER and AEMC will be required for the foreseeable future. These measures could include mandatory energy efficiency targets and substantial funding support independent of the utilities to develop demand management and distributed generation in the near term. It was in recognition of this principle that such "public benefit funds" have been created in some two dozen states of the USA as well as in NSW in the form of the Energy Savings Fund (now the Climate Change Fund).

Recommendation 15: Complementary transitional measures to accelerate DM.

Recognising that the above measures are designed simply to address existing barriers to efficient DM in the economic regulatory environment, and that the DM market in Australia is currently underdeveloped, Federal, State and Territory Governments should establish complementary transitional measures to create positive incentives to develop DM quickly.

Recommendation 16: Put an appropriate price on greenhouse gas emissions.

In the interests of economic efficiency, and recognising the high economic cost that climate change is now expected to impose on the Australian and global community, the Australian Government should ensure that the price of greenhouse gas polluting activities, such as fossil fuel based electricity generation, includes the full cost of the associated greenhouse gas emissions. This could be achieved by introducing an emissions trading scheme or a carbon tax.

Appendix 1: Proposed additions to support DM in the National Electricity Rules

The Australian Energy Regulator must regulate Distributors in accordance with the National Electricity Distribution Revenue and Pricing Rules. These rules currently make little mention of Demand Management. The following comments relate to the specific content of the Rules . The following comments have been made on the basis of what seems a reasonable, interpretation of "*the long-term interests of consumers of electricity*", consistent with the COAG policy statements above.

6.1.0 Definitions
Insert:

> *demand management* means assisting customers to reduce their demand for electricity by means of financial payments or incentives, network support payments, information and education initiatives, tariff design or other measures to encourage end-use energy efficiency, peak load reduction, demand-side response or distributed generation (of less than 30 MW generating capacity).

6.2.5 Control Mechanism
Following paragraph (4), insert

(5) the need to support the long-term environmental sustainability of electricity supply;
(6) the need to encourage cost-effective *demand management*;
(7) any other factor the AER considers relevant

6.5.5 Efficiency benefits sharing scheme
Replace paragraph (b) with the following

(b) (1) An efficiency benefit sharing scheme may extend to efficiency gains and losses related to capital expenditure (but is not required to do so);
(2) An efficiency benefit sharing scheme must extend to efficiency gains and losses related to capital expenditure where this is necessary to give effect to paragraph (c).

In paragraph (c) add

(4) the need to ensure that *Distribution Network Service Providers* have effective incentives to support *demand management* wherever doing so is likely to be at least as cost effective as network capital expenditure, or wherever doing so is likely to lead to a lower overall cost to consumers than undertaking network capital expenditure

6.5.6 Forecast operating expenditure
Insert in (a)

(5) support *demand management* wherever cost effective.

Insert in (e)

(10) the appropriateness of the proposed level of expenditure on *demand management.*

6.5.7 Forecast capital expenditure
Insert in (a)

(5) support *demand management* wherever cost effective.

Insert in (e)

(10) the appropriateness of the proposed level of expenditure on *demand management.*

6.6.2 Service target performance incentive scheme
Insert in paragraph (b) (3)

(v) the extent to which *demand management* may assist in meeting service targets.

6.18.3 Pricing proposals

Insert in paragraph (b)

(8) support cost-effective *demand management.*

6.21.1 Prudential requirements for distribution network services

Insert after paragraph (b)

(1) Where negotiation is not successful and agreement is not achieved, either party to the negotiation may seek dispute resolution by the AER under clause 6.23.1.

S6.1.2 Information and matters relating to operating expenditure

Insert after paragraph (8)

(9) a forecast of expenditure on *demand management* and expected associated savings in operating and capital expenditure.

S6.2.2 Information and matters relating to operating expenditure

Insert after paragraph (6)

(7) the need to provide incentives to the provider to undertake efficient *demand management* expenditure.

Appendix 2: Background to creation of the NSW D-factor

(From: Independent Pricing and Regulatory Tribunal of NSW, *NSW Electricity Distribution Pricing 2004/05 to 2008/09, Final Report*,, June 2004)

8 PROVIDING INCENTIVES FOR DEMAND MANAGEMENT

Demand for electricity has become increasingly peaky. This has led to constraints in the capacity of the distribution network at certain times and in certain locations. In most cases, DNSPs have addressed these constraints (or potential constraints) by augmenting the network to increase its capacity. This has resulted in substantial increases in their capital expenditure and reduced their asset utilisation. (For example, 10 per cent of Energy Australia's network capacity is used for less than one per cent of the time.)

The Tribunal is concerned about the efficiency of this approach, and the effect it is having on the cost of electricity for end users. Its 2002 inquiry into demand management[107] found that Demand management options can be a more cost-effective way to relieve network constraints, and can improve capital efficiency and provide flow-on benefits to end users in the form of lower costs. However, DNSPs have undertaken few demand management activities in the current regulatory period. The 2002 inquiry also identified a range of barriers to the use of demand management options, some of which related to the current regulatory framework of network pricing.

In determining the new regulatory framework for 2004–09, the Tribunal has aimed to ensure that these regulatory barriers are removed, and to neutralise the potential disincentive for demand management created by the change to a weighted average price cap form of regulation (which links revenue to volumes sold). It considers that its final decisions represent a generous treatment of demand management activities. This generosity is warranted, at least in the short term, to help overcome the barriers to the greater use of demand management solutions in supplying network services and to support the emergent market for these solutions.

However, in the medium to longer term, as demand management becomes 'business as usual' for DNSPs, the Tribunal believes it will be more appropriate to treat demand management costs in the same manner as other costs.[108] For example, it considers it reasonable to expect that at the next regulatory reset in 2009, the DNSPs' forward-looking expenditure profiles will incorporate an appropriate mix of demand management and network build solutions, representing the least-cost approach to meeting expected demand. If this is the case, the notional revenue requirements for each DNSP will reflect this lower cost mix, so an on-going pass-through of demand management costs or foregone revenue will not be appropriate. It intends to examine this issue closely at the next regulatory reset.

In addition, while the Tribunal believes its determination is an important step in promoting demand management, this determination will not overcome all the barriers. As the Tribunal has noted previously, the development of an effective market for demand management solutions in NSW will require action by all those involved in the electricity industry. The DNSPs must seek out opportunities to use demand management options to reduce their operating and capital costs, and improve their planning processes and internal cultures to ensure that these options are well integrated into their planning processes. Retailers, customers, service providers and Government also have important roles to play[109].. The Tribunal's final decisions in relation to the treatment of

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[107] IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services - Final Report,* Review Report No. Rev02-2, October 2002

[108] This is in line with the view put forward by SKM in its report to the Tribunal, *Avoided distribution costs and congestion pricing for distribution networks in NSW*, November 2003

[109] See IPART, *Inquiry into the Role of Demand Management in the Provision of Energy Services - Final Report*, Rev02-2, October 2002, for possible steps these groups could take

demand management are set out below. The issues raised by stakeholders in response to the draft decisions, the Tribunal's considerations in making its final decisions, and the implications of these decisions are also discussed.

8.1 Final decisions

The Tribunal has decided that it will introduce a D-factor into the weighted average price cap control formula that allows DNSPs to recover:

- ***approved non-tariff-based demand management implementation costs, up to a maximum value equivalent to the expected avoided distribution costs***
- ***approved tariff-based demand management implementation costs***
- ***approved revenue foregone as a result of non-tariff-based demand management activities.***

The D-factor will be calculated using the following formula:

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

Where:

D_{t+1}	**is the D-factor to be included in the price control formula for Year *t+1***
AF Revenue t-1	**is the amount approved by the Tribunal for recovery by the DNSP of foregone revenue in Year *t-1***
AF Revenue 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 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**
SRRt	**is the smoothed revenue requirement for the DNSP for the Year t**
SRRt-1	**is the smoothed revenue requirement for the DNSP for the Year t-1**

The Tribunal has also decided to:

- **treat DNSP rebates and payments for load reduction as negative prices under the weighted average price cap**
- **establish a working group to examine DNSP network planning processes**
- **establish a working group to develop a methodology for assessing the economic prudence of energy loss management investment**
- **establish a working group on the calculation of distribution revenue foregone as a result of demand management activities**
- **accommodate a Government demand management fund, if introduced.**

Appendix 3: DM projects and investigations in NSW

NETWORK DEMAND MANAGEMENT UNDERTAKEN BY **Energy Australia**

DESCRIPTION & STATUS								PROJECTED OUTCOMES					
Financial Year	Location	Description	DM Type (PFC; Interruptible Load; Energy Efficiency; Local Generation; Load Shift; Permanent Load Shed; Pricing)	Network or Customer Site	# of sites	Duration of benefits (Years)	Status (initiated; ongoing; completed; pilot completed; offered; contracted; discontinued)	Demand reduction kVA	Demand reduction kVAr	PV of Demand Management Program cost $	Avoided distribution cost (PV of deferred CAPEX+ OPEX) $	Estimated change in GHG emissions* Tonnes/year	Comments
Before D-Factor Commencement													
2000-01		off-peak load control	Load Shift	C				800MW		$ 1,530,000	$ 7,080,000		
		risk analysis of zone substations	??	N						$ 800,000	$ 6,600,000		
2000-01	**TOTALS**									**$ 2,330,000**	**$ 13,680,000**		
2001-02	Lower Hunter	efficency for low income rentals	Energy Efficiency	C									
		controlled off-peak load	Load Shift	C				800 MW					
	City South, City Centre, Avoca		Power Factor Correction (PFC)	N						$ 2,260,000	$ 5,180,000		
	North Ryde	Dispatch standby gen	Local Generation	C									
		continuation of off-peak load control program	Load Shift	C						$ 1,800,000	$ 7,840,000		
2001-02	**TOTALS**									**$ 4,060,000**	**$ 13,020,000**		
2002-03	Erina		PFC	N			completed			$ 610,000	$ 1,290,000		
	West Gosford		PFC	N			completed			$ 490,000	$ 1,290,000		
	North Ryde RSL	Dispatch standby	Local Generation	C			contracted						
		hot water load control	Load Shift	C				800MW					
2002-03	**TOTALS**									**$ 1,100,000**	**$ 2,580,000**		
2003-04	Brookvale/DeeWhy		PFC	C	12	n	completed	1,600		$ 25,615		1400/n	
	Manly	dispatch standby gen	Local Generation	C	1		ongoing	1,000		$ 310,000			
	Brookvale/DeeWhy	std offer for commercial customers to reduce demand for $200/kVA up to 2 years	Energy Efficiency	C			offered	1,500		$ 360,000	$ 550,000		Combined cost
	Central Coast		PFC	C	100	n			7000	$ 176,700	$ 450,000	3500/n	
	CBD	pilot complete -modify BMS for dispatched demand curtailment; demand reductions no longer persist	Interruptible	C	4		discontinued	300		$ 486,281	$ -		
	Nelson Bay		Local Generation	N	3 gen sets		completed	3,000		$ 1,433,092	$ 1,460,650		
	North Ryde	dispatchable standby gen - pilot complete-demand reduction exists but no longer required	Local Generation	C	1		discontinued	1,000		$ 112,264	$ -		
		Residential CFL Program	Energy Efficiency	C	all Res.		offered	6,600		$ 1,900,000	?		Estimated $1.5m in NGACS
	Kogarah Town Squar	Solar power- analysed potential	Local Generation	C									
		Load control - off-peak hot water	Load Shift	C			ongoing						
		efficiency awareness program	Energy Efficiency	C			initiated						
2003-04	**TOTALS**							**15,000**	**7,000**	**$ 4,803,952**	**$ 2,460,650**		
After D-Factor Commencement													
2004-05	Carlingford	Offer of PF correction	PFC	C	90	x	initiated		12,000	$161,000	$461,000	4800/x	
	Padstow	Offer of PF correction	PFC	C	8		initiated	1,000		$15,000	$595,000	640/x	
	Nelson Bay	Stage 2 (diesel) distributed generation	Local Generation	N		2yr deferral	completed	3,300		$1,327,098	$3,317,933		Stage 2 DM costs, full project benefits
	Medowie DG	(diesel) distributed generation	Local Generation	N		1yr deferral	installed	1,000		$541,023	$605,789		
	Wollombi DG	(diesel) distributed generation	Local Generation	N		2yr deferral	installed	1,000		$971,951	$1,066,611		
	Sefton DG	(diesel) distributed generation	Local Generation	N		1yr deferral	installed	3,300		$1,289,016	$1,667,521		
		interval meters for ToU tariffs	Pricing	C	16000								
		free residential CFLs	Energy Efficiency	C	1.3m	x	offered					200,000/x	funded primarily through NGACs
2004-05	**TOTALS**							**9,600**	**12,000**	**$ 4,305,088**	**$ 7,713,854**		
2005-06	Mona Vale		PFC	C	7	10	initiated		1,400				
	Mona Vale		Interruptible Load	C	1		initiated	400		$ 82,000	$ 488,000	80	combined
	Drummoyne	Res. CFL replacement	Energy Efficiency	C		6		1,000		$ 300,000	$ 515,000	6000	
	Leighton		PFC	C	11	10	initiated		2,800	$ 28,000	$ 272,000	160	
	Berowra/Pennant Hills/Hornsby		PFC	C	18	10	initiated		2,300	$ 41,000	$ 92,000	131	
	Hunter		PFC	C	43	10	initiated		4,300	$ 260,000	$ 450,000	245	
	Lower Hunter		PFC	C	62	10			11,000	$ 152,000	$ 275,000	627	
	Nelson Bay/Medowie/	distributed gen of 11.3 MW	Local Generation	N	4		ongoing	11,300					
	Sydney CBD	continued project and testing	Interruptible Load	C									
		hot water	Load Shift	C			ongoing						
		smart meters trial	Pricing	C	180k+								
		free residential CFLs	Energy Efficiency	C	1.1m	x	offered					500,000/x	funded primarily through NGACs
	Hunter Central Coast	REFIT- energy+water saving program	Energy Efficiency	C	14k	x	ongoing					65,000/x	funded primarily through NGACs
		Fridge retirement	Permanent Load Shed	C	1200	x	completed			$ 60,000		6,500/x	
2005-06	**TOTALS**							**12,700**	**21,800**	**$ 923,000**	**$ 2,092,000**		

NETWORK DEMAND MANAGEMENT UNDERTAKEN BY **Integral Energy**

DESCRIPTION & STATUS								PROJECTED OUTCOMES					
Financial Year	Location	Description	DM Type	Network or Customer Site	# of sites	Duration of benefits (Years)	Status	Demand reduction		PV of Demand Management Program cost	Avoided distribution cost (PV of deferred CAPEX+ OPEX)	Estimated change in GHG emissions*	Comments
								kVA	kVAr	$	$	Tonnes/year	
Before D-Factor Commencement													
2000-01	off-peak load control		Load shift	N						$820,039	$2,050,099		Annualised costs converted to PV assuming 5 equal payments of annualised cost, discounted at 7%
	9 major projects									$820,039	$6,315,432		
2000-01	**TOTALS**									**$ 1,640,079**	**$ 8,365,531**		
2001-02	Blacktown		Power Factor Correction (PFC)							$ 270,000	$ 4,000,000		
		Consolidated	PFC							$ 250,000	$ 3,600,000		
	ongoing - Seven Hills/Wetherill Park DM	misc DM								$ -	$ -		
	Penrith area	RFP for misc load reduction	Permanent load shed	C						$ -	$ -		
2001-02	**TOTALS**									**$ 520,000**	**$ 7,600,000**		
2002-03	Castle Hill	Customer DM pgm		C						$ 250,000	**$ 3,970,000**	?	
		consolidated - Zone substations	PFC	N			ongoing			$ 3,000,000	**$ 33,785,000**	6,400	
2002-03	**TOTALS**									**$ 3,250,000**	**$ 37,755,000**		
2003-04	Blacktown	RFP proponents to undertake audits and obtain customer commitment to implement cost effective measures		C		10	contracted	3,700		$ 420,000	$ 528,000	7,000	
	Seven Hills-Extension of DM project	renewd agreement with customer	Load shift	C	1			3,500		$ 65,000	$ 175,000	-	
		consolidated customer PF	PFC	C		10		2,600		$ 100,000	$ 400,000	225	
2003-04	**TOTALS**					**20**		**9,800**		**$ 585,000**	**$ 1,103,000**	**7,225**	
After D-Factor Commencement													
2004-05	Parramatta CBD	misc dm		C		10	contracted	4,900		$500,000	$1,191,000	6,500	costs over 4 years
	Wetherill Pk Ind. Area	misc dm		C			contracted	7,000		$650,000	$1,149,000		costs over 3 years
	Nowra comm.ctr.	misc dm		C			contracted	3,500		$300,000	$461,000		costs over 4 years
	Norwest Biz Pk	misc dm		C				14,000		$1,100,000	$2,063,000		costs over 1 years
	Westmead hospital	Local generation + permanent load shed		C	1	10		10,000		$430,000	$867,000	20,500	costs over 4 years
		consolidated Customers	PFC	C				1,940		$168,000	$570,000	168	
2004-05	**Totals**							**41,340**		**$ 3,148,000**	**$ 6,301,000**	**27,168**	
2005-06	Campbelltown	misc id'd by audits by project proponent of RFP		C		10	initiated	3,900		$ 480,000	$ 562,000	14,500	
	consolidated	Encourage customers to install PFC	PFC	C		?		2,100		$ 82,000	$ 542,000	188	
2005-06	**TOTALS**							**6,000**		**$ 562,000**	**$ 1,104,000**	**14,688**	

NETWORK DEMAND MANAGEMENT UNDERTAKEN BY **Country Energy**

DESCRIPTION & STATUS									PROJECTED OUTCOMES					
Financial Year	Network	Location	Description	**DM Type** (PFC; Interruptible Load; Energy Efficiency; Local Generation; Load Shift; Permanent Load Shed; Pricing, Loss reduction)	Network or Customer Site	# of sites	Duration of benefits (Years)	**Status**	Demand reduction kVA	Demand reduction kVAr	PV of Demand Management Program cost $	Avoided distribution cost (PV of deferred CAPEX+ OPEX) $	Estimated change in GHG emissions* Tonnes/year	**Comments**
Before D-Factor Commencement														
2000-01	AE		improve load control eg off-peak hot water	peak reducing							$ 400,000	$ 980,000		improve load control eg off-peak hot water
	AE	Cudal	Diesel Generation	Local Generation							$ 400,000	$ 1,500,000		defer system upgrade
	AE		new network pricing - tou pricing								$ -	$ -		
2000-01	AIE	none	(some pf and load control work)								$ -	$ -		
2000-01	GSE	Wagga Wagga	defer expenditure on zone substation	Load shift							$ 1,500,000	$ 10,500,000		
	GSE		small number of innovative projects								$ 394,000	$ 3,580,000		
2000-01	NP	Lismore	Demand shifting plant								$ 1,310,000	$ 2,710,000		
	NP		Other small DM projects incl. load shifting	Load Shift							$ 886,600	$ 1,842,300		
	NP		misc RE and technology promotion/development								$ 340,000			
2000-01		**Totals: aggregating Advance Energy (AE), Australian Inland Energy (AIE), Great Southern Energy (GSE) and North Power (NP)**									**$ 5,230,600**	**$ 21,112,300**		
2001-02			transfer large customers to demand tariffs	Pricing										
		Boggabri		PFC							$ 35,000	$ 724,000		capacitors
			smaller projects	?							$ 1,370,600	$ 1,744,206		
2001-02		**TOTAL**									**$ 1,405,600**	**$ 2,468,206**		
2002-03			consolidated relays	Load Shift	N			completed			$ 560,880	$ 1,500,000		
		Yanco	Rockdale Beef Abottoir	various				completed						projects by CE's subsidiary Energy Answers
			2 large customer sites	PFC	C			completed						projects by CE's subsidiary Energy Answers
	AE	NIL												
2002-03		**TOTAL**												
2003-04		Binda Bigga	Residential+commercial - conversion to gas +	Permanent load shed				initiated	100		$ 108,000	$ 454,000		heads of agreement signed with SEDA
		Marulan	customer deisel gen	Local Generation				ongoing			$ -	$ 250,000		
		Bega	gas turbine	Local Generation				??						"investigation" reported as "implemented"
		Casella Vines	HV connection	Loss reduction		1		completed			borne by client	$ 1,000,000		re-connect to HV to meet additional 3MVA loa
		Tritton Mine	demand curtailment	Interruptible load		1		contracted				$ 2,800,000		
		Coolah	Photovoltaics	Local Generation		1		completed		16	$ 100			
2003-04		**TOTAL**							**100**	**16**	**$ 108,100**	**$ 4,504,000**		
After D-Factor Commencement														
2004-05			Consolidated-control gear	Load Shift					*1,600*		$710,000	$3,200,000	-	
		Riverina	Residential-convert heat/hot water to gas	Permanent load shed	C	500	10		*1*		$0	$1,000,000	2,500	
		Bathurst Green Towns	trial …				7		?		$125,000	?	1,400	?=to be assessed during trial
			Street lighting- lamp replacement on behalf of street-lighting customer	Energy Efficiency				ongoing						
2004-05		**TOTAL**							**1,601**	**0**	**$ 835,000**	**$ 4,200,000**	**3,900**	**discrepancies with Country figures**
2005-06			Consolidated	Load Shift	C				1,600		$ 650,000	$ 3,200,000	-	
			consolidated - PF & upgrades	PFC	C				2,800		$ 4,000,000	$ 3,340,000	7,000	
			consolidated- misc negotiated		C				1,800		minor	$ 900,000	150	
			consolidated- Fuel substitution	Local Generation	C				200			$ 400,000	300	cost borne by gas distributor
2005-06		**TOTAL**							**6,400**	**0**	**$ 4,650,000**	**$ 7,840,000**	**7,450**	

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Does Current Electricity Network Regulation Actively Minimise Demand Side Responsiveness in the NEM?

A report

for the

Total Environment Centre

Prepared by

Headberry Partners and Bob Lim & Co

June 2008

Preparation of this report has been partly funded by the National Electricity Consumers Advocacy Panel. The support of the Advocacy Panel is gratefully acknowledged by the Total Environment Centre.

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The content and conclusions reached in this submission are entirely the work of the consultants.

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Contents

Executive Summary

Under the current regulatory arrangements for network service providers (NSPs) in the National Electricity Market (NEM), there is a disincentive for demand management (DM) through the use of the **Building Block** (BB) approach to regulatory review. There is an active incentive for the NSP to find network solutions through new capital expenditure proposals, as this increases the NSP profitability. This occurs because most DM programs used by NSPs are opex based, and the allowance for opex is provided for only at cost and as a result does not include any profit. This creates an active disincentive embedded in the BB approach against DM.

This disincentive is further reinforced when the BB is combined with a **price cap** (as opposed to a revenue cap), as it encourages increased consumption and demand. Using a price cap approach with a DM program requires an ability on the part of the regulator to identify any revenue lost to the NSP from a DM program and to implement a program to allow the NSP to recover this lost revenue. Such an approach has the potential to increase the “gaming” an NSP might undertake to maximise its revenue stream, and does not reimburse the price capped NSP for the loss of upside revenue potential.

A **revenue cap** approach suffers from the inherent dis-incentives in a BB approach to DM, but as the BB approach allows transparency and for programs to operate in parallel, a BB approach combined with a revenue cap provides a “least worst” outcome for implementing a DM program which has some prospect of real success.

A **total factor productivity** (TFP) approach has the potential to be neutral in relation to DM, but as it requires the use of a price cap approach (which incentivises greater demand and consumption) it also encourages increased consumption and demand. A TFP program also has a number of other disadvantages that need to be assessed in light of the overall goals of encouraging DM. In particular, it is not a tool which provides transparency and therefore might not provide the necessary transparency required to encourage DM options (and energy efficiency).

There would appear to be no simple solution to overcoming the inherent disadvantages that the BB, TFP, revenue cap and price cap approaches impose in providing dis-incentives to DM. The most likely approach to be successful in the NEM is that used by the ESCoSA for its pilot program for DM, which provides a parallel program supervised by ESCoSA to bring about defined outcomes. But it is, nonetheless, a rather modest program, and it still does not address the essential problem that DM is likely to reduce the potential of revenue increases inherent in a price capped NSP.

Overseas demand management approaches such as that used by the Californian Public Utilities Commission scheme appear to be more successful than most. This scheme operates under an energy efficiency policy framework mandated by the government. The regulatory framework established by the CPUC to meet the policy goals provides a high powered incentive scheme with financial penalties for poor performance coupled with financial incentives for out performance.

This program operates across the entire operation of the Utilities operating in the State and so allows the Utility to accrue benefits from each element of its activities. Such an approach is significantly weakened under the disaggregated approach used in the NEM. It should also be noted that the program addresses much more than DM, as it incorporates the renewable energy program and energy efficiency goals, which encompass both consumer efficiency and network efficiency. Notwithstanding these observations, it is possible that such an approach could be tailored to incentivise NSPs to improve network and consumer efficiency within the NEM.

Consideration needs to be given to combining mandated energy efficiency targets in the NEM with the DM measures currently implemented by ESCoSA and the CPUC, to drive a more powerful DM approach in the NEM.

DM programs would be even more effective if they were driven by an over-arching energy policy requirement for achieving energy efficiency targets across the entire electricity supply chain.

This report makes the following recommendations:

1. Separate and parallel demand management incentive schemes, established and overseen by regulators, are the most effective way of ensuring demand management initiatives by network businesses

2. The use of a revenue cap, removing the incentive for networks to increase demand and consumption, would be required in addition to DM incentive schemes

3. Demand management programs for each network business might contain the following features:

    a. Identification of demand management options and target outcomes, and to establish a pact between regulators and network businesses

    b. Inclusion of a fixed amount of funding for DM to be included in the allowed revenue for the network business

c. Incorporation of a program of benefit sharing, and financial incentives and penalties

d. Implementation as part of the regulatory reset

4. An overarching energy policy requirement should be set by government for actioning energy efficiency targets across the entire electricity supply chain.

5. Consumers should engage in regulatory reviews where the Building Block approach is used and to contest network business' capital expenditure and rate of return claims

6. Consumers should engage in regulatory reviews using the price cap form of regulation (under the Building Block approach) to contest claims with respect to pricing methodologies and cost allocation mechanisms

1. Introduction

This report has been initiated by the Total Environment Centre (TEC)[1] to assesses the relative merits of the price cap [including Total Factor Productivity (TFP)] and the revenue cap, taking into consideration the goals of the participating groups and the range of matters that the Australian Energy Regulator (AER) must consider when assessing the merits of a revenue reset application for electricity distribution networks. The report is also aimed at increasing the capacity of consumer groups to understand and critique the various regulatory approaches in use in the National Electricity Market (NEM).

The TEC considers that there is a strong need for a regulatory approach that provides stronger economic signals for all concerned with the use of electricity (including governments, regulators, supply side businesses and consumers) and to encourage demand management, including an overall reduction in electricity usage.

TEC is looking to play a greater role in reducing network constraints and improving the operation of the electricity supply system. DM has essentially two basic elements to it. The first is to improve efficiency in the use of electricity and the second is to improve the use of existing electricity assets by improving the load factor in the system.

One of the causes for the increasing cost of electricity in recent times has been the increasingly common reduction in the average load factor in electricity supply systems largely due to the impact of the high penetration of air conditioning and heating in the domestic residential market. This reducing average load factor increases overall costs to consumers from two main sources, generation and networks:

- As the load factor reduces, there is a greater need for more **generation** which operates for increasingly shorter periods (e.g. to meet summer and winter peak demands) in order to meet the needs of consumers. This is currently economically inefficient as the result is significant amounts of generation plant lying idle for extended periods of time.[2] This idle plant incurs costs even when not operating, and this cost must be recovered from consumers, thereby increasing the overall cost of electricity.
- To meet these short term spikes in demand the **networks**, which transport electricity from generators to consumers, must be sized to meet these short term demands for electricity. The alternative is that effective DM programs must be

[1] Funding for this report has been provided by the National Electricity Consumers Advocacy Panel.
[2] Introduction of carbon trading is likely to have a commercial impact on which generation plant lies idle, as including carbon costs will vary the dispatch ranking of generation, and the resultant increased costs are likely to affect power demand.

implemented to reduce demand or loss of supply will result. This requires the networks to invest in order to have the capacity to carry higher levels of electricity. Again, this is economically inefficient and augmenting networks for these short term peaks in demand also increases overall costs to all consumers.

There are a number of ways that the average load factor can be increased:-

1. Reduce demand during periods when the system demand is at the highest levels (peak time demand reduction)

2. Encourage consumers with a poor load factor to generate power to meet their needs and so use the network less (self generation)

3. Move demand from high demand periods to low demand periods (load shifting)

Reducing overall energy consumption by carrying out permanent energy efficiency improvements is a goal that provides distinct environmental benefits and should be seen as a fundamental element of demand management.

Collectively, these represent the main demand side responses that are possible in the electricity system.

However, the opportunity for demand side responsiveness is being minimised (and even discriminated against) under the current regulatory environment.

All consumers have the ability to provide demand side responses, but there are impediments to their doing so. Such impediments include the capital resources required to implement some solutions; an inability to know (or even being able to recognise) when the system needs their assistance; and the limited alternatives to using electricity at certain times, such as for lighting, heating or cooking of meals.

In addition to the general burgeoning use of electricity over recent years, there is a strong trend in the use of electricity in ever increasing amounts for very short periods of time. This has created a need for the building of more energy infrastructure overall, and a need to provide increased amounts of fast start generation (which frequently is quite energy inefficient) to operate for short periods of time (demand spikes). This demand pattern also imposes a need to augment the electricity networks to facilitate these demand spikes.

The current tools available to the economic regulator in assessing applications from distribution network service providers are prescribed by the National Electricity Rules. Using what is generally described as the “Building Block” approach, the regulator has the task of determining how much cash the regulated business is allowed to have each year (for a period of five years) to provide the service that consumers require. The determination is arrived at after each cost element of the business is added up and an appropriate rate of return applied to arrive at the maximum required revenue for the business.[3]

A transmission network service provider is only permitted (under the National Electricity Rules) to use a revenue cap approach to recover the allowed revenue, whereas a distribution network business is able to recover its allowed revenue using either a **revenue cap** or a **price cap**. The decision to use a revenue cap or a price cap for the recovery of distribution network revenue is left to the regulator, the jurisdiction or the business, or a combination of these.

The reason behind using a **revenue cap** is that the revenue allowed to be collected is fixed by the regulator, regardless of any change in the amount of electricity carried by the network during the regulatory period, which is commonly a period of five years. Any over or under recovery of revenue in one year is adjusted in the following year to ensure that the business only recovers the actual revenue determined by the regulator. Effectively, a revenue cap therefore places the risk with consumers for the amount of electricity carried as it provides an incentive on consumers to increase usage, but any reduction in usage provides no benefit to consumers at all.

A **price cap** allows the regulated business to vary the amount of revenue it collects depending on the amount of electricity carried by the network. If the network carries more electricity then the revenue collected by the business will be higher than the revenue estimated by the regulator. The business is permitted to retain the over recovery, thereby incentivising the business to increase the amount of electricity carried on the network. Equally, if there is less electricity carried, then the business will recover less revenue.

This approach provides an incentive for the business to encourage consumers to use more electricity, but passes the risk of the estimated amount of electricity carried on the network from consumers to the business.

The following map shows where the price cap and revenue cap forms of regulation are used for distribution networks in the NEM jurisdictions.

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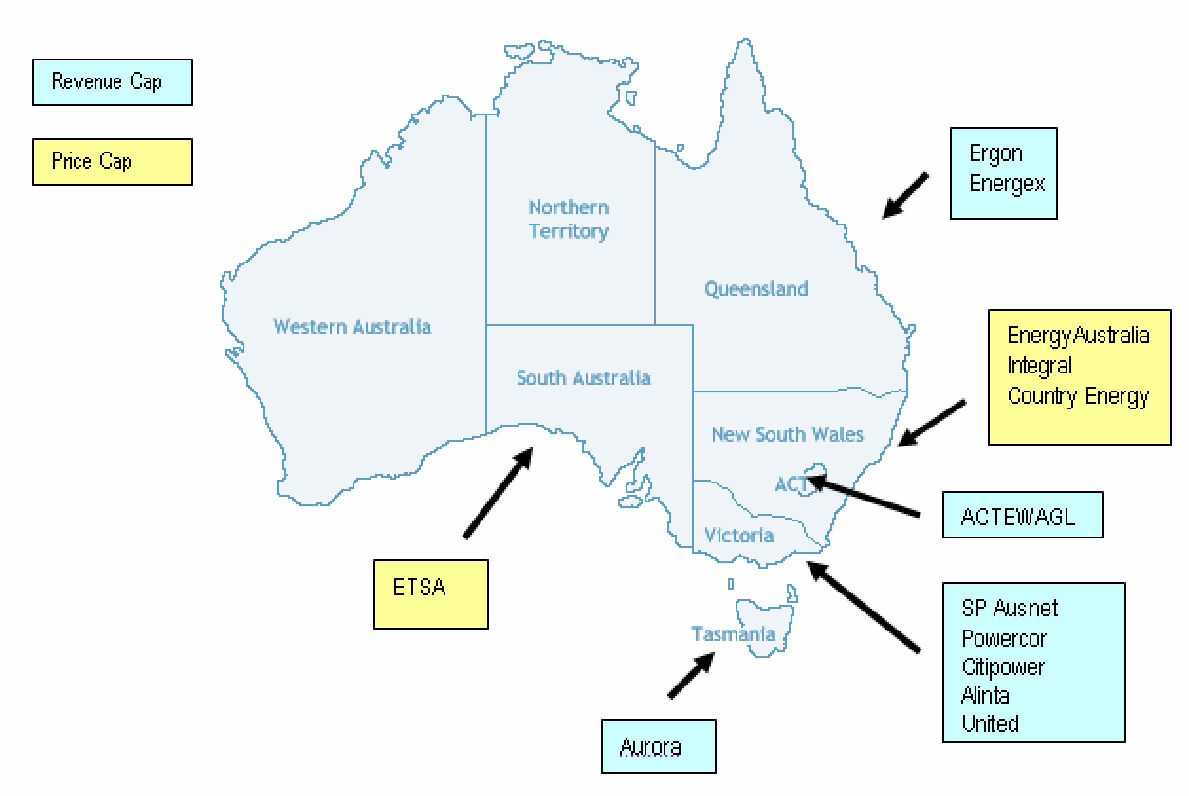
[3] A more detailed explanation of the **Building Block** approach, the **revenue cap**, the **price cap** and **TFP** are included in Appendices 1,2,3 and 4 respectively, together with an assessment of the advantages and disadvantages of each approach. These explanations were prepared to inform participants at the second forum run by TEC to critique the various regulatory approaches used.



There has been a recent move towards supplementing the Building Block approach for setting revenue with an approach called **Total Factor Productivity** (TFP)**.** TFP is a more streamlined approach to regulation and is applicable only to the price cap form of regulation.[4]

The TEC commissioned Bob Lim & Co and Headberry Partners (consultants) to identify whether one regulatory approach provides a better basis than another in providing the optimum signals to network owners to encourage the greater incidence of demand management (and by doing so achieve the defined NEM goals of improved efficiency in the use of electricity). At the same time, the TEC recognises that varying the approaches that have been in use in the different NEM jurisdictions to encourage more DM, might increase the cost per unit of electricity supplied to consumers and the impact of this would fall more heavily on disadvantaged consumers (even though total consumption would decrease per consumer and across the network).

This report assesses the relative merits of the different regulatory approaches used in the NEM in relation to DM[5], as well as reviewing some of the primary approaches

[4] Appendix 5 contains a description of the use of TFP in some overseas jurisdictions.
[5] See in particular Appendix 5 which discusses DM as used in some overseas jurisdictions

used overseas to engender DM. The report covers the issues and questions raised in the TEC's terms of reference to the consultants (Appendix 12), and reflects the outcomes of two forums conducted by TEC which discussed these issues amongst organisations advocating increased efficiency in electricity use and production, and organisations advocating for consumers, in particular, disadvantaged consumers.

The report is structured to reflect the brief provided to the consultants by TEC and is as follows:

Section 2 Regulatory mechanisms and demand management

Section 3 What incentive schemes might deliver DM best?

Section 4 Which approaches are best for consumers, especially vulnerable consumers?

Section 5 Which overseas DM incentive schemes deliver better outcomes?

Section 6 What approach best meets the intent of the Rules?

Section 7 Conclusions and recommendations

2. Regulatory mechanisms and demand management

Which mechanism better encourages more efficient use of electricity and demand management, end user consumption and prices, and the balance between network costs and revenue?

Demand management within a network is characterised by a need to prevent demand exceeding the capacity of the network. The implicit incentive in network demand management is that the cost of providing network demand management will be lower than the cost of augmentation of the network to manage the increases in demand and consumption.

The National Electricity Rules (the Rules) currently require the AER to establish the revenue permitted for a network using the **Building Block** approach, applying a **revenue cap** for transmission networks and a **revenue cap** or a **price cap** for distribution networks.

2.1 The Building Block (BB)

The BB approach does not of itself discriminate for or against any specific aspect of the regulatory process. All it does is consolidate amounts of revenue required for a network to provide the service expected of it. It is the way that the regulator addresses each of the components of the BB that provides the discrimination.

The Rules prescribe principles emphasising the importance of providing incentives to the networks to operate efficiently (in economic terms). Thus, it is essential to assess each element of the BB to determine if there is a basis for any view that there is discrimination within the Rules and in the way they are applied.

In the BB approach, the separate main elements[6] determined by the regulator are:

- Return on capital
- Return of capital
- Capital Expenditure (capex)
- Operating Expenditure (opex)
- Efficiency incentive (EBSS – efficiency benefit sharing scheme)
- Service performance penalty/bonus

[6] See glossary for an explanation of each term used.

Of the above elements, the regulator can (intentionally or unintentionally) discriminate against demand management through application of the following:

- The determination of the rate of return of capital
- The ex ante approach to capex determination
- The service performance determination
- The application of the EBSS

2.1.1 The rate of return of capital

The rate of return of capital (the weighted average cost of capital – WACC) has embedded in it all of the base profit the Network Service Provider (NSP) receives for providing the service. Compared to this, the allowance for opex is provided for only at cost, and therefore does not include any profit to the NSP for spending on any element included in the opex allowance. This approach, therefore, implicitly incentivises spending capital.

Therefore, the BB approach has an active incentive for the NSP to find network solutions through new capital expenditure proposals, and as many DM programs are opex based rather than network based, there is an active disincentive embedded in the BB approach against DM.

2.1.2 The ex ante approach to capex

The ex ante capex program provides the NSP with the ability to spend capital within the regulatory allowance but with no subsequent assessment of its economic efficiency or prudency, i.e. there is no ex-post audit at the next regulatory reset. The BB approach permits the NSP to provide the regulator with its anticipated capex needs (i.e. capex forecasts for the new regulatory period) but there is no compulsion on the NSP to spend on the projects it used to develop its capex allowance, and it is able to use the capex allowance on any project it sees appropriate.

The Rules allow an automatic roll forward of all capex regardless of whether the capex was within or exceeded the allowance in the regulatory reset. Even if the capex exceeded the regulatory allowance, the capex will be rolled forward as if it had been approved in the previous regulatory period.

The regulator is not permitted to penalise the NSP if the capex program does not follow the program used to develop the revenue, even if the actual program provides an additional net financial benefit to the NSP arising from any delays in implementation (e.g. when capex is implemented in the fourth year instead of the planned first year of a regulatory period). Thus the actual capex program can be skewed to maximise the commercial benefit of delaying the investment program and by “back end” spending. Another example is where a network solution is preferred by the NSP but the capex was not included in the regulatory program. In this case, the risk to the NSP can be minimised by implementing the capex in the final year of the regulatory period. As assets have a 40+ year life (and therefore the return on the asset will be over that period) the loss of one year's (or even two years) return on an asset could be readily offset by **not** implementing a project which delivers no profit at all (such as if it was included in the opex).

Provided that the total amount of capex is spent within the regulatory period, there is no assessment as to whether the capex achieved its expected result, whether the timing was implemented to minimise any risk to the NSP, or whether the capex was spent wisely[7].

The ex ante approach effectively approves any capex incurred in the period, does not assess whether actual projects used to develop the capex program were implemented or if the project was the optimum solution. Therefore, if an NSP identifies that a network solution will deliver a better outcome for the NSP in terms of NSP long term profitability, the ex ante approach allows the NSP the ability to follow its preferred option, provided that the amount expended does not breach the Regulatory Test. Therefore, the ex ante approach to capex in the BB has also provides an active disincentive against DM.

This is supported by the lack of an ex poste approach to capex, particularly as it relates to DM alternatives, because it provides no oversight to ensure the NSP has implemented DM when DM is more cost-effective than augmentation.

2.1.3 The service performance incentive scheme

The service performance program implemented by regulators is effectively divided into two elements:-

1. Performance of the network to provide the service expected of the regulatory bargain, in terms of the capacity of the network and its ability to consistently to supply the network service. The service performance incentive scheme is determined in terms of reliability and availability, and there is a penalty/bonus arrangement which incentivises the NSP to meet its side of the regulatory bargain.

2. Performance of the NSP in terms of its customer relations. This is usually related to "guaranteed service levels (GSLs)". The GSLs are usually based on a payment to a consumer if the NSP fails to carryout an agreed action.

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[7] This is the intent of the Rules. The AER has advised that it will carryout some investigation of the capex program of the previous regulatory period as part of its assessment for future capex claims. This might provide some constraint on NSPs, but this is debatable.

The service performance scheme provides a bonus to the NSP for higher network reliability and availability than expected at the regulatory reset review, and so incentivises better service performance. This encourages the greatest level of reliability, which of itself is a reasonable approach and should in general be supported.

There have been wide ranging debates in the NEM comparing the reliability of non-network solutions to network solutions for network needs. The debates have included the claim frequently put by NSPs that embedded generation solutions are less reliable unless they are inclusive of 100% backup, and that demand response only can be provided if the DM responder is actually using the network at the time the DM response is required. This has resulted in the assertion that DM has implicitly less reliability than a network solution. Although these claims have not been substantiated by evidential support[8], the culture of support and familiarity with network approaches, combined with the performance incentive scheme, results in the favouring of network approaches over non-network solutions.

On the basis that network solutions are perceived to provide a higher reliability than non network solutions, the performance incentive scheme incentivises network solutions, as the NSP is required to take the risk (pay a penalty) if the performance is worse than the target, and is rewarded if performance is better than targeted.

Thus a side-effect of the performance incentive scheme is to discourage DM solutions by actively encouraging the approach that is perceived to be more reliable: ie by the use of network approaches.

2.1.4 The Efficiency Benefit Sharing Scheme (EBSS)

The purpose in applying the EBSS is to incentivise the NSP to spend less opex than has been allowed in the revenue reset. In principle, this approach encourages the NSP to operate at the level of opex that is most economically efficient, and therefore is to be supported.

The downside of this incentive scheme, however, is that any program that is included in the opex (such as DM) and which can be addressed in another way (such as by a network solution funded by the capex program) provides an incentive for network solutions over DM.

The basis for such an observation is that the opex allowance excludes any profit for an NSP whereas the capex solution has embedded within it a profit element which is included in the rate of return on capital used for a network solution. As the EBSS rewards a NSP for reducing its opex below that allowed for in the revenue reset, a

[8] In fact there is little evidence that demonstrates that where a non-network solution has been used, that there has been a resultant reduction in the overall reliability of a network

solution which reduces opex increases profit. As increased capex also rewards the NSP, there is no countervailing pressure on the NSP to find an opex solution for a network need.

The EBSS therefore creates a disincentive for DM by encouraging NSPs to exchange potential DM programs funded by opex for capex programs where profits are greater.

2.1.5 Assessment of BB

Assessment of the above four elements used by the regulator in the building block approach shows that there is potentially an in-built discrimination against demand management.

The first two elements – return of capital and capex forecasts – provide the NSP with its main profitability drivers and, therefore, incentivise capital programs. The obverse to this is that they dis-incentivise DM. This discrimination is further enhanced by the other two elements of incentive regulation (service performance and efficiency benefits schemes) which are intended to encourage the NSP to be economically efficient and improve service performance. However, a service performance scheme would tend to encourage network augmentations and capital upgrades under the guise of increased reliability, whilst an EBSS would tend to steer an NSP away from opex based solutions and, therefore, towards network solutions.

2.2 The revenue cap (RC)

When the allowed revenue has been decided (eg under a BB approach) a revenue cap form of regulated recovery of revenue requires the NSP to develop a set of tariffs which will return the allowed amount of revenue. These tariffs change from year to year to allow the NSP to recover only the allowed amount of revenue an NSP can recover. This therefore insulates the NSP from any variation in demand or consumption within the network. Because of this, except in through the derivation of the revenue included in the development of the BB approach, a revenue cap of itself does not incentivise or dis-incentivise the NSP to provide DM approaches.

If a demand management incentive program is to be introduced, then a revenue cap approach provides a neutral background for such a program to be implemented. Thus the form of revenue recovery is neutral to either DM or network solutions, even if the development of the allowed revenue might provide a bias against DM (as does the BB approach) in the way it assesses the amount of revenue that can be recovered.

2.3 The price cap (PC)

Once a revenue is determined under a price cap form of regulatory recovery, the NSP develops a set of tariffs which in theory will recover the allowed revenue based on the demand and consumption expected in the network over the regulatory period. If the demand and consumption vary then the NSP accepts the risk and/or benefits for such variation.

A price cap, therefore, provides an incentive mechanism for the NSP to **actively increase** demand and consumption in its network, as by doing so it will receive more revenue than was assumed in the regulatory reset. The NSP is permitted to retain this increase in revenue, effectively increasing its profitability.

Increased utilisation of the network (ie a higher load factor, and/or operating closer to the maximum capacity of the network) is the driver behind a price cap approach. Increased utilisation of the assets has the benefit of reducing the unit costs to consumers for using the network, but, if the increased usage results in higher usage at times when the network is near or at capacity, the approach will result in higher long-term infrastructure costs.

Demand management has a number of objectives, but principally these are to use less electricity and/or to improve the system load factor and/or to provide economically more efficient outcomes than by implementing network solutions. As noted in section 1, load factor can be improved by load shifting, self generation, and peak time demand reduction. Implicitly there are many benefits from an overall reduction in energy use which is also a focus of DM.

Self generation and peak time demand reduction have the overall effect of reducing network-based consumption, whilst load shifting does not reduce consumption.

Thus of the four primary actions that DM seeks (reduce consumption, peak time demand reduction, load shifting and self generation) only load shifting is considered to be neutral with regard to a price cap model as load shifting does not impact on the amount of electricity consumed, whereas the others all reduce the amount of electricity transported on the network, and an NSP would consider that these will reduce its revenue. A reduction in revenue (with its corollary a reduction in profitability) provides a strong disincentive on the NSP operating under a price cap regime to implement DM.

Therefore any approach which is likely to reduce the total amount of electricity carried on the network will be considered by an NSP to be against its commercial interests. Thus the only aspect on which a DM proponent and a price capped NSP are likely to concur would be where there is an increase in consumption during off peak times, such as might be achieved by load shifting.

A price cap incentivises the NSP to increase demand and consumption of electricity to raise its profitability, and to reduce unit costs to consumers, and is therefore a strong disincentive to DM.

2.4 Total Factor Productivity (TFP)

As a variation on using the BB approach to developing tariffs under a price cap, there has been a move in Victoria to simplify the regulatory approach using TFP to adjust the tariffs used by a network to recover their revenue.[9]

The simplicity of the TFP approach removes the detailed analysis of costs required under the BB approach. Effectively, the TFP approach assumes that the tariffs developed under a BB approach were efficient and, based on the comparative performance of similar NSPs, the agreed future tariffs will be adjusted annually using an average performance factor.

In theory, the TFP approach should drive the NSP to use the lowest cost solution to any network need, and would not discriminate between a DM solution and a network solution. The disadvantages for DM implicit in the BB approach are largely eliminated because:-

- The driver to use network solutions (as the NSP profit is embedded in the WACC applied to capital) is avoided
- The problems associated with the ex ante capex approach are removed
- There is no requirement for an EBSS, thereby eliminating this disincentive
- The incentive for network solutions under the service performance program are balanced by the incentive to use the lowest cost solution

Whilst TFP might appear to be supportive (or at least not unsupportive) of DM, the TFP approach is only applicable to a price cap regime, which is itself incentivised to increase demand and consumption, and which therefore negates most of the focus of DM and the approaches by which DM can be achieved.

A TFP program has a number of other disadvantages that need to be assessed in light of the overall goals of encouraging DM. In particular, it is not a tool

[9] TFP does not apply to revenue cap regulation.

which provides transparency and therefore might not provide the necessary transparency required to encourage DM options (and energy efficiency).[10]

2.5 Current NEM approaches to DM

2.5.1 The South Australian model

In 2005, the South Australian jurisdictional regulator (ESCoSA) developed its own approach to the lack of DM being undertaken by the SA distribution NSP (ETSA Utilities).

It determined that a number of specific DM actions could be trialled and recovered by ETSA up to the amount of $20 million. ESCoSA applied a number of constraints on ETSA, including the requirement that underspend of the $20 million would be returned to consumers.

ESCoSA also implemented some other close controls on ETSA when it stated that:

> "The Commission will closely monitor the outcomes of each demand management initiative. The Commission envisages establishing specific reporting requirements for each of the pilot programs. Table 4.1 outlines expected outcomes to be monitored for the major pilot programs.
>
> From the Commission's perspective, it is important that value is achieved from the programs that are funded. The programs suggested above have the potential to achieve positive returns for ETSA Utilities and the community. The Commission is committed to achieving progress in the area of demand management and will work with ETSA Utilities, consumer groups and the Government in the realisation of this potential."

The program that ESCoSA embarked on examined a number of aspects that it considered ETSA could properly develop value from, on behalf of consumers, and these were included in Table 4.1 of the Final Determination.

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[10] As noted in appendix 4, TFP has a number of other disadvantages that would need to be balanced against any positive aspects of TFP.

Table 4.1: Outcomes to be monitored for major demand management pilot programs

PILOT PROGRAM	OUTCOMES
Power factor correction	Improvements in power factors at customer installations; size of capacitors installed; cost of installing capacitors at each site; level of incentive payments; administrative costs.
Standby generation	Nature and cost of generator modifications; number of times that generators are used for network or system demand support; duration of support periods; kWh generated; peak load reduction outcomes; level of incentive payments; administrative costs.
Residential DLC	Details of the DLC system selected and reasons for that selection; details and costs of modifications to customer installations; cost components of the DLC system; number of customers involved; type and size of customer equipment controlled by the DLC system; times and duration that the system is used for network or system support; number of kW interrupted and the duration of interruptions; level of incentive payments; administrative costs.
Aggregation	The Commission will monitor ETSA Utilities performance in aggregating demand management resources within the NEM.

ESCoSA also considered the inclusion of aspects addressing critical peak pricing (a disincentive to consumption at times of peak demand), voluntary load control (where consumers decide whether they will reduce demand when network peaks are occurring) and interval metering (which allocates usage to time and the costs applicable at each time interval)[11]. For various reasons it considered that these should not be included in the current ETSA program.

Prior to this determination, ESCoSA reviewed many of the DM approaches used throughout the world, including the 'D-factor' scheme developed and implemented by the NSW jurisdictional regulator, the Independent Pricing and Regulatory Tribunal (IPART). ESCoSA observed in its reset of ETSA Utilities in 2005[12]: (page 58):-

> "Recent national reviews of the NEM have commented that there is significantly less demand response in the electricity market than might have been expected, given the price signals available in the market. These reviews have identified certain barriers to demand management in the electricity market, which include the fact that net margins and the length of the typical retail electricity contract preclude retailers from making significant investment in either time or equipment to facilitate demand management initiatives. **In addition, the disaggregation of what were once vertically integrated organisations into independent businesses makes it extremely difficult to realise all the benefits of demand management initiatives and hence to offset the costs involved"**. (Emphasis added)

[11] There is a wide acceptance that CPP, VLC and IM will reduce use at peak times, but they are seen to be more related to system needs (in the case of CPP and IM) rather than network needs, and VLC is seen as sufficiently uncertain by networks so as not to be accepted as sufficiently reliable to avoid network overloads.

[12] 2005 - 2010 Electricity Distribution Price Determination, Part A - Statement of Reasons, April 2005

ESCoSA also observed that:-

> "As a result there is relatively little demand management available in the market for any application – network augmentation deferral, energy market arbitrage, or ancillary services."

ESCoSA could have further concluded that the BB approach, with its built-in disincentives for DM, especially using the price cap form of regulation, was also a contributory factor in discouraging DM. To counter the disincentive that reduced electricity sales was likely to bring to the trial fund, ESCoSA introduced a 'correction factor' to reduce the financial risk to ETSA Utilities of reduced energy sales.

This approach is readily applicable in the BB approach and can apply to both revenue and price cap forms of regulation.

It is currently too early to ascertain to what degree the ESCoSA approach has led to the successful implementation of DM programs.

2.5.2 NSW's 'D-factor' approach to DM

NSW's IPART implemented a scheme prior to that of ESCoSA. In the NSW approach, IPART took a different approach to DM with its 'D-factor' scheme. Under this scheme, the NSP has a small incentive to implement DM, which includes the ability of the NSP to recover both the cost of the DM project and the revenue foregone due to reduced consumption. While the benefits of the DM that has been initiated under this regulatory incentive have been considerable, with a 3.8:1 benefit to cost ratio,[13] the total amount of DM delivered has been modest. The NSW distribution NSPs delivered peak demand reductions of 29.4 MVA in 2004/05 and a further 12.4 MVA in 2005/06, equivalent to about 7% and 3% respectively of the average annual growth in summer peak demand in NSW.[13]

As the ISF report for TEC concludes, the D-factor approach has been only a qualified success, with expenditure by the NSPs on D-factor DM being equivalent to only 0.13% of their revenue, one fifth the amount of average US utility spending on DM and even less compared to the leading US utilities.[13] The ISF concludes that for the D-factor approach to work, a range of complementary changes are also needed to compensate for other disincentives to DM. These recommendations are listed in Appendix 7.

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[13] Institute for Sustainable Futures for Total Environment Centre, *Win Win Win: review of the NSW D-factor and alternative mechanisms to encourage demand management*, Jan 2008, p. 6.

The Energy Markets Reform Forum concurs on the limitations of the D-factor approach. In its response the AER proposed NSW transitional guidelines[14] for distribution regulation it stated:

> "Unfortunately, the EMRF considers that there are much greater impediments to gaining the full benefits of DM than could ever be addressed by the D-factor scheme. …the EMRF does not support the implementation of the D-factor scheme as proposed as it would have to operate in an environment where the outcomes it is supposed to provide have too much opposition from other sources and it is unproven to provide sufficient benefit to consumers for the costs it imposes on them."

The EMRF recommended to the AER[15] that an approach as used by ESCoSA would have been a preferable approach to DM, as it provided its targeted program and was developed after ESCoSA reviewed the IPART D-factor scheme. The EMRF noted that:

> "A targeted scheme (like that used by ESCoSA) can be much more clearly benchmarked than the more indirect scheme like the D-factor scheme. The results of the ESCoSA scheme are available to all whereas the D-factor scheme does not lend itself to sharing the benefits learned by one DB with others. As the NSW/ACT region has four DBs, sharing experiences in a formal manner as the ESCoSA scheme does, has much to recommend it."

The D-factor approach is readily applicable in the BB approach and can apply to both revenue and price cap forms of regulation. However, in balance a targeted scheme, such as the ESCoSA approach, is more transparent and able to be more widely used than the D-factor scheme which has the focus of ensuring the DB remains financially whole, in that there is more focus on ensuring the NSP receives the full benefit of any lost revenue rather than a focus on the implementation of DM programs.

Using TFP will make this defined program approach less transparent (or even not occur), and as a result, require a parallel but separate approach similar to the service performance scheme to be implemented.

2.5.3 Disaggregation and split benefits

In addition to the disincentives to DM that emanate from the BB and price cap forms of regulation mentioned above, is the final problem of the disaggregation of the supply side elements of the electricity supply chain. This results in the benefits of DM having to be determined in relation to two or more elements – the overall system

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[14] Comments on the proposed [AER] Pricing Guidelines, December 2007
[15] Op cit

benefit and the network benefit, and as noted above, ESCoSA recognised this difficulty when developing its DM program.

By disaggregating the electricity supply chain, the benefits of DM are divided into two different markets, and when DM benefits for networks are considered in isolation from the system market (as is required by the network regulator), it faces considerable difficulty in demonstrating benefits specific to the network, whilst the benefits to the overall electricity market may be compelling.

2.6 Summary

The BB approach as used in the NEM is based on incentive regulation. The BB and the incentive regulatory approach both tend to incentivise network solutions and therefore disadvantage DM solutions.

Of the two forms of regulation for recovery of the allowed revenue (revenue cap and price cap) the revenue cap is indifferent to DM whereas, on balance, the price cap approach has an inbuilt disincentive for DM.

As an alternative to the BB approach, the use of TFP would seem to be indifferent to DM (not unlike the revenue cap approach). It is the concerns with other aspects of TFP that imply that TFP might not be in the overall interests of consumers and DM. In particular, TFP is applied under a price cap approach and therefore it suffers from the implicit disincentive that a price cap revenue recovery method has towards DM.

The outcomes of the two DM programs implemented in the NEM so far (in NSW and SA) have been inconclusive, and further review is needed. Both approaches are readily applicable in the BB approach and can apply to both revenue and price cap forms of regulation.

Using TFP will make the defined programs already in use less transparent (or even not occur), and as a result, might require a parallel but separate approach to DM similar to the service performance scheme to be implemented.

On balance, a targeted scheme like the ESCoSA approach for SA provides greater transparency than the NSW D-factor approach, although both approaches are readily applicable in the BB approach and can apply to both revenue and price cap forms of regulation.

Overall, the regulatory approach used in the NEM has not provided a strong focus on DM, and when this is combined with the inbuilt incentives for network solutions, it is not surprising that implementation of DM approaches have resulted in very modest outcomes.

3. What incentive schemes might deliver DM best under the current regulatory settings?

The second question sought in this review is what can be altered to improve DM under the various regulatory settings currently in place in the NEM[16].

To answer this question, each of the regulatory approaches used needs to be examined to determine what mechanisms are needed under each form of regulation to maximise the likelihood of networks to utilise the full potential of DM.

3.1 Compensating for the building block approach

As noted above, the building block approach has a natural bias towards implementing network solutions rather than alternative solutions (eg non-network support).

To avoid network solutions being implemented in preference to non-network solutions under the BB approach would require the business to carry out a rigorous examination of the options under regulatory oversight.[17] Further, the regulator would have to recognise that there are in-built biases towards network solutions in the BB model itself, the ex ante capex approach, the EBSS and the performance standards incentive schemes, and develop appropriate mechanisms to counter these. In particular, a holistic approach examining both system and network requirements, with DM as a primary objective, needs to be part of the regulatory reset and explicitly factored irrespective of the forms of regulation (price cap or revenue cap) adopted.

Such an approach will require the Rules to be modified to allow the regulator to:

- Reward the business for implementing a non-network solution which is included in opex (or to replace the profit lost by the business from not having a network solution)
- Open up the elements of the ex ante capex approach where a non-network solution might apply
- Segregate out of the opex EBSS all allowances relating to non-network solutions
- Address allegations that non-network solutions deliver lower performance by ensuring NSPs implement systems to identify if reliability has actually been

[16] At the second forum, a listing of specific questions was identified. These are included in appendix 8
[17] TEC has proposed a Rule change package that outlines some elements of such regulatory oversight. The AEMC is currently considering these proposals.

reduced by the implementation of DM solutions. If the allegation can be sustained, an alternative approach might be to require a two tiered approach to setting performance targets within the bonus/penalty arrangements.

- Require DM to be a separate and definable part of the BB development. This then provides the transparency necessary for all to see the costs and encouragement provided to engender the DM program.

3.2 Compensating for the price cap

As discussed in section 2 a revenue cap form of regulation on revenue recovery is neutral with regard to demand and consumption (and hence DM). It has been noted that many jurisdictions have reverted to a revenue cap (or basically similar) form of regulation so that DM programs are not negatively impacted

In jurisdictions where the price cap has been retained, the approach has been to allow the network business to be paid for the loss of revenue it incurs due to a DM option being implemented. This is the current approach under NSW's D-factor. This reduces the **dis**incentive inherent in the price cap approach, but still does not remove the incentive for rewards which come from increasing demand and consumption. In other words, while DM may not negatively affect revenue, increases in demand and consumption will definitely increase revenue, and therefore provides more certainty for networks.

The price cap approach, however, also lends itself to tariff manipulation, so that cost reflectivity of pricing, which is essential for economic efficiency, is lost along with the essential element for the efficient implementation of demand side responsiveness. If the prices for a service do not reflect the cost to provide the service then there will be an anomaly in the outcomes.

This issue has particular relevance as the network then has the ability to set prices which could prevent a reduction of consumption (to avoid a reduction in its revenue) and allow networks (both price capped and revenue capped) to implement network options in preference to other options for providing the service.

3.3 Capacity market versus energy only market

Eminent international economists[18] consider that an energy only market has an essential flaw in that it will not allow a generator to recover its long run marginal cost (LRMC)[19] and therefore cannot make an adequate return. This forces the generator

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[18] such as Jaskow of MIT and Tirole of University Toulouse. The views of these economists are denied by the proponents of the NEM.
[19] See glossary for a definition of LRMC

to exercise its market power or to undertake tacit collusion with other generators to create price spikes and so distort the market. Payment for providing capacity to be available in the market is a tool which both allows a generator to recover its LRMC and provides an incentive for new generation, including self generation.

In this regard it should be pointed out that government incentives to build renewable generation in the NEM under the MRET scheme actually provide a similar degree of certainty for a return that a capacity market does. Similarly, the incentive of paying feed in tariffs from micro generation is another form of capacity payment, especially if the feed in tariff is oversized (see appendix 9) to reflect the non-commercial benefits (eg. greenhouse, community) it provides the system market or network.

One of the key arguments provided by NSPs against non-network solutions is a view that they tend to be less reliable than network solutions. This may be a plausible argument when a non-network solution is considered in isolation or when the DM provided is demand side response (DSR) and aggregators are not required to carry the financial risks of failure to provide the agreed support.[20] However, where many non-network solutions are implemented then the aggregate of these will match (even exceed) the reliability of a network solution[21].

Thus in consideration of non-network solutions, the NSP should be required to asses the impact of having a number of non-network solutions as part of its required analysis of non-network solutions.

3.4 Economic Efficiency and the NEM Objective

The objective of the [National Electricity] Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

(a) price, quality, safety, reliability and security of supply of electricity; and
(b) the reliability, safety and security of the national electricity system.

Although the Objective makes reference to "…the efficient use of electricity…" as being part of the objective, the second reading speech introducing the Law

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[20] Which, for example, may result in providers accessing DM well in excess of what is actually required to ensure an adequate buffer.
[21] For example, in the case where there are many self generators, then the network assessment does recognise the network benefits afforded by the diversity of many such generators. This results in the paradigm that unless there are many concomitant self generators provided, then there is no assessed network benefit. The benefit comes from having a number of self generators but this never occurs because each self generator is assessed in isolation. This then becomes a "Catch 22" issue – until you have it you can't get it.

specifically identifies that 'use of electricity services will be efficient when services are supplied in the long run at least cost', and that efficiency should be read in terms of the electricity market economics, rather than in terms of technical efficiency of the electricity system.[22] Thus the Market Objective for the NEM is predicated on the premise that economic efficiency will provide the basis for the electricity market that "…is in the long term interests of consumers".

It is debateable whether the supply of services delivered on the basis of "economic efficiency" will automatically deliver efficiency in the use of electricity. In fact it has been noted that the overall thermal efficiency of generation in the NEM has fallen since the advent of deregulation[23]. What is clear, however, is that efficiency in the use of electricity is unlikely to be achieved if the above regulatory disincentives to DM remain, and without any external policy intervention to increase efficiency.

A number of consumer advocates have also pointed to an inadequacy of the implicit "economic efficiency driver" in the Law to deliver equitable outcomes for different classes of consumer (eg in regional areas where costs are higher, those with consumption patterns which are beyond their control to change, etc). Whilst these concerns have validity, they are not necessarily an issue for DM except where DM has the ability to reduce network costs due to those perhaps unique features applying to specific classes of consumer.

Economic efficiency in the NEM is already being distorted (including some measures introduced to meet social objectives) by:

- The impact of generator market power
- Tariff manipulation by the regulated businesses which returns a revenue above levels assessed by the regulators
- The Commonwealth government imposing a requirement on large energy consuming businesses to undertake programs to increase the efficiency of energy usage
- Governments mandating increased renewable generation which is a transfer of wealth from consumers to renewable generators in the short term in order to reduce long term carbon costs and the other economic impacts of climate change

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[22] National Electricity (South Australia) (New National Electricity Law) Amendment Bill, 9 February 2005.
[23] Bardak Ventures Pty Ltd, The Effect of Industry Structure on Generation Competition and End-User Prices in the National Electricity Market May 2nd 2005, page 55

- Governments mandating "feed in" tariffs for micro generation which require all electricity consumers to pay more than they would for conventional generation (see appendix 9)

- Governments introducing subsidies on energy bills for disadvantaged consumers

- Regulation that encourages inefficient infrastructure augmentation, such as the ex ante approach to capex, and the automatic roll in of actual capex, regardless of demonstrable optimisation

- Regulators allowing networks to recover costs incurred in the provision of demand management, as an incentive

- With the impending introduction of greenhouse gas emissions trading, the expectation is that the cost of electricity will increase, and that disadvantaged consumers will need to be protected as will manufacturing businesses exposed to imports from countries without equivalent greenhouse emission reduction obligations

- Subsidies for the production and consumption of fossil-fueled electricity generation, (eg R&D for carbon capture and storage technologies[24]).

These are just some examples of situations where economic efficiency is being distorted in order to achieve other objectives. It becomes an issue of the standpoint of the assessor of these distortions, as to which are considered "good" and which are considered "bad".

It has been noted that TEC and other NEM advocacy groups have repeatedly made the case that the NEM objective, which is currently focused on economic efficiency, should be supplemented by environmental and social sub-goals, as is the case in the UK and the New Zealand electricity markets.[25] It is argued by them that this would give regulators the scope to take into account these objectives when undertaking economic regulation. Proponents have stated that in the NEM there is a tendency to dampen some environmental and social policies initiated external to the

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[24] Institute for Sustainable Futures, *Energy and Transport Subsidies in Australia*, Chris Reidy, April 2007.

[25] For example: Total Environment Centre in consultation with Gilbert + Tobin, *How Should Environmental and Social Policies be Catered for as the Regulatory Framework for Electricity Becomes Increasingly National?*, November 2006; Total Environment Centre, Consumer Utilities Advocacy Centre, Business Council for Sustainable Energy, Australian Council of Social Services, WWF, Australian Conservation Foundation, St Vincent de Paul Society, *Power for the People Declaration,* May 2007; *The National Electricity Law Amendment Package*, (signed by 21 community organisations), August 2004.

NEM[26]. The recent MCE direction for the AEMC to review NEM barriers to emissions trading and the Mandatory Renewable Energy Target (MRET) scheme implies that the NEM is, in fact, porous to external policy programs.

It is a TEC contention that, rather than maintaining the NEM operation in isolation from broader energy policy, it is preferable that the National Electricity Law and Rules acknowledge their place at the centre of Australia's greenhouse emissions problem and work with, rather than against, external actions. Equally, if economic efficiency is to be removed as the basis for the National Electricity Law (NEL), then it is questionable as to what other basis could be used. Electricity is an essential service, and must therefore be available to all. When considered in this way, then the prime basis on which the current understanding of the objective should be based, is economic efficiency. This tension between economic efficiency and external environmental goals has to be resolved.

For some industry participants and some business consumers, the existence of the NEM has allowed them to argue against external policy instruments on the basis that the NEM provides sufficient price signals for energy efficiency. Nevertheless, the requirement to achieve economic efficiency has not detracted policy makers from applying other objectives affecting the electricity supply system. For example, the Energy Efficiency Opportunities Act requirements on large consumers, and the impending costs on emissions of carbon, are apposite examples. However because of the inelasticity of consumption, and the cost of electricity starts from a very low base of total disposable household income, the need for other instruments to encourage energy efficiency has come to the fore, as well as a need for the NEM to be more compatible with such policies. It is a distinct disadvantage to have key instruments in conflict with each other.

If the NEL objective remains unchanged, new goals (such as increased energy use efficiency, or an overall reduction in electricity consumption) would continue to be treated as a separate Law[27]. However, by requiring the NEL to continue to focus on the most economically efficient outcomes (in their narrow meaning), to the clear exclusion of the widely supported need for energy efficiency, is a serious concern.

However, if DM continues to be dis-incentivised by the regulatory framework, as outlined above, then it may be preferable to have DM explicitly encouraged external

[26] For example, despite the existence of the Mandatory Renewable Energy Target scheme, there remain major barriers to the connection of distributed generation to the monopoly networks; despite ongoing policy statements in support of DM, non-network solutions continue to be hampered in the NEM.
[27] For example, California mandates electricity use targets and requires that the CPUC implements a program within the regulatory approach applying to the regulated businesses to achieve the desired outcome

to the Law. This may be a better method of ensuring the target outcomes are realised, with minimal opportunity for gaming within the Law and Rule.

This imposition of external requirements on the core aspect of the NEM would replicate the approach used in California, an approach which is discussed more fully in section 5.1 below

3.5 Network issues and demand side response (DSR)

Network costs are currently driven by the need to provide for the maximum demand. This means that network revenue should be determined by the demand of each consumer, rather than the amount (consumption) of each consumer. Therefore, cost reflective pricing would imply that demand alone should be used as the basis for revenue recovery. By following such a practice, it would impose the cost of providing the network in proportion to the maximum demand each user makes of the network. When viewed from this position, network pricing on the basis of consumption is not cost reflective.

Long term demand is penalised by “ratcheting”. This is the process where a network business measures the single highest demand used in the previous twelve month period, and charges the consumer regardless if the demand is reduced in this period. This approach does not encourage DSR.

If a consumer has a demand which is used only occasionally and at times when the network has spare capacity, the network charges for use of the network as if the demand was continuous. This approach is based on the assumption that if the assets are available and used (even if occasionally) then the full cost should be recovered from that consumer.

In this regard the Rules would appear to be contradictory. In one part of the Chapter 6A Rules this view holds sway, yet in another part, the Chapter 6A Rules seem to imply that a consumer’s demand should be measured at times when the system is experiencing peak usage. Chapter 6 of the Rules for distribution networks is also similarly not clear.

The AER resolved this dichotomy in its transmission revenue guidelines, by allowing the regulated business to determine which approach they consider best suits their needs. This must be considered an abrogation of the responsibility of the regulator to enforce the Rules. If the regulator has a concern regarding the Rules, then it should seek to give direction as to what the Rules are intended to achieve.

It would appear from the Rules that if occasional use is made of the network, and at times when the system is not operating at peak demand, then occasional use of the network should be provided at a lesser cost. Such an approach would be significant in supporting DSR options because most DSR options are not "schedulable" and may need occasional support from the network. If that use is sufficiently infrequent and occurs at times of low usage of the network, then it is appropriate that the cost for the use of the network when it has available capacity could be provided at a discount, to reflect the usage pattern of the DSR option.

At first blush, such views would appear to be contradictory. On the one hand, even if only used occasionally a user should still pay full value for using the network. On the other hand, if used when system (and network) demand is low, why should there be a payment as if the network is used continuously? This dichotomy lies at the heart of DSR, especially self generation. If the DSR is scheduled not to be available (eg. is scheduled for maintenance) at times when there is not a need for the DSR (ie when the system demands are low), or alternatively put, it is available when there is a need for it, then both the needs of the DSR provider **and** the network provider can become coincident. It is not so much that the arguments are contradictory, but more about the **timing** when the DSR can provide the needed service by the network provider.

Thus an approach for incentivising acceptance of what is seen by NSPs as a less reliable DSR solution, might be based on the following:-

- For DSR to be provided on a capacity basis, and penalised if it is not provided when called upon (following the practice used for generation in an electricity capacity market)

- For demand to be measured and charged for in accordance with the peak demand registered in each billing period, which incentivises DSR to use the network only at times of low system demand

With such an approach DM should be treated as the benefit it is to the network.

3.6 Summary of potential to improve DM under the various regulatory settings currently in place in the NEM

There is no doubt that DM is being constrained by the regulatory approaches used, and when combined with the limited but under-powered (in economic terms) DM schemes in operation, the modest outcomes are not unexpected. It is difficult not to conclude that regulators have not given sufficient weight to DM measures.

There would appear to be no simple solution to overcoming the inherent disadvantages that the BB, TFP, RC and PC approaches impose in providing dis-incentives to DM. The most likely approach to be successful in the NEM is that used by the ESCoSA for its pilot program for DM, which provides a parallel program supervised by ESCoSA to bring about defined outcomes. But it is, nonetheless, a rather modest program, and it still does not address the essential element that DM is likely to reduce the revenue of a price capped NSP. The fact that a price cap provides an incentive to **increase** consumption (and hence revenue) is not addressed by the regulatory approach to compensate for revenue lost by the implementation of a DM program. The most obvious approach to address this problem is to implement a revenue cap which totally disassociates the NSP from the need for compensation for lost revenue, and eliminates the incentive to increase consumption as a means to increase revenue..

The ESCoSA scheme bears many similarities to the successful CPUC program used in California (which is discussed in section 5) but would need substantial modification to overcome the remaining deficiencies – the most obvious of which is that the CPUC scheme provides the mechanism to achieve the externally set policy objective of increasing energy efficiency.

4. Which approaches are best for consumers, especially vulnerable consumers?

The supply of electricity must be considered to be an essential service. Without electricity supplies most of the current day activities and accepted standards of living would not be possible. Thus the supply of electricity on a reliable basis must not only be made available, but it must be available on terms and prices which allow it to be accessible to all sectors of the community. It is not acceptable to price the supply of electricity at such a level and without discrimination that certain sectors of the community cannot afford it its use.

It is important that it be recognised that supplies of reliable electricity can be made available to the community at prices which are generally within the capacity of all to afford without the need for cross subsidies. Despite many advantages accruing from the disaggregation of electricity supply chain and the partial privatisation that ensued, unfortunately the current regulatory regime for electricity supplies does allow for publicly and privately owned businesses in the supply chain to use the current market structure to either increase profits for shareholders or to extract additional revenues from electricity users.

To make DM occur, however, it is essential that those who are prepared to provide a benefit to the system to reduce stress on it should be rewarded and those that use power when the system is stressed should provide that reimbursement. Under such an approach, the cost to all consumers is reduced if workable DM programs are introduced, as by doing so there will be a benefit to all consumers by minimising costs and improving reliability.

Thus the issue for vulnerable consumers is whether the implementation of a DM program is in their interests and if such a program will either increase their costs, reduce reliability or prevent them from using power when they need it? Further, if vulnerable consumers see that they can benefit from providing DSR, then they should be encouraged to do so, especially if this would reduce their average cost of power.

To ensure that vulnerable consumers are not disadvantaged requires the implementation of a DM program which acts to prevent the implementation of capacity increases in generation and networks which are used only for short periods (thereby reducing overall costs) but could also allow such consumers to participate and garner the rewards of providing for a DSR program which acts to achieve these outcomes. Allowing disadvantaged and vulnerable consumers easy access to implement a DSR should allow them to reap full value from it, and so reduce their overall cost of the electricity supply service.

The ISF report notes with regard to the D-factor incentive, it allows networks to recover from consumers' revenue forgone by reduced electricity sales:

> "In principle, the D-factor will always benefit consumers because, in the short term, the price increase due to the Distributor's recovered lost revenue is much lower than the retail price of electricity saved by the consumer, and in the longer term, the cost of the DM measure is lower than the network costs avoided. In addition, the D-factor encourages energy savings that avoid both the environmental costs associated with greenhouse gas emissions and the financial costs associated with adapting to and offsetting these emissions."[28]

A DM program which results in using the lower of costs for a network solution versus a DM solution, should result in lower costs overall and all consumers should benefit.

4.1 Network service performance

Network service performance is measured and rewarded regardless of whether a BB or TFP approach is used or if a revenue or price cap revenue recovery mechanism is applied. Performance is measured across the entire network's performance and applied as a penalty/bonus scheme in parallel to the main revenue setting approach. This means that networks average out the poorly performing feeders with those of high performance feeders. As a result, the network does not have sufficient incentive to address the needs of consumers on poorly performing feeders[29].

In some cases, the consumer might get a small payment from the customer service performance arrangement. Unfortunately, this payment bears no relationship to the costs a consumer might incur.

Network tariffs use a combination of demand and consumption elements, so loss of supply on poor performing feeders is in part recognised by consumers not having to pay for consumption that they might otherwise have had to pay for and therefore the DB gets a lesser revenue.

In the case of payments for the demand element of the tariff, the network is still paid even if the service is interrupted.

Despite the service performance program being separate to the main revenue setting approach, it is only by actual performance that consumers can identify that

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[28] Institute for Sustainable Futures for Total Environment Centre, *Win Win Win: review of the NSW D-factor and alternative mechanisms to encourage demand management*, Jan 2008, p. 5.
[29] ESCV has introduced performance measures on a feeder basis but this approach has not been implemented in other regions of the NEM.

they are being provided with their half of the regulatory bargain – the regulatory bargain is that consumers will get a defined service for an agreed amount of money.

Service performance results from a number of issues – some of which are within the control of the NSP (such as meeting timeframes for maintenance and implementing replacement early enough not to lose a network element through using equipment that is too old) and others with are exogenous (such as weather conditions, demands from consumers, generator failures). Despite not being able to control all elements which lead to service performance, the NSP is rewarded or penalised regardless.

One of the main concerns about the service performance measures concerns a reduction of performance that is within the power of the NSP. This could stem from a deliberate program of not investing in capex or not spending opex as allowed as it will show up as poor performance only well after the actions are taken. For example, lack of opex and capital investment might not show up for a number of years after this deficiency was detected.

To assess whether a NSP might deliberately not invest opex and capex needs an understanding of the way any business operates in the current business climate. Businesses are assessed for financial performance on a quarterly basis by their investors, and after 12 months clear impressions are drawn[30]. After between 2 and 3 years investors will take action regarding their investments and if the financial performance is deemed to be lacking investors will sell down their shareholdings and seek better performing businesses to invest in. Thus short-termism in investing in businesses has created a 2-3 year window of performance.

Senior management of NSPs are being rewarded by share options which require a financial performance hurdle for them to be exercised. The concept behind this is to incentivise management to look to the interests of shareholders. Thus management is also committed to short-term rewards. This incentive on management runs counter to the interests of network customers who are affected by a much longer term view of performance.

Business incentives act as a dis-incentive to achieving long term service performance of the network. This is compounded in practice by the rewards for service performance limited by the regulatory guideline (AER) to 1% of allowed revenue, although the Rules (AEMC) allow this constraint to be as high as 5%.

[30] Although the investment outlook for government-owned utilities might not be the same as for privately owned utilities, nevertheless, short-term revenue gains are also a priority for such government owners.

Using such a low powered service incentive does not overcome the business financial performance incentive which would show much higher reward for reducing capex and opex.

To overcome the disparity of incentives, the service performance incentive should equal the business incentive. To achieve this, the 1% constraint against revenue must be increased. One way of doing so would be to require the NSP to pay consumers in equal measure if there is a failure of supply.

Ideally, such a penalty would require the business to pay the consumer the same amount that the consumer has to pay if supply had been provided. As the network tariffs have a mix of fixed payments (a payment related to the level of demand and a payment related to that amount of consumption) it would seem appropriate that the network would pay to all consumers an amount using the same bases (ie as if the supply had not been interrupted) for the entire billing cycle, including the ratcheting effect on demand.

4.2 Demand response for reserve trader

The NEM has the ability to ensure system security by the use of “Reserve Trader” powers. Reserve Trader is where the NEM operator (NEMMCo) directly contracts with suppliers in order to secure additional generation. As part of Reserve Trader, NEMMCo also contracts with end users to reduce their demand at critical times when asked to by NEMMCo.

When NEMMCo identifies that Reserve Trader is necessary, it calls for both increased generation (usually from generation that is not committed to the electricity market) and for consumers to reduce their demand when called on to do so. Reserve Trader has been initiated three times in the NEM (although it has not been called upon). NEMMCo have identified that the cost of Reserve Trader has been based on a mix of capacity payments and energy payments. Even though the Reserve Trader has not been dispatched, consumers have been required to pay for the capacity payments that were contracted for.

Although the cost for providing this demand side responsiveness is higher than the normal cost of generation in the short term, in the long term augmentation costs are reduced, making the DM option potentially more cost-effective than supply.

Consumers do not necessarily consider that their electricity supplies are seen in isolation – they also consider the impact of **not** being supplied. Whether a consumer is a business or a residential consumer, the loss of amenity can be considerable. If a consumer elects to reduce demand (ie lose its amenity) then it needs to place a value on this loss. Whilst it is relatively easy to value the loss of amenity in a business context, this must not cloud the view that loss of amenity in a residential context has no value.

Whilst not being readily quantifiable as each consumer has its own cost structure for offering a DM response, DM is likely to cost more than conventional supply methods.

Providing that there is a balanced approach to costing both options (and this is discussed in sections above), then even though both options will increase costs, a DM option might cost less. When this occurs the party offering the DM will receive a benefit. While all other consumers will be required to pay more for the service, the costs of infrastructure augmentation will be less in the long term.

Providing the concept of economic efficiency has been applied, consumers will receive the optimum outcome from whether a DM or a network approach has been used.

Thus demand side management should not impose a cost premium on consumers.

4.3 System security

The supply of electricity is now an essential service. Although some consumers can tolerate loss of supply for short periods, the loss of supply for extended periods can be devastating – the loss of refrigeration is an example of this type of supply loss. Some consumers, once having lost supply can manage for many hours without resumption of supply.

The timing of the loss is also influential. Loss of supply during the early hours of a morning for a short period is unlikely to have a major impact on a domestic consumer, but loss of supply during a meal preparation is critical.

As discussed above, there are some that consider that a network solution will provide the greatest reliability of supply. The issue that must be addressed is at what cost point is a less reliable but lower cost option preferable to a highly reliable but higher cost supply option.

This issue is not necessarily one of DM solution versus network solution but the degree to which one will provide a benefit over the other, and the cost to achieve the marginal gain. In fact, in many cases the overall difference in reliability between options might be negligible or one option might increase reliability by a relatively insignificant amount. What is essential is that in assessing an option both the change in reliability and the cost need to be assessed, so that a high but perhaps unnecessary cost premium for achieving a modest reliability benefit is not automatically accepted without assessing the cost to achieve that modest increase.

Effectively, such an approach requires the placing of a value on the relative changes in reliability. Thus it is essential that the increase in reliability is assessed against the cost of providing that increase.

Consumers do want a high security for their electricity supplies, but are prepared to accept less than 100% reliability because the economic cost of achieving 100% reliability can be too high. All options for network development should seek to balance the cost of the augmentation against the level of reliability that can be achieved for the cost.

4.4 Costs incurred by consumers in attempting DM

Some consumers have attempted to implement their own DM by investing in approaches to reduce overall demand and consumption. Of these the most well known is the implementation of residential energy efficiency ratings and the energy rating efficiency for household appliances.

Large energy consuming businesses are required to assess and report on, but not necessarily implement, energy efficiency programs under the Commonwealth government's Energy Efficiency Opportunities Act.

Consumers do incur costs as a result of these programs but the requirements for this energy efficiency are exogenous to the regulatory approaches used for assessing network businesses, even though they do have an impact on the networks.

Improving national energy efficiency is a goal which is to the benefit of the nation as a whole, and, while laudable, it is not an aspect which is related to the benefits DM can provided to networks, and the costs consumers should carry as part of the regulatory bargain with the network businesses.

4.5 Conclusions on aspects of benefits for consumers

The regulatory bargain requires a reasonable payment for the provision of a reasonable service. If a network is to be incentivised to provide a better level of service, then the incentive needs to match the business financial incentives to seek short term financial gains. The current low powered service performance incentive program does not match the higher powered incentives on a business to take short term gains.

If a consumer loses supply, part of the service performance penalty should be to pay the consumer what the consumer would be expected to pay the NSP, using the same tariffs and ratcheting approaches. After all, why should a consumer have to pay a fixed and demand charge regardless of whether they receive supply or not?

Provided the mechanism for assessing a DM approach from a network solution is made on economic efficiency grounds, then consumers are not worse off from having a DM solution, provided that this does not result is a lesser reliability of supply when compared to the costs for providing that higher reliability.

5. Which overseas DM incentive schemes deliver better outcomes?

The introduction of DM incentive schemes has been a vexed question for a number of reasons. The most critical is that by disaggregating the retail, networks and generation functions, this creates artificial barriers to giving full value to DM.[31]

A number of overseas DM programs specifically targeting incentives to networks would appear to be based on a revenue cap (or its near equivalent cost-of-service) approach, combined with reimbursement of the distribution business for lost revenue.

Our international colleagues, EEE, make the point that DM is not successful in many disaggregated systems, and has marginal success in many aggregated systems. The key point is that DM has not been the focus in many jurisdictions.

5.1 California

The TEC sponsored forum on 19 May 2008 was addressed by the Chairman of the California Public Utilities Commission (CPUC), who drew attention to the successful demand management program in California. The Californian State Government, through its utility regulator the CPUC, has introduced a strong incentive program for energy efficiency and demand management, and this program has been operating successfully for a number of years.

The CPUC regulatory approach is based on a number of significant differences from that used in the NEM, and these need to be fully understood. Notwithstanding this note of caution, these differences do not necessarily make the CPUC program unable to be introduced into the NEM, subject to appropriate policy and regulatory adjustments.

The CPUC program is based on the following elements:

1. The Californian government has mandated that the energy Utilities must provide a demand management program with set goals to be achieved within a fixed time

2. The Utilities the CPUC supervises provide a “fully bundled” service from vertically integrated utilities which comprises energy, transport and retail functions, thereby enabling an integrated approach for DM

3. The Utilities operate on a cost of service (CoS)[32] basis rather than the incentive regulatory approach used in Australia

[31] See the ESCoSA comment included in section 2.5 above
[32] See glossary

The CPUC program is based around a legislated defined target of very specific outcomes concerning the goals of reducing consumption and incentivising energy efficiency, DSR and renewable energy. Demand management is one of the mechanisms that is used to achieve these goals.

Each Utility proposes an energy efficiency (with a DM component) and renewable generation program and requests an amount of funds for its implementation to be added to the revenue set from the cost of service (CoS) regulatory approach used in California. The CPUC assesses the funds requested and the program proposed. It then fixes the amount to be included within the approved tariffs of the Utility, and for the approved amount the Utility must deliver the outcomes proposed in the program. This program is to meet the longer terms goals legislated by the Californian government.

In turn, the approved CoS revenue is converted into approved tariffs. Thus embedded in the tariffs used by consumers, is an amount of money specifically targeted to provide increases in energy efficiency (and the DM program) and renewable generation.

The programs included by the Utility are wide ranging and encompass the impact on generation needs, increases in renewable energy supplies, network optimisation and overall reductions in energy use.

To encourage the Utility to meet the agreed outcomes, the CPUC has recently introduced an incentive reward program and appendix 7 provides some detail.[33]

The incentive program operates as follows:-

- There is agreement of the energy savings goal to be achieved and an agreed cost to achieve these savings

- These savings after the costs are deducted are assessed as a net benefit to consumers

- If less than 65% of the energy savings goal is achieved then the utility incurs a financial penalty

- If the energy savings goal achievement is greater than 65% but less than 85%, there is no penalty, but no bonus

[33] Full details of the program are included in CPUC document "Rulemaking 06-04-010 (Filed April 13, 2006)" and titled Interim Opinion on Phase 1 Issues: Shareholder Risk/Reward Incentive Mechanism for Energy Efficiency Programs.

- If the energy savings goal achieved is greater then 85% but less than 100%, the Utility is paid a bonus which is 9% of the net benefit that would accrue to consumers from the energy saving

- If the energy savings goal achieved is greater than 100%, the Utility is paid a bonus which is 12% of the net benefit that would accrue to consumers from the energy saving

This program operates across the entire operation of the Utility and so allows the Utility to accrue benefits from each element of its activities. Such an approach is significantly weakened under the disaggregated approach used in the NEM. It should also be noted that the program addresses much more than DM, as it incorporates the renewable energy program and energy efficiency goals, which includes consumer efficiency and network efficiency. Notwithstanding these observations, it is possible that such an approach could be tailored to incentivise NSPs to improve network and consumer efficiency within the NEM.

As a precursor to developing such a program for the NEM, it would require:-

- The mandating by government of an agreed level of efficiency improvement to be achieved

- The mandating of the AER to incorporate in its networks decisions, the costs for achieving these mandated goals

- A decision to discard the price cap approach in order to eliminate the need to reimburse an NSP for loss of revenue incurred as a result of implementing the DM response to improve efficiency levels[34]

Because, in the NEM, the renewable generation target is separately mandated and proportionate reductions in net generation are separately measured (and managed by retailers), incorporation of such goals is not required for the NEM at the current time. However, to convert the CPUC program to apply to network regulation is made quite difficult due to the disaggregation of the supply chain in the NEM and the inability to recognise the aggregated benefits of DM to the supply chain, although it is not impossible to assign targets to each disaggregated sector.

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[34] Retention of a price cap will require a mechanism to assess the revenue lost due to implementation of the program apart from the loss of revenue from other sources, and to overcome the incentive to increase demand and consumption implicit in the price cap revenue recovery. This is the current arrangement under NSW's D-factor regulation under a price cap. A revenue cap approach does not have this need to recompense revenue loss.

5.2 Other overseas approaches to network support of DM

EEE identifies that all networks operating with a price cap approach suffer from the need to increase power flow so as to ensure recovery of the needed revenue, and as a result a price control methodology is replaced with a revenue control approach. The **Massachusetts DPU** addresses this issue specifically, and keeps businesses "financially whole" due to the imposition of the DM program. As with the California example, the Massachusetts program applies to a cost-or-service model of tariff setting.

Con Edison, which is an integrated utility operating in New York State provides another approach. As with the California program established by the CPUC, there is a defined target established for Con Edison to reduce demand in its area. It is compensated for the costs it incurs from the lost revenue and is paid a fixed amount for each MW of demand is reduced, up to a cap, as an incentive.

The **Commerce Commission in NZ** applies a different approach to DM by using the allocative mechanism for transmission into distribution, by imposing a greater risk on the DNSP for recovering the transmission charges it has to pay for, but without it being able to pass through these onto consumers as applies in the NEM.

5.3 Conclusions on overseas DM incentive schemes

DM has been implemented in a number of overseas jurisdictions although more so in the US than in Europe. The impediment faced with using the US models in the NEM revolve around the need to mandate energy efficiency targets and the different structures (integrated in the US, disaggregated in the NEM) that apply.

The implementation of <u>DM approaches within network businesses</u> has not received much attention in overseas jurisdictions and thus the DM approach implemented by ESCoSA might be considered to be leading in this respect.

Consideration needs to be given to combining mandated energy efficiency targets in the NEM with the DM measures currently implemented by ESCoSA and by the CPUC, to drive a more powerful DM approach in the NEM.

6. What approach best meets the intent of the Rules

What mechanism best delivers the new revenue and pricing principles

a. *"A network should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in its operations"*
b. *"A network should be given effective incentives to promote the economically efficient investment in and provision and use of network services"*
c. *"The regulator must have regard to the regulatory asset base adopted in previous determinations"*
d. *"The prices and charges for regulated services allow for a return commensurate with the regulatory and commercial risks involved in providing the services"*
e. *"That the regulator has regard to the economic costs and risks of the potential for under or over investment by a network in its network"*
f. *"The regulator has regard to the economic costs and risks of the potential for under or over utilisation of a service provider's network"*

The following subsections provide comments against each of the principles raised.

6.1 Revenue and Price caps

Both a revenue cap and a price cap approach meet the requirements of the Rules, and are permitted for use by the Rules.

Rule element	Revenue cap	Price cap
A network should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in its operations	Provides exactly what the regulator determines are efficient costs	Exposes the business to over or under recovery of efficient costs related to actual demand and consumption
A network should be given effective incentives to promote the economically efficient investment in and provision and use of network services	Separate incentive programs are required	Separate programs are required, although the NSP is incentivised to increase demand

		and consumption, in theory so as to increase utilisation of the network
The regulator must have regard to the regulatory asset base adopted in previous determinations	Not impacted	Not impacted
The prices and charges for regulated services allow for a return commensurate with the regulatory and commercial risks involved in providing the services	Provides exactly what the regulator determines is an appropriate return	Incentivises the NSP to increase demand and consumption so as to maximise the return
That the regulator has regard to the economic costs and risks of the potential for under or over investment by a network in its network	The regulatory approach (including the EBSS) incentivises the NSP to under invest in the network	The regulatory approach (including the EBSS) incentivises the NSP to under invest in the network
The regulator has regard to the economic costs and risks of the potential for under or over utilisation of a service provider's network	Provides no incentive to increase utilisation, and provides no penalty for under utilisation	Provides an incentive to increase utilisation, and a penalty for under utilisation

6.2 BB and TFP

Only the BB approach complies with the Rules, although a Rule change is proposed to allow TFP to be utilised in the future

Rule element	BB	TFP
A network should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in its operations	The BB approach provides certainty of this	There is no certainty that this will occur
A network should be given effective incentives to promote the economically efficient investment in and provision and use of network	Provided	Not certain. The TFP **assumes** this has occurred and that the annual adjustments will

services		retain this feature
The regulator must have regard to the regulatory asset base adopted in previous determinations	Provided	Not necessary
The prices and charges for regulated services allow for a return commensurate with the regulatory and commercial risks involved in providing the services	Provided	The TFP approach does not ensure that this will occur
That the regulator has regard to the economic costs and risks of the potential for under or over investment by a network in its network	Provided	The TFP approach does not ensure that this will occur
The regulator has regard to the economic costs and risks of the potential for under or over utilisation of a service provider's network	Provided	Provides an incentive to increase utilisation, and a penalty for under utilisation via the price cap. There is a risk that the TFP approach (being less transparent) will incentivise less opex and capex – see timing risk under section 4.3

6.3 Summary

The Building Block and revenue and price caps are written into the Rules as forms of regulation, and therefore are considered to comply with the Rules.

Analysis of the TFP approach under the six regulatory principles, would indicate that a number of the Rule provisions would have to be modified to allow the use of TFP.

7. Forum conclusions and recommendations

7.1 The Forum Outcomes

The TEC convened a second forum to analyse the issues raised at the first forum and, in the brief to consultants, to provide some guidance for the development of this report. As previously noted, the report is to inform and provide guidance to TEC and the participating groups. Arising from that forum, the Final Recommendations for Consultants on Further Research and Report are noted as follows:

1. Explore external incentives for DM, in particular, the California dead-band targets

2. Explore options for decoupling revenue from consumption

3. High initial service standards are important

4. Needs to include holistic assessment (relative to values outlined above) of bottom line impacts

5. Identify what a network can or can't do well

6. Information on how overseas jurisdictions have used TFP

7. What is essential for TFP to work

8. How do consumers engage with TFP before and after its implementation

This report has provided responses to each of the above aspects, and the following observations are derived from the body of the report.

7.1.1 Explore external incentives for DM, in particular, the California dead-band targets

The analysis identifies that the current mechanisms used in the NEM for regulating networks have, either implicitly or explicitly, dis-incentivised NSPs from implementing DM. Effectively, ESCoSA had reached the same conclusion and consequently implemented a separate pilot scheme to determine actual benefits that can be derived by an NSP from certain DM activities. The Californian scheme is a high-powered DM scheme, which is greatly strengthened by related explicit Government policy targets for achievement of energy efficiency by electricity businesses.

7.1.2 Explore options for decoupling revenue from consumption

The earlier analysis identified that revenue can only be de-coupled from consumption by the implementation of a revenue cap approach, or by a separate mechanism that reimburses an NSP for revenue lost as a result of the implementation of DM.

In California, the successful DM programs have been developed in an environment of a cost-of-service model, which has many features (e.g. the build-up of capex and opex costs) akin to the revenue cap approach.

7.1.3 High initial service standards are important

Service standards are an important element of a regulatory regime as this provides the balancing half of the regulatory bargain – the NSP provides a service to the standards explicitly stated, for the amount paid by consumers.

However, care is needed in this aspect in regard to DM, as many DM options are considered by NSPs to provide lower availability than network options. As a result, imposition of very high service standards could result in less DM, for marginal improvement of service performance that a network solution might provide.

7.1.4 Needs to include holistic assessment (relative to values outlined above) of bottom line impacts

In the disaggregated system used in the NEM, holistic approaches to energy efficiency and DM are difficult. For example, the regulator only reviews network businesses, and not the contestable areas of generation and retail. As a result, many of the DM approaches used elsewhere in the world (such as where electricity systems are not disaggregated) are not readily convertible to the NEM environment.

ESCoSA observed this in its 2005 determination on ETSA Utilities and approached the implementation of DM from a different angle. It is expected that in 2009 when the next regulatory review of ETSA Utilities is commenced, a better idea will be available of what can be realistically included within the network to encourage DM.

7.1.5 Identify what a network can or can't do well

ESCoSA has probably made the most in depth study of this aspect in the NEM, and from this determined that it would require ETSA Utilities, in the DM scheme, to focus on only four aspects – power factor correction, use of standby generation, residential direct load control and DSR aggregation[35].

Of these, aggregation is arguably an aspect that might be one that the retailing function should manage, as retailers have the ability to aggregate demand from consumers in more than one distribution area. In the SA region of the NEM (as distinct from every other region), ETSA Utilities is the sole distribution business and therefore can act as an aggregator.

ESCoSA decided that for various reasons, critical peak pricing, voluntary load control and interval metering were not appropriate to be included in the ETSA program[36].

7.1.6 Information on how overseas jurisdictions have used TFP

TFP appears not to have been widely used in overseas jurisdictions. Where it has, it would appear that the sheer numbers of networks to be reviewed by the regulator predicated the need to implement such an approach (eg as in Germany).

Using a TFP approach might incentivise a network to use DM if a DM approach is the lowest cost option. Balancing this is that DM might not be perceived as reliable as a network solution, therefore causing the NSP to consider the risk of not meeting service standards.

When service performance is incentivised under a “low powered” program”[37] such as the AER currently uses, it is more likely that, under a TFP approach, the lowest cost option for network management might be implemented, regardless of whether this is a DM option or not.

7.1.7 What is essential for TFP to work?

A TFP approach needs:

- A price cap approach to tariff setting which creates an incentive to increase demand and consumption

- Accurate and detailed data over a reasonable length of time to provide confidence in the data set

[35] These are discussed in some depth in section 2.5
[36] The reasons for ESCoSA not including these are discussed in section 2.5
[37] See discussion in section 4, particularly section 4.1

- Certainty that the starting point tariffs are correct, both from a fundamental value basis and that they are cost reflective

- Sufficient numbers of participants to ensure that collusion (passive and active) is not possible

- Similarity between the NSPs being regulated to ensure that no one NSP might be treated inappropriately

There is a residual concern that if TFP reduces the profit of an NSP, or that a "bow wave" capex program[38] is required, then the outcome for consumers might be a reduced service. EEE makes this observation in appendix 5.

7.1.8 How do consumers engage with TFP before and after its implementation?

Consumers have almost no input into the setting of tariffs under a TFP approach. The data is collected and analysed by the regulator and an annual adjustment of existing tariffs is made by the regulator.

A TFP approach is essentially a mechanical approach to tariff setting.

7.2 Other incentives and mechanisms

There are concepts for encouraging DM that are being implemented in various overseas jurisdictions. It would appear that the most successful require a number of pre-conditions which include:-

1. A mandated outcome of energy efficiency targets (which includes DM) as a subset) around which the regulator can construct a program

2. A vertically integrated Utility which has the ability to capture the combined effects of DM rather than the disaggregated model used in the NEM which effectively disperses the benefits of DM to different elements of the NEM structure, and makes the benefits of DM in any one structural element marginal

3. A strong incentive on the Utility to achieve the agreed outcomes, with penalties for sub performance

[38] See glossary

Whilst precondition 3 is achievable in the NEM at this time, action is required to implement precondition 1, and this is currently a policy issue until or unless the regulatory framework is altered to ensure regulators take on this responsibility.

The achievement of the benefits from precondition 2 will not be possible within the current NEM structure (although it is not impossible to assign targets to each disaggregated sector), but ESCoSA would have appeared to provide an option which has the potential for a longer term and successful approach to the provision of DM.

7.3 Conclusions

Under the current arrangements, there is a disincentive to DM using the Building Block approach, and this is further reinforced when the BB is combined with a price cap (as opposed to a revenue cap) model, as it encourages consumption and demand.

The BB approach, through the capex and WACC mechanisms incentivises the network business to seek network solutions as these raise its profitability. On the other hand, a BB approach is very transparent and allows implementation of concurrent programs such as a specifically targeted DM program.

A TFP approach has the potential to be neutral in relation to DM (as, in principle, it incentivises the lowest cost option to maintaining the service) but as it requires the use of a price cap approach (which incentivises greater demand and consumption) using a TFP approach has certain constraints with regard to reducing the amount of power used overall (the focus of energy efficiency, and therefore of some DM aspects which might be considered to be a subset of energy efficiency).

A TFP program has a number of other disadvantages that need to be assessed in light of the overall goals of encouraging DM. In particular, it is not a tool which provides transparency and therefore might not provide the necessary transparency required to encourage DM options (and energy efficiency).

Using a price cap approach with a DM program requires an ability on the part of the regulator to identify any revenue lost to the NSP from a DM program and to implement a program to allow the NSP to recover this lost revenue. Such an approach has the potential to increase the “gaming” an NSP might undertake to maximise its revenue stream.

A revenue cap approach suffers from the inherent dis-incentives in a BB approach to DM, but as the BB approach allows transparency and for programs to operate in parallel, a BB approach combined with a revenue cap provides a “least worst” outcome for implementing a DM program which has some prospect of real success.

7.4 Recommendations

Under the current arrangements, attempting to implement a regulatory regime in the NEM to encourage DM (or even to provide neutrality) is challenging, due to the loss of synergies from vertical integration.

The BB approach provides built-in incentives to expand network investments, and, indirectly, increase consumption and demand. Consumers, however, should seek to engage in regulatory reviews and contest network businesses' capex and WACC claims.

A price cap form of regulation under the BB approach encourages the network businesses to increase consumption and demand. Consumers should seek to engage in regulatory reviews to contest network businesses' claims with respect to pricing methodologies and cost allocations, especially to ensure cost reflective pricing e.g. pricing based on demand and not on consumption.

Separate and parallel DM incentive schemes are the most effective way of ensuring DM initiatives by network businesses, especially when supported by policy directives to achieve stipulated targets of energy efficiency. Consumers should focus on ensuring that the schemes are high-powered and that regulators take a holistic view of the various pull and push factors that encourage/discourage DM outcomes to ensure there are real net DM outcomes.

Of the approaches examined in the NEM, it appears that the program initiated by ESCoSA has the greater potential for achieving the maximum benefit from DM for consumers. The ESCoSA approach is a parallel program to the standard BB approach to regulation.

To avoid the inevitable tension that a price cap approach brings, it is recommended that a revenue cap approach would assist by removing the incentive to increase demand and consumption.

To overcome some of the disincentives inherent in the BB approach (even with a revenue cap), it is recommended that a DM program be developed for each NSP and implemented as part of the NSP revenue reset.

A DM program might exhibit the following features:-

- It would operate as a parallel program as part of the regulatory reset

- The NSP would identify those DM actions where it could deliver a benefit to consumers

- An agreed series of actions and target outcomes would be established between the regulator and the NSP

- A fixed amount of funding would be included in the allowed revenue for the NSP to achieve these outcomes

- There would have to be a program of benefit sharing (such as that used by CPUC) of sufficient “power” to overcome the dis-incentives inherent in the BB approach, with penalties for sub performance

The DM program could be even more effective if it were driven by an over-arching energy policy requirement for achieving energy efficiency targets across the electricity supply chain.

APPENDIX 1

The Building Block approach

An economic regulator, such as the Australian Energy Regulator (AER), has the task of deciding how much cash a regulated business should be allowed to have each year to provide the service consumers want. Typically, the regulator will assess the cash needs of the business for the next five years and this is called the regulatory period.

In the Building Block approach, the regulator looks at each separate cost element of the business, and decides how much each part should cost each year. The regulator then adds up the costs for each element and the addition provides the allowed revenue for each year. This becomes the amount the business will be permitted to get consumers to pay through the tariffs set.

In a typical decision by a regulator, the regulator will look at the following cost elements.

- What is the value of the assets needed to provide the service now. This is called the start regulatory asset base (start RAB)
- What is a reasonable return for a business providing these assets to deliver the service. The regulator develops what is called the weighted average cost of capital (WACC) which will provide a reasonable rate of return on the cost of the assets needed to provide the service.
- How much was spent on new assets in the last regulatory period. This is called the past capital expenditure (past capex)
- What new assets need to be provided to replace worn out assets over the regulatory period, and to manage any expected increase in usage for the regulatory period. This is called the capital expenditure (capex)
- What will it cost to keep the assets in good working order over the regulatory period, and to ensure the assets provide the service. This is called the operating expenditure (opex)
- What was the difference between the allowed opex for the past period and the actual opex used. This provides the basis for the efficiency benefit sharing scheme.
- What was the loss in value of the assets as they aged over the past regulatory period. This is called the past depreciation.
- What will be the loss in value of the assets as they age over the regulatory period. This is called the new depreciation.
- What was the increase in costs due to inflation. CPI is most commonly used to value this.

- What is the likely increase in costs due to inflation over the regulatory period.
- How much better will the regulated business perform given some new assets and using improved techniques. This is called the efficiency improvement.

The regulator then carries out a series of calculations:

Calculation 1 - the value of assets at the start of the new regulatory period

Start RAB = RAB at the start of the old regulatory period + past capex - old depreciation

Calculation 2 – what is the RAB at the start of each year

RAB end year 1 = start RAB + start RAB*CPI + year1 capex – year1 depreciation

Calculation 3 – average RAB

Average RAB year 1 = (Start RAB + RAB end year 1)/2

Calculation 4 – return on capital

Return **on** capital = average RAB*WACC

Calculation 5 – valuing efficient opex

Efficient opex = assessed opex – efficiency improvement

Calculation 6 – smoothing the allowed revenue for each year

The "smoothing" is achieved by assessing amounts of equal change over the period which have the same net present value of the actual amounts calculated.

The building block for year 1

Cash allowed for year 1 =
average RAB*WACC
+ average capex year 1*WACC
- average depreciation year 1*WACC
+ efficient opex year 1
+ efficiency benefit carryover

The cash for each year is calculated and then “smoothed” to reduce year on year volatility. This smoothing is achieved by calculating an “X” amount in the allowance that tariffs will be adjusted by using a factor of CPI –X each year.

The Building Block approach is the basis for the use of both the price cap and the revenue cap forms of regulation. It permits Demand Management initiatives to be built into both these forms of regulation.

Advantages –	**Disadvantages –**
• approach is clear • targeted to the specific business needs • flexible • future oriented • can reset tariffs to reflect changes	• time consuming • complex • higher regulatory cost • regulator involvement in business decisions • needs to be closely managed by regulator • open to debate • open to gaming • once tariff is set changes are more difficult • reviews every five years • encourages network capex rather than best option

APPENDIX 2

Revenue Cap approach

As with price caps, once the revenue needed by the regulated business has been determined, the regulator has to decide how the revenue will be recovered from the users of the regulated service.

The revenue cap approach sets the revenue recovery allowed by the regulated business for each 12 month period.

The difference from the price cap approach is that the tariffs under a revenue cap for the coming year are not adjusted to reflect the over- or under-recovery of revenue from the current year. The only adjustment to the amount of revenue that can be collected for the entire regulatory period is if actual inflation is different to the forecast of inflation used in the setting of the allowed revenue.

Thus the essential difference between the two approaches is that under a price cap, the regulated business takes the risk on the amount of consumption and demand, whereas under a revenue cap, consumers have this risk.

A revenue cap approach cannot use TFP as its basis for adjusting tariffs.

The advantages of a revenue cap are:-

- The amount of revenue to be recovered from users is known by consumers and the network business
- There is no incentive for the business to manipulate tariffs to improve its revenue
- The revenue cap approach readily accommodates large, “lumpy” investments in the network because of the certainty the DB will get its money for the investment. Under a price cap the revenue is dependent on consumption, which reduces the certainty that all revenue will be recovered from the tariffs and therefore that the investment will achieve its needed return.

The disadvantages of a revenue cap are:-

- It provides no incentive for tariffs to be cost reflective
- It does not provide any incentive on the regulated business to modify customer demand or consumption

- It provides no incentive to get better utilisation of the network from either improving load factor[39] or better maintenance practices
- It has no interest in encouraging demand management and might even have a disincentive in the long term as its profits come from the return on the assets its provides – more assets => greater profit

Currently a revenue cap approach is used for all 8 electricity transmission businesses (Powerlink, TransGrid, EA transmission, Directlink, SP Ausnet, Transend, Murraylink and ElectraNet).

It is also used for 4 electricity distribution businesses – Ergon and Energex in Queensland, Aurora in Tasmania and ACTEW/AGL in ACT.

Advantages –	**Disadvantages –**
• doesn’t rely on forecast demands, reducing complexity • tariff manipulation prevented • has no incentive to prevent DSR	• more risk lies with consumers (cost risk) by paying for assets not required • tariffs change with demand levels (eg tariffs rise as consumption, demand reduces) • doesn’t incentivise better economic efficient utilisation • low incentive for alternative solutions • tariff structure signals to consumers to change habits are very muted

[39] Load factor is the relationship between demand and consumption. A low load factor indicates that the network has “needle peaks” in demand, requiring the network to be built for high demands which operate for short periods. As the costs for a network are related to demand, a low load factor means a higher cost for consumers when related to consumption, which is the most common basis for assessing electricity costs

APPENDIX 3

The Price Cap approach

Once the revenue needed by the regulated business has been determined, the regulator has to decide how the revenue will be recovered from the users of the regulated service.

In Australia, the regulators use two approaches for controlling the recovery of the revenue from users – a revenue cap approach and a price cap approach.

The price cap approach sets the revenue recovery allowed by the regulated business for each 12 month period to be related to the **usage** of the network in terms of demand and consumption.

A price cap approach requires a method for adjusting tariffs to accommodate differences between expected inflation and actual inflation. The Rules allow for a number of methods to be used to address inflation adjustments to maintain the allowed revenue. These are by using:-

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

The most common approach used is the tariff basket price control approach, with a schedule of fixed prices for certain services.

With this approach the regulated business develops a set of tariffs intended to recover the allowed amount of revenue, but if these tariffs over or under recover the allowed revenue, then the regulated business is not permitted to adjust tariffs to reflect any over or under recovery in the previous year.

A price cap approach can use both the TFP and building block approaches as its basis for setting tariffs.

The main advantage of a price cap is:-

- It can provide a strong incentive to get better utilisation of the network by improving load factors[40] and better maintenance practices. This is because if consumption is increased using the same assets without increasing demand, then the cost to all consumers reduces on a consumption basis. If the network is better maintained, it will be available when consumers need it and so there will be greater consumption, and under a price cap this means more revenue to the business.

The disadvantages of a price cap are:-

- It can provide little or no incentive for tariffs to be cost reflective but can provide a strong incentive for tariffs to be manipulated to maximise revenue
- The amount of revenue actually recovered from users is not known by consumers
- As it can encourage greater consumption and demand, it has a disincentive to encourage demand management
- As its revenue is dependent on usage forecasts, there is an incentive to under-estimate forecast usage when developing revenue allowances, which can result in higher tariffs, and therefore revenue, being higher than necessary

Currently the price cap approach is used by 8 electricity distribution businesses (EnergyAustralia, Integral and Country Energy in NSW, SP Ausnet, Powercor, Citipower, Alinta and United in Victoria, and ETSA in SA)

Advantages –	**Disadvantages –**
• more risk lies with business • incentivises better economic efficient utilisation by encouraging more consumption • tariff signals can be stronger to change consumption habits	• revenue to business is variable, incentivising the business to find ways to ensure its revenue is maintained, for example, by encouraging consumption • business incentivised to understate future demand growth => more debate with regulator • encourages greater consumption as revenue is related to consumption • does not encourage DSR or reduced consumption • incentivises tariff engineering

[40] See glossary for definition of load factor.

APPENDIX 4

The Total Factor Productivity (TFP) approach

An economic regulator, such as the Australian Energy Regulator (AER), has the task of deciding how much cash a regulated business should be allowed to have each year to provide the services consumers want.

TFP is all about avoiding having the current five year regulatory reset review which is seen as cumbersome, expensive, confrontational and time consuming. Conceptually the TFP is an attractive low cost alternative to the building block approach. It is a move away from cost-based regulation (under price and revenue control approaches) and towards a less intrusive, and high-level approach based on externally-derived indicators.

With the TFP approach, the regulator:

- sets a new regulatory period, commonly of 5-10 years
- sets an accurate starting point of what constitutes the most efficient cost allowance for a network
- agrees on what constitutes the most cost reflective prices (tariffs) for the provision of the services offered
- allows the regulated business to adjust its tariffs using a CPI – X adjustment where X is determined from the movement of costs incurred by a large group of similar distribution businesses over a number of past years (commonly 3-5 years)
- will reassess the tariffs actually applying at the end of the regulatory period in order to be sure that the tariffs are efficient and cost reflective, and that the revenue resulting from the tariffs provides an efficient revenue based on the assets used and the cost to maintain them

The calculation of the TFP adjustment is carried out annually but is relatively straightforward and readily carried out. Because of the TFP uses trends, it is expected that a detailed review of tariffs could be carried out every 10 years or so to identify if the tariffs are still appropriate.

Calculation: New tariff = old tariff*(CPI – X) where X is the developed from the movement of costs in the electricity distribution industry peer group.

The TFP approach makes some basic assumptions to ensure the TFP approach delivers the outcomes expected. These are:-

- the starting point is correct – that the tariffs used at the start really do reflect an efficient and cost reflective price for providing the service
- there is a sufficiently large number of similar businesses to prevent one or two businesses to distort the overall trend (the Victorian government considers that the five electricity businesses in Victoria do constitute a large enough group for this purpose)
- collusion (active or passive)[41] between the businesses will not occur, although the likelihood of at least passive collusion increases over time and also as the number of businesses in the group decreases
- every regulated business will strive to minimise its costs even as their prices increase in the short term, increasing their profits, but knowing that by doing so this will reduce their prices in the longer term

There are a number of matters to consider about the use of TFP in the NEM

- TFP can only be used under a price cap approach, therefore it will only be used for distribution businesses
- When the application of TFP results in a reduction of profits, it could result in detriment to consumers
- Does the NEM provide sufficient convergence of electricity distribution businesses (DBs) activities to support TFP? In this aspect four issues are relevant:

  1. **Ownership**
     There are 12 electricity DBs in the NEM – 2 in Queensland owned by the Qld government (Ergon and Energex), 3 in NSW owned by the NSW government (EnergyAustralia, Integral and Country Energy), 1 in ACT (ACTEW/AGL), 5 in Victoria (SP Ausnet, Powercor, Citipower, Alinta and United) and 1 in both SA (ETSA) and Tasmania (Aurora). However, of these, Singapore Power has a significant interest in ACTEW/AGL, SP Ausnet, United and Alinta, and ETSA, Powercor and Citipower are owned by Spark Infrastructure of which CKI has a significant interest. Thus, these 12 DBs are effectively controlled by five separate entities. This raises the concern about whether there is adequate diversity for TFP

  2. **Differences in Geography Affecting Operating Conditions**
     There is significant diversity between the geographic features of the DBs – 2 are regional/rural (Ergon and CE), 3 are city/regional (Energex, EA and

[41] Active collusion is where the businesses meet and develop a common approach. Passive collusion is where the businesses observe the actions and reactions of the other businesses under certain conditions, and then develop an approach which effectively replicates the outcomes of active collusion. Already in the NEM, generators in a region have been observed to practice passive collusion very successfully.

Integral), 2 are regional (SP Ausnet and Powercor), 3 are city/rural (Aurora, ETSA and ACTEW/AGL) and 3 are city (Alinta, United and Citipower)

3. **Relevance of Revenue Caps for TFP Baseline**
   4 of the DBS are currently operating under revenue caps and are therefore not applicable for TFP (Aurora, ACTEW/AGL, Energex and Ergon) although it is possible the costs incurred by these businesses might be used for evaluating TFP for the other DBs

4. **Differences in Customer Base and Geographic Size**
   There is considerable diversity of size of the customer base for each DB and the geographic area each covers

- Specific demand management schemes should be able to operate within the operation of a TFP approach. As DM will be variable over time and within each DB, the TFP is unlikely to include adequate DM recognition. It is anticipated that therefore demand management will have to be treated in a similar way to the service performance incentive scheme. The TFP approach permits the use of parallel incentive schemes.

Assessments of some overseas jurisdictional uses of TFP

Appendix 5 provides a view of TFP as applied in other jurisdictions.

One of the concerns outlined in this report by EEE about the TFP approach as used in The Netherlands is that this:-

> "…simple approach is adequate when capex is in the trough of the investment cycle (as has been the case to date in the Netherlands), but it takes no account of the need for significant renewal investment. Indeed not only does the current approach provide a disincentive to investment by delaying the time at when the cost of investment is reflected into the control, but if one company invested heavily in a period while the others held off, the control would disbenefit the investing company and benefit those that did not invest. DTe and the companies recognise that this will become an issue to be addressed in the future. A solution may be to treat capex above a certain level as an addition to a TFP control."

This inability to accommodate a significant increase in legitimate capex needs could damage the longer term interests of both consumers and DM proponents.

EEE points out that it would appear that the use of TFP in New Zealand is more of a "hurdle" which if exceeded could result in the application of a Building Block approach. The examples quoted of the US experience would seem to highlight that there the application of TFP is more used as a stating point for continuing the tariffs developed under a “cost of service” model, and that a major element of the application of the discounting “X” factor is a negotiated “stretch” amount to force the “cost of service” tariffs towards economically efficient tariffs.

EEE also notes that the use of TFP in Germany is to regulate some 900 distribution businesses, and notes that statistical analyses are the basis for deriving the outcome. It would appear that statistically a data set of 900+ inputs should provide a sound comparative basis, and that the more rigorous BB approach would create a significant cost burden to consumers.

Advantages –	**Disadvantages –**
• simple • reduces gaming once initial baseline is set • reduces debate • little flexibility once parameters set • regulator minimal involvement in business decisions • lower regulatory cost • can be applied to large numbers of similar businesses, • less frequent reviews • business uses lowest cost solutions • encourages cost efficiency • provides competitive pressure	• relies on collation of longitudinal data from comparable businesses • needs to be closely managed by regulator • needs a large number of participants to develop representative data (is 9 or 13 enough across the NEM – if Vic alone only have 5?) • doesn’t address specific business’ needs • once tariff is set changes are more difficult • setting P_0 right is critical (are these correct now?) no EBSS has been applied symmetrically to give confidence Po is right. AER says need symmetry both to get Po right - only had EBSS for opex • service performance needs to be closely monitored to ensure the business is providing the service • encourages collusion over time • might not be appropriate if there is a need to ramp up capex • outcomes need to be verified after efflux of time

APPENDIX 5

Report from the overseas consultant

REGULATION OF DISTRIBUTION NETWORK SERVICE PROVIDERS –

EXPERIENCE WITH TOTAL FACTOR PRODUCTIVITY CONTROL

EXPERIENCE OF DEMAND SIDE MANAGEMENT

For the Total Environmental Centre

May 2008

Alex Henney

There is a debate in Australia about whether the building block approach (with which Australia has extensive experience and the method is incorporated into the National Electricity Rules) or the total factor productivity (TFP) [42] approach may be "better" for regulating distribution network service providers (DNSPs). Within the context of this paper "better" is taken to mean 1) achieving control that will promote economically efficient development and operation on the part of a DNSP, and 2) encouraging more efficient use of electricity including demand side management.

The disadvantages of the building block approach are the level of detailed analysis required; the informational advantage of the companies; and the difficulty of assessing the need for capex – particularly renewal capex. The advantages claimed for the TFP approach are that it is simple and that it mimics a market, see Annex 1. The first three sections this paper examines how the TFP approach has been applied[43] in:-

- The Netherlands
- New Zealand
- Some cases in the US

The Total Environmental Centre is also concerned to know what mechanics have been devised to encourage DNSPs to develop demand side response. This issue is discussed in the fourth section.

THE NETHERLANDS

Background

[42] A total factor productivity index refers to the productivity of all inputs – labour, capital, materials – as opposed to a partial factor productivity index which focuses on the level (or change in level) of one input such as labour – thus customers/employee is a partial productivity measure (supposing the number of customers is a relevant measure of output) that does not capture all the possible sources of productivity growth (labour may be substituted for capital or vice versa), while customers/total $ cost where $ total cost includes labour, materials and usage of capital is a measure of total factor productivity.

[43] Note that in all the examples there are also controls for service quality, but they are not discussed here.

The number of DNSPs reduced over the last 20 years from nearly 80 to 7 now, of which 3 are dominant each supplying around 2 million meter points and jointly supplying 93% of all the meter points in the Netherlands. All of the DNSPs are owned either by municipalities or provincial governments. A new regulatory authority, DTe, was created in 1998. DTe observed that there are two general approaches to benchmarking that have been used by regulators:-

- setting the X factor equal to the average total factor productivity growth rate of the relevant industry, which is an "unlinked" approach that "delinks" the setting of X from the behaviour of individual regulated utilities

- cost linked benchmarking such as used in the UK [and Australia]

Longer term DTe wanted to move to the unlinked method of "yardstick regulation" for the distribution companies, which means that the regulated prices are not linked to efficiency judgements based on the costs of the individual companies, but reflect the scope for efficiency of a typical or average company in the sector. As DTe observed "The aim is to simulate the operation of a competitive market through yardstick competition…Through its decoupling of the network company's own costs and the tariffs, the system of yardstick competition provides a strong incentive to reduce costs". This average is the yardstick. In this way companies performing better than average would make an above-average rate of profit, and conversely for those performing poorly where the return would be worse than the average.

For various reasons DTe's first attempt at setting controls for the period 2001-03 was a disaster that ended in the courts and chaos, but it got its act together for the second (2004-06) and third (2007) regulatory periods.

<u>The second (2004-06) and third (2007) regulatory periods</u>

For the second regulatory period of 2004-06 DTe consulted with the DNSPs and developed an approach for benchmarking them using a simple quasi total factor productivity index for each DNSP which it devised of:-

$$\frac{\text{total cost of inputs}}{\text{value of output}}$$

The cost of inputs includes a charge for capital based on a return on standardised assets equal to the weighted average cost of capital derived by assuming a debt/equity ratio of 60/40; calculating a debt premium above a risk free premium from comparable private undertakings; and using the capital asset pricing model to estimate the cost of equity capital. The result was a real pre-tax return of 6.6%. The value of output was derived by first calculating the average national unit charge for supply at each voltage level, and then applying the respective figure to the volume of supply at each voltage level by a particular DNSP.

DTe set an X for all distributors based on the average efficiency improvement for the whole sector (which it forecast as 1.5% p.a., but in the event it was 1.1% and so there were corrections made for the next period) plus catch-up factors for each company to achieve the level of efficiency of the most efficient company by the end of the period. The relative level of efficiency was measured by the ratio of the index for each company to that of the most efficient company.

DTe considered that the second regulatory period had brought total allowed revenues of distributors into line with their efficient costs, and consequently in the third regulatory period the underlying efficiency X factor was the same for all distributors and was based on the average annual change in productivity of *all* distributors during the years 2003-05 (viz 1.1% p.a.).

This simple approach is adequate when capex is in the trough of the investment cycle (as has been the case to date in the Netherlands), but it takes no account of the need for significant renewal investment. Indeed not only does the current approach provide a disincentive to investment by delaying the time at when the cost of investment is reflected into the control, but if one company invested heavily in a period while the others held off, the control would disbenefit the investing company and benefit those that did not invest. DTe and the companies recognise that this will become an issue to be addressed in the future. A solution may be to treat capex above a certain level as an addition to a TFP control.

NEW ZEALAND

In the mid 1990s, when restructuring its electricity industry, New Zealand did not create an industry regulator but relied on self-regulation (which is an oxymoron) coupled with (hoped for) cost transparency. Predictably the approach failed. In 2001 legislation was introduced that requires, among other things, the Commerce Commission (which is the general competition authority) to implement a "targeted control regime" for the 28 DNSPs. In the words of the Commission "the thresholds are a screening mechanism to identify lines businesses whose performance may warrant further investigation and, if required, control by the Commission".

The "thresholds" approach is unique. It is intended to be a mechanism for identifying DNSPs companies whose performance *may* warrant further examination, which - depending on the findings - could lead to formal control of prices and/or service quality levels. Control is "targeted" in the sense that a company can only become subject to control by breaching an established threshold.

In the scheme put in place from April 2004 the thresholds were set using X-factors that were based on:-

- a B factor of -1.0% p.a. reflecting expected industry-wide improvements in efficiency, determined through TFP analysis

- a C factor, reflecting the relative performance of groups of distribution businesses. DNSPs were ranked by relative efficiency (which was measured by TFP and other statistical methods) and allocated to 3 groups and given a supplementary C factor – more efficient (-1% p.a.); averagely efficient (0% p.a.); and less efficient (1% p.a.) Then X = B + C

To recap, the thresholds are like a "soft" price control – a DNSP can breach it, but if it does so then it may be subject to an investigation that will be building block like, and may be followed by an enforced control.

SOME TFP SCHEMES IN THE US

The US generally continues to use traditional cost of service regulation, but in the 1990s some states which unbundled generation from networks experimented with “performance based ratemaking” (PBR) which can incorporate a TFP approach. Unlike a price/revenue control regime, PBR involves setting a company a target rate of return on equity and a price control (US jurisdictions rarely use price caps, but see below) for a period of time, which is typically 5 years. There is then a sharing arrangement for the upside and downside for the actual return. For example in the case of San Diego Gas & Electric’s scheme starting in 2000, the price control was based on a TFP of 0.92% p.a. to which a “stretch factor” of 0.7% p.a. was added to give a total X of 1.62%. The stretch factor was justified by the proposition that since the companies had been subject to cost pass through regulation they must be somewhat inefficient, and so a PBR incentive regime will squeeze out the inefficiency. The stretch factor is a deal. Shareholders retained all excess earnings up to 25 basis points above the target rate of return and above 300 basis points. Between those limits the shareholders earned from 25% progressively increasing to 95% of excess earnings; customers received the difference. Shareholders took any downside.

The first index scheme in Massachusetts was for Boston Gas, which indexed rates to the historic total factor productivity of the economy minus that of input prices for gas distribution utilities in the North East together with a stretch factor. The scheme for New England Electric System’s merger with Eastern Edison Company agreed a small reduction of rates in the first year then fixed rates in nominal terms for the succeeding four years. Subsequently the rates were adjusted annually by an index based on an average of the distribution charges of investor owned electric utilities with unbundled rates in New England, New York, New Jersey, and Pennsylvania.

INCENTIVISING DEMAND SIDE MANAGEMENT

In many jurisdictions distribution charges are based on a mix of a capacity charge to reflect the local connection cost and possibly shallow reinforcement costs, and a power flow charge (kWh). The latter factor gives the DNSPs an interest in power flow increasing and consequently a disincentive to promote demand side measures. Where there are competitive markets very few jurisdictions appear to be looking to the DNSPs to implement demand side measures. Many European countries have no interest in the topic, while those that do look to the retailer (e.g. Britain, France) – there is no scheme in either country to incentivise demand side management by the DNSPs. There are few jurisdictions making the effort that the Electricity Services Commission of South Australia is requiring of ETSA Utilities.

Nonetheless there are some efforts which start with removing the DNSPs interest in power flow increasing by changing from price control of unit rates to either revenue control or compensating a DNSP for any loss of revenue from the implementation of demand side measures. The next step is to subsidise demand side measures. The final step is to devise a mechanism which provides DNSPs with an incentive to introduce demand side measures, which has been suggested in broad outline in New Zealand.

The Massachusetts Department of Public Utilities has been holding a hearing to devise a mechanism to “decouple” the revenue of network companies from reductions in powerflow. Essentially this means switching from multi rate price control to revenue control, and allowing compensation to the DNSPs for lost revenue through what it calls a “base rate revenue adjustment mechanism” (the method for which is explained in Annex 2). This adjustment reflects the mechanism by which the revenue cap is adjusted each year to manage the “unders and overs” of revenue recovered in the preceding year. The legislature is considering a bill to separately recompense utilities for investment in demand side measures.

There are three programmes for demand reduction/energy efficiency/distributed generation in the service territory of Consolidated Edison, the DNSP serving New York City:-

- a programme administered by Con Edison which is largely aimed at peak shaving to reduce investment in upgrading the network by measures such as programmable thermostats, higher efficiency lighting programmes, installing higher efficiency air conditioning systems. The objective is to reduce demand by 150MW

- a statewide programme run by the New York State Energy Research and Development Authority intended to conserve energy by getting customers to install more efficient equipment through direct installation and rebate programmes which are funded by a surcharge on bills. The programme aims to reduce demand by 550MW

- a programme by the Authority which is particular to Con Edison's service territory and is funded by a levy included in the rates which aims to reduce demand by 300MW

These programmes reduce customers' power consumption, and hence the revenue of Con Edison. It is compensated for the direct costs and associated lost revenues for the statewide programmes and the targeted (company) programme. It is paid $22,500/MW of demand management achieved up to a three year limit of $15.88m for the programme which it runs.

The Commerce Commission in New Zealand has a stated objective of incorporating an incentive for demand management into the pricing structure but, with impending legislation and an election, the reset of thresholds has been deferred from 2009 to 2010 and work on the reset has been deferred. The transmission charge has a significant charge related to peak demand, and currently the transmission charge is a pass through. The initial thinking was to allow (say) half of the charge as a pass-through and impose the other half on the DNSP. This would provide a sharp incentive for demand management.

Annex 1 <u>Pricing by TFP emulates pricing in a market</u>

For a competitive industry over medium to long term periods[44] the trend (symbol Ξ) in output prices (ΞP) equals trend in *unit* costs (ΞC), that is:-

$$\Xi P = \Xi C \tag{1}$$

Now the trend in unit costs in an industry equals the difference between the trends in input prices to the industry (ΞIP) and the trend in its “total factor productivity” (ΞTFP_{ind}) i.e.

$$\Xi C = \Xi IP - \Xi TFP_{ind} \tag{2}$$

Since $\Xi P = \Xi C$, then for a regulated process to mimic the competitive market standard prices should change year on year by the following formula:-

$$\Xi P = \Xi IP - \Xi TFP_{ind} \tag{3}$$

For the economy as a whole the change in input prices equals the change in output prices plus the change in the TFP for the whole economy (ΞTFP_{econ}).

Thus we have the following relationship:-

$$\Xi IP = (\text{either } \Xi CPI \text{ or } \Xi GDP\text{-}PI) + \Xi TFP_{econ} \tag{4}$$

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[44] Over the short term the relationship between prices and unit costs will fluctuate, and for a capital intensive business may fluctuate in a seemingly perverse way. Namely when the market is “soft” (demand is weak) prices will be relatively low while unit costs (i.e. <u>fixed costs</u> + variable cost/unit) will be high.

number of units

If (and only if) the measure of economy-wide inflation (e.g. CPI) reflects accurately the change in input prices to an industry, then substituting (4) into (3):-

$$\Xi P = \Xi CPI + \Xi TFP_{econ} - \Xi TFP_{ind} \quad (5)$$

If, however, there is a difference between the trend of input prices to the industry and the index used to measure economy wide inflation (in this case ΞCPI), then there has to be a further adjustment equal to (ΞIP - ΞCPI) - call it the trend in differential input prices ΞDIP. Then equation 5 becomes:-

$$\Xi P = \Xi CPI + \Xi DIP + \Xi TFP_{econ} - \Xi TFP_{ind} \quad (6)$$

(Note that the potential significance of the input price differential is not widely understood).

Annex 2 The proposed Massachusetts base rate revenue adjustment mechanism intended to promote efficient deployment of demand resources[45]

The key elements of the proposed "base revenue adjustment mechanism" are as follows:-

- Each company's base distribution revenues will be reconciled on an annual basis to ensure that they are closely aligned with costs. This reconciliation is intended to ensure that a company will not be harmed by reduced sales nor will it experience financial benefits from increased sales
- Each company will be allowed to recover a fixed amount of revenues per customer, for each customer class. This provision is intended to ensure that revenues are more closely aligned with a significant driver of costs on a company's system – the number of customers
- The Department of Public Utilities will determine each company's allowed revenues and allowed revenues per customer in the context of a base rate proceeding, using well-established ratemaking precedent including cost of service, cost allocation, and rate design. Allowed revenues will be collected through base customer, energy, and demand rates, established by customer class
- Every twelve months, each company will submit a reconciliation filing for Department review. Such filings will be used to make any reconciliation adjustments for the preceding year and to set the new base energy rates for the subsequent year
- Each company's reconciliation filing will compare actual revenues with allowed revenues for the preceding year and will adjust base energy charges up or down to reconcile for differences. The adjustment in base energy charges also will include the recovery of an appropriate level of revenues for the subsequent year, calculated by multiplying the allowed revenues per customer by the projected number of customers
- In its initial base rate proceeding establishing a new revenue recovery mechanism, each company will assess the extent to which the base revenue adjustment mechanism affects the company's risk profile and how any change in its risk profile should be incorporated in the company's rate structure

According to the Department the base revenue adjustment mechanism should be designed to meet or appropriately balance the needs to:-

- better align the financial interest of electric and gas distribution companies with customer interests, demand resources, price mitigation, environmental, and other policy objectives

[45] Docket No. DPU 07-50, 22 June 2007.

- ensure that electric and gas distribution companies are not financially harmed by the increased use of demand resources
- meet the Department's rate structure goal of efficiency by more closely aligning company revenues with costs
- meet the Department's statutory obligation to investigate the propriety of gas and electric rates in a way that is consistent with Department ratemaking precedent, including the review of cost-of service studies, cost-allocation, and rate design
- be consistent with Department precedent related to rate continuity, fairness, and earnings stability
- appropriately balance the risks borne by customers and those borne by shareholders
- advance the goals of safe, reliable, and least-cost delivery service and promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden
- be applied uniformly across all electric and gas companies, to the extent appropriate and reasonable
- be simple, easily understood, and transparent

Under a base revenue adjustment mechanism, a company's revenues would be reconciled on a regular basis. If a company's sales volume changes over time, leading to lower distribution revenues than were allowed at the time rates were set, then the difference in revenues would be determined and periodically reconciled through distribution rates. This periodic reconciliation ensures that revenues would be more closely aligned with costs over time. Further, a company would not be financially harmed by or benefit from changes in sales.

Annex 3 <u>Responses to specific questions</u>

- Under a price cap, the DNSP is incentivised to increase consumption and demand which is an active disincentive to demand management

Response - agree

- A revenue cap provides no incentive for demand management, but neither does it incentivise demand management (DM)

Response - agree

- The DM approaches currently in place seem only to recompense the DNSP for the revenue they would lose by implementing the DM

Response – the reality is that in general people are merely playing with incentivising DNSPs

- Are the examples you provide based on incentivizing the demand and consumption reduction?

Response - Yes.

For example the $22,500/MW of demand reduction provided to Con Edison would seem to be well below the cost of new generation which is $0.8-2m/MW installed.

Response - Agreed, but the objective is not to pay for new embedded generators, but (for example) to encourage use of existing standby generators in commercial buildings and trimming of air conditioning systems at peak times

- Is the $22,500/MW payment for a reduction in demand (ie MW) additional to any compensation for the loss in revenue caused by reduced consumption (ie MWh)?

Response - Yes.

It can bee seen that there is a benefit from reducing demand as this would result in less capex for the DNSP, but if the consumption associated with this demand is merely time shifted, then there is no reduction in consumption (MWh) and hence no loss of revenue

- Currently the regulatory test used in Australia uses $10k/MWh (or $29.5k/MWh in Victoria) to justify new network investment. Do other jurisdictions use this sort of approach to justify investment? Do they use this as a cost indicator for DM (ie for the savings that DM would deliver)?

Response - The other countries cited with TFP do not have the NEM type of regulatory test figures for general DNSP investments, which are rolled into the TFP

With regard to TFP:

- It is understood that TFP is used in Germany as well. Does the German approach follow the Netherlands approach, and therefore could be equated with the Netherlands approach?

Response – I had not quoted for Germany because I have never analysed its regulation. Germany uses data envelopment analysis (DEA) and stochastic frontier analysis (SFA) to benchmark the 900 odd distributors

- In the Netherlands (and Germany), are the DNSPs considered to be reasonably similar in relation to terrain, population density, rural vs urban, etc or are there significant differences between them in relation to these factors. The concern is that if they are reasonably similar, then there might be a concern that where there are significant differences DNSPs like in the NEM, then maybe TFP is less appropriate.

Response - The Dutch DNSPs are considered similar except for one which serves the delta of the Rhine. As you probably know, the Netherlands is flat. Germany is flat in the northern plain and mountainous in the south

- You make reference to TFP in the Netherlands section to the capex trough. Was this issue one raised by DTe and do they make adjustments for variances between DNSPs with differing capex needs?

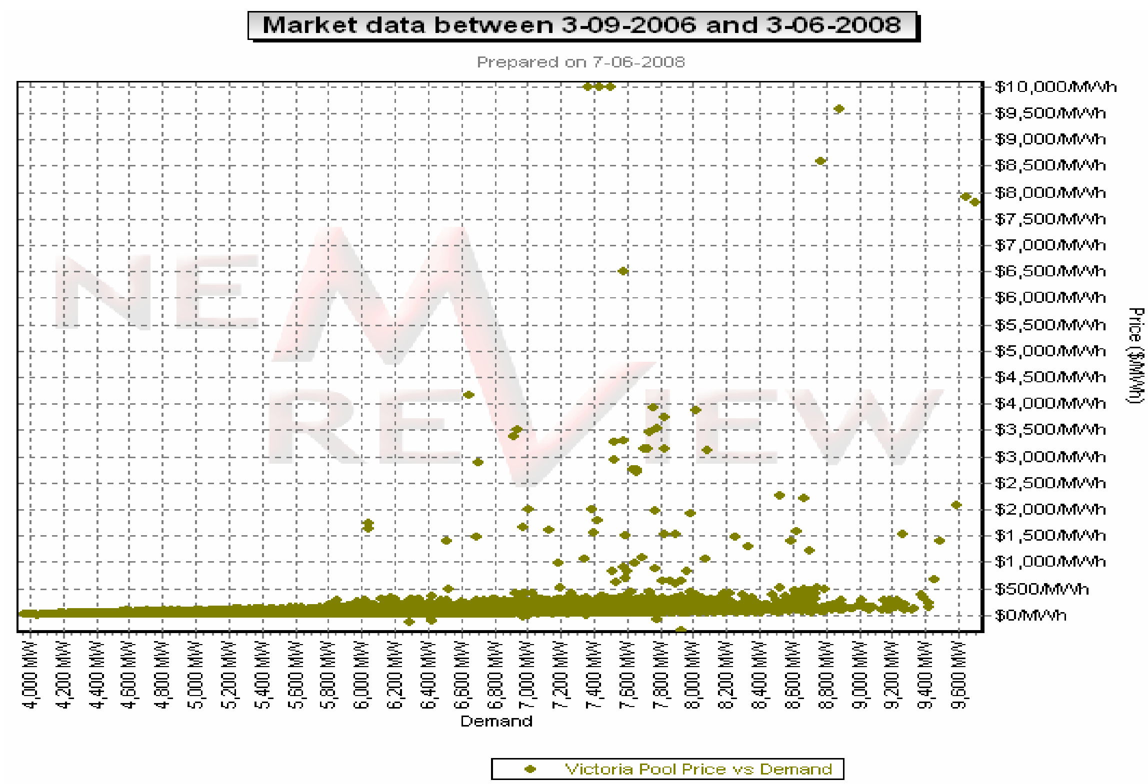
Response - They are in an investment trough (see p4), so the issue has not yet arisen. In Australia some DNSPs are spending up big because the regulator accepts their claims. Compare this to the Victorian DNSPs, after being permitted large capex allowances 2000-2004, actually spent only two thirds of what they were allowed, and the next period has only allowed them capex following the trend they set from the last period – this means that capex allowances are no longer being assumed to reflect the "bow wave" effect.

APPENDIX 6

System DM and the impact of a disaggregated market

Demand management has two basic effects – the first is on the supply of electricity and the second is on the transport of electricity. There are many times when these effects are not concurrent, and at other times when they do occur concurrently.

Demand management in relation to the supply of electricity is driven by the need to limit the amount of electricity being used when the generation available has reached its limit. A reduction in demand at such a time might be signalled by the price of electricity (but not always as can be seen in the chart below), by load shedding (ie by preventing some consumers from being supplied) or by the market operator entering into unique contracts to provide additional electricity from non-traditional sources (Reserve Trader).



As can be seen from the above chart, there is not a strong relationship between demand and price (especially very high prices). If system demand and price do not show a strong relationship, then this directly impacts on the efficacy of the spot market to incentivise demand management at any given point in time.

In the NEM the supply of electricity (generation) has been separated from the transport of electricity, with generation being considered to be a contestable function and the network to be a natural monopoly function. This separation means that the economic signals resulting from the system pricing element of the NEM (the contestable element) have a significantly reduced applicability to the network function (the monopoly element). The direct result of this separation is that the economic signals developed for the contestable element have marginal use for the monopoly element (networks) and therefore the economic signals for networks tend to be developed in isolation of the market as a whole.

This contrasts to the ability of demand management being able to benefit from the integration of both elements, such as occurs in many overseas electricity markets which are based on vertically integrated generation and network service providers (this aspect is discussed later in this report).

However, the purpose of this paper is not on system demand management but on the approach to network regulation and its impact on demand management.

APPENDIX 7

Win, Win, Win: Review of NSW D-Factor

A report for TEC by Institute for Sustainable Futures (ISF), UTS & Regulatory Assistance Project January 2008

ISF Recommendations:

1. Clarify government policy intent regarding efficient Demand Management.
In recognition of the scope of demand management (DM) both to advance the long-term interests of consumers and to enhance environmental sustainability, State, Territory and Federal Governments should ensure that the National Electricity Law and the National Electricity Rules:

- explicitly require the Australian Energy Regulator (AER) to make efficient regulatory determinations in relation to DM
- explicitly require Distributors to undertake all cost-effective DM, prior to network augmentation.

2. Align network incentives with consumer and public interest.
In making regulatory determinations, the AER should avoid creating incentives that set the financial interests of the Distributors in conflict with the interest of their customers. In particular, incentives against DM should be avoided in relation to:

- short-term incentives (within regulatory periods) associated with price/revenue control formulae (see Recommendations 3 to 8)
- long-term incentives (between regulatory periods) associated with prudence review and the incorporation of capital expenditure into the capital base and mechanisms for sharing efficiency benefits between shareholders and consumers (see Recommendations 9 to 11)
- network system development and planning requirements (see Recommendations 12 to 14).

3. “Decouple” Distributor profit from electricity sales.
In setting its year-to-year price control formula, the AER should as a key priority, decouple Distributor revenue and profit from electricity sales volume. That is, the AER should ensure that the profitability of a Distributor is not linked to the amount of electricity carried through its network and consumed by its customers.

4. Use Revenue caps to decouple network profit from electricity sales.
In order to decouple electricity consumption and Distributor revenue and profitability, the AER should apply a revenue cap in preference to a price cap in regulating Distributors.

5. Link revenue cap to economic growth.

In applying a revenue cap, the AER should consider applying adjustment factors to insulate Distributors from large divergence of actual peak demand from forecast peak demand. This could, for example, be applied by linking the annual revenue cap to movements in measures of economic activity, such as Gross State Product.

6. Use D-factor if revenue cap precluded.

In circumstances where it is not possible to apply a revenue cap (for example, where a commitment to a price cap has already been made, as in NSW for the forthcoming regulatory period), other revenue decoupling or “lost revenue adjustment” mechanisms should be applied (such as the NSW D-factor).

7. Create a “use it or lose it” component in the D-factor.

Where a “lost revenue adjustment” mechanism (such as the D-factor) is established, it should be applied with a default ex ante allocation on a “use it or lose it” basis that assumes some (non-trivial) level of DM will be undertaken by the Distributor. A D-factor of at least 2% of annual proposed capital expenditure could provide a reasonable default ex ante allocation.

8. Allow recovery of long-term DM costs in D-factor.

Distributors should be permitted to recover, through the D-factor, costs associated with low cost “long-term DM” opportunities that would otherwise be lost if they are delayed until a local network capacity constraint emerges.

9. Allow Distributor savings from DM to be carried forward.

The AER should ensure that Distributors are permitted to carry over efficiency benefits from DM, such as deferral or avoidance of capital expenditure, from one regulatory period to the next, on no less favourable terms than they are able to continue to earn a return on network capital investment from one period to the next.

10. Ensure balanced prudence review of capital expenditure.

Recognising that short-term incentives are likely to have little impact unless complemented by longer-term incentives, the AER should ensure that the review of prudence of past and projected capital expenditure involves a thorough all-sources assessment of the opportunities for deferring capital expenditure through DM, conducted by experts with a demonstrated balanced understanding of the theory and practice of DM.

11. Require Distributors to demonstrate efforts to procure DM.

The AER should require Distributors to demonstrate that they have undertaken reasonable efforts to identify and procure cost effective DM, particularly in the context of anticipated network constraints and proposed new network investment. Such efforts should include DM direct offers to consumers, DM programs developed by the Distributor and DM proposals solicited from other parties.

12. Inform the DM market.

The AER should seek to inform the market for DM options by requiring Distributors to publish detailed information annually about the current capacity of the distribution network, current and projected demand and possible options to address any emerging constraints.

(The NSW DM Code of Practice for Distributors and the South Australian Guideline 12 provide sound precedents for such information disclosure.)

13. Ensure consistent Distributor DM performance reporting.
The AER should require Distributors to report annually on DM activities undertaken in relation to: expenditure, peak demand and energy consumption reductions, value of electricity sales foregone, value of capital and operating expenditure avoided or deferred, and efforts to identify and procure cost effective DM. Such reports should be publicly available. The AER should issue a pro forma to encourage consistency in DM reporting. Reporting to the AER should be harmonised with any other DM reporting requirements.

14. Conduct and publish annual AER DM Reviews.
In recognition of the relatively underdeveloped state of DM in Australia, the AER should monitor DM data provided by Distributors and publish a consolidated annual review to encourage mutual learning and allow comparison of different policies and approaches between jurisdictions. (This will also assist in building understanding of DM potential within the regulatory community and among stakeholders.)

15. Apply complementary transitional measures to accelerate DM.
Recognising that the above measures are designed simply to address existing barriers to efficient DM in the economic regulatory environment, and that the DM market in Australia is currently underdeveloped, Federal, State and Territory Governments should establish complementary transitional measures to create positive incentives to develop DM quickly.

16. Put an appropriate price on greenhouse gas emissions.
In the interests of economic efficiency, and in recognition of the high economic cost that climate change is expected to impose on the Australian and global community, the Australian Government should ensure that the price of greenhouse gas polluting activities, such as fossil fuel-based electricity generation, includes the full cost of the associated greenhouse gas emissions. This could be achieved by introducing an emissions trading scheme or a carbon tax. (Recommendations 1 to 15 would be complementary to such action.)

APPENDIX 8

NEM Advocate Forum - key questions arising from evaluation of each of the approaches

In the tasks assigned to the consultants by TEC and in the two forums convened by TEC, a range of questions and issues were raised which participants considered were relevant in the context of evaluating each of the forms of regulation adopted by regulators. These questions are listed here:

- Is the building block approach appropriate for non-network solutions?
- Should the network be paid a profit element over and above the cost of a non-network solution?
- Is the BB approach better for DM programs because it is transparent?
- Does either a revenue cap or a price cap impact demand and consumption?
- Which revenue recovery mechanism has the best (less worse) consumer impact for reducing usage?
- How to overcome the disconnect between encouraging less consumption when a price cap implicitly encourages increased consumption?
- Is a capacity market more conducive to self generation (ie a DM approach) than an energy only market?
- Does either approach support or resist the likelihood of networks to undertake demand management?
- Should economic efficiency be the only element of the NEM objective in relation to networks? If not, how should the objective be re-written?
- Should the Rules provide an active incentive (another distortion from economic efficiency) to encourage more demand management and/or self generation?
- Should network costs be charged only for demand? If so, should there be higher demand tariffs for peak times and lower for off peak times?
- Should networks be required to charge only for the highest demand in a shorter period (eg a quarter, month, week)?

- Should network costs still be incurred for providing stand by capacity?
- Are the funds sufficient provided in current DM programs (eg in NSW D-factor scheme and SA funded trials)? Do these programs provide a result?
- How will such programs (as in NSW and SA) apply under a TFP approach?

The following participants attended the TEC forums:

National Electricity Market Advocates

Kerry Connors	Executive Officer	Consumer Utilities Advocacy Centre, Vic
Tosh Szatow	Policy Officer	Consumer Utilities Advocacy Centre, Vic
Gerard Brody	Director, Policy and Campaigns	Consumer Action Law Centre, Vic
Brad Shone	Energy Policy Manager	Alternative Technology Assn, Vic
Marie Andrews	Program Manager Energy Services	Kildonan Uniting Care, Vic
Ian Jarratt		Qld Consumers Association, QLD
Mark Henley	Manager Advocacy and Communications	Uniting Care Wesley, SA
Tony Westmore	Senior Policy Officer (electricity)	Australian Council of Social Service, NSW
Joyce Fu	Energy Program Coordinator	Ethnic Communities' Council of NSW
Mark Ludbroke	Senior Policy Officer	Public Interest Advocacy Centre, NSW
Joel Pringle		Public Interest Advocacy Centre, NSW
Glyn Mather	National Electricity Market Advocate	Total Environment Centre, NSW
Jane Castle	Resource Conservation Campaigner	Total Environment Centre, NSW

Expert Contributors

Mike Peevey	President	California Public Utilities Commission, USA
Chris Dunstan	Research Principal	Institute for Sustainable Futures, UTS, NSW

Consultants

David Headberry	Headberry Partners P/L
Bob Lim	Bob Lim – economics and public policy

Facilitator

Richard Maguire	Unfolding Futures

APPENDIX 9

Excerpt from

PHOTOVOLTAIC ENERGY BAROMETER, April 2008

TOTAL EU INSTALLED CAPACITY IN 2007 4689.5 MWP

Thanks to a German market at its peak associated with the rise in importance of the Spanish and Italian markets, the European Union established a new record for photovoltaic installations.

According to first estimates, 1 541.2 MWp were installed in 2007 (+57% with respect to 2006), bringing total EU installed capacity up 4 689.5 MWp.

The German market recovers
It must be admitted that the estimates of photovoltaic capacity installed in Germany during the year 2006 got carried away. AGEE Stat, which produces the renewable energy statistics for the BMU (Ministry of the Environment), revised its estimate published last May downward, with 830 MWp installed in 2006 (vs. 950MWp initially announced). In this way, this body corroborates the final figures from *Photon International* magazine, published last December, resulting from their annual inquiry and survey with German power grid managers. Very far indeed from this magazine's first estimate published in March 2007 (1 150 MWp) which was based on the number of inverters sold in Germany.

2006 will thus have been marked by a stagnation of the German market, with 866 MWp having been installed in 2005. This stagnation can be explained more by a shortage of equipment than by a downturn in demand. As proof of this situation, the recovery which was announced for 2007 with a first estimate of the BSW (German Solar Industry Association) of 1 100 MW. This estimate, which is judged credible by Christel Linkhor of AGEE Stat, shall bring Germany's total installed capacity to 3 846MWp, i.e. nearly 82% of total European Union installed capacity.

More than ever, the German market is thus a moving force behind world photovoltaic growth. It continues to be largely ahead of the Japanese market which should, according to EPIA, remain stable in 2007 (286.6MWp installed in 2006) and the American market, estimated at 205 MWp in 2007 (143 MWp installed in 2006) according to a source (Sherwood Associates, member of the Board of Directors of the Interstate Renewable Energy Council) reported by *Photon International* magazine.

The performances of the German market are explained by the stability of the incentive system which made it possible to give investors more clarity and so structure the market. Since August 2004, the renewable energies law (EEG) obliges electricity suppliers to buy photovoltaic electricity. The tariff applicable for a period of 20 years decreases by 5% each year for systems linked to a construction and by 6.5% for systems not linked to a construction. The tariff varies according to the capacity of the installation. On buildings, it is established in 2008 at between 0.4675€/kWh ($0.78/kWh) for power plants smaller than 30 kW and 0.4399€/kWh ($0.73/kWh) for power plants larger than 100 kW. A 5 €c bonus ($0.08) is added for power plants that are integrated in building façades. Ground based PV systems benefit from a tariff of 0.3549€/kWh ($0.59/kWh). A revision of the EEG law should take place in the next few months. In particular, negotiations concern a rise in the yearly price decrease rate.

APPENDIX 10

CPUC news release, 20 Sep 07

PUC CREATES INNOVATIVE NEW PLAN FOR ACHIEVING STATE'S GROUNDBREAKING ENERGY EFFICIENCY GOALS

SAN FRANCISCO, September 20, 2007 - The California Public Utilities Commission (PUC) today approved an innovative new framework for achieving and exceeding the state's aggressive and groundbreaking energy efficiency goals. This new plan is critical in California's efforts to fight global warming.

Today's decision establishes a new system of incentives and penalties to drive investor-owned utilities above and beyond California's aggressive energy savings goals. The new program provides incentives of sufficient level to ensure that utility investors and managers view energy efficiency as a core part of the utility's regulated operations that can generate meaningful earnings for its shareholders.

At the same time the new framework:

- Protects consumers' financial investment;
- Ensures that program savings are real and verified; and
- Imposes penalties for substandard performance.

Earnings to shareholders accrue only when a utility produces positive net benefits (savings minus costs) for ratepayers. The shareholder "reward" side of the incentive mechanism is balanced by the risk of financial penalties for substandard performance in achieving the PUC's per kilowatt, kilowatt-hour, and therm savings goals.

PUC President Michael R. Peevey said, "The culture of a business is often, if not always, defined by how that business makes money. As a result, in the utility world, energy efficiency has traditionally played second fiddle to the generation and transmission side of the business. Today's decision changes that view. It's my hope that California's innovation serves as a template for other states around the Nation."

"We must adopt aggressive new tools to fight global warming. Today's decision is part of California's commitment to make energy efficiency 'business as usual' in California," said Commissioner Dian M. Grueneich. "The risk/reward incentive encourages utilities to invest in energy efficiency the same way they would invest in a power plant. Our efforts will reduce global warming by an estimated 3.4 million tons of carbon dioxide by 2008, which is equivalent to taking about 650,000 cars off the road."

"This decision puts energy efficiency on an equal footing with utility generation. It will align utility corporate culture with California's environmental values," said Commissioner Timothy Alan Simon.

Earnings begin to accrue at a 9 percent sharing rate if the utility meets 85 percent of the PUC's savings goals. If performance achieves 100 percent of the goals, the earnings rate increases from 9 percent to 12 percent. Each earnings rate is a "shared-savings" percentage. This means, for example, if the combined utilities achieve 100 percent of the 2006-2008 savings goals and the verified net benefits (resource savings minus total portfolio costs) at that level of performance is $2.7 billion, then $2.4 billion (88 percent) of those net benefits goes to ratepayers and $323 million (12 percent) goes to utility shareholders. If utility portfolio performance falls to 65 percent of the savings goals or lower, then financial penalties begin to accrue.

Today's decision builds upon California's landmark policies to advance clean air and energy, such as the Global Warming Solutions Act (Assembly Bill 32), the Low Carbon Fuel Standard (Executive Order S-01-07) and Emissions Performance Standard (Senate Bill 1368), and follows the direction of the state's Energy Action Plan.

For more information on the PUC, please visit www.cpuc.ca.gov.

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APPENDIX 11

Glossary of Terms

Bow Wave capex program

The bow wave capex program is the name given to the rapid increase in capex needed as a result of lower than required spending in previous years. It particularly is referred to in relation to the supposed low capex by the NSPs when owned by government prior to corporatisation (and even privatisation). The new corporate bodies observed that there was a need to increase capex after the transition. It is interesting to note that some NSPs have not spent all the capex the regulators granted in response to the bow wave effect

Building block

A technique used to assess a network's reasonable needs for revenue. See appendix 1

Capacity market

A capacity market is one where the capacity to generate is paid for as well as a payment for the amount of electricity that is provided. The WEM (electricity market in WA) is a capacity market. See energy only market.

Capex Capital expenditure: This is the amount of new capital invested in the network for replacing old assets and building new assets

Capital This is the sum of debt and equity used by a network

Cost of service regulation

Cost of service regulation is an approach in which the actual costs for providing the service are reviewed by the regulator, and used to set tariffs. It is closest in analogy to the BB with revenue cap. This approach is considered to be even more invasive than the approach used in the NEM, which is based around incentive regulation.

Debt This is funding provided by a lender to a network

Demand This is the rate at which electricity is consumed and is measured in kilowatts (kW)

Demand management (DM)

The technique used for managing the demand of a consumer and includes permanent demand reductions, for example, from the retrofit of major developments. It is also referred to as demand side management (DSM). Demand side responsiveness (DSR) falls under the umbrella of DM.

Demand side responsiveness (DSR)

This is a term referring to the responsiveness a consumer makes to signals in the market to modify the demand of the consumer. The most common forms of DSR are: short-term load curtailment provided on a contractual basis to networks or demand side aggregators, and on-site generation.

Depreciation
This is the loss of value of the assets of a network over time. It is referred to as the return of assets.

Efficiency Benefit Sharing Scheme (EBSS)
This is a scheme developed by the regulator to encourage a regulated business to reduce its costs over time. It allows the business to retain over a longer period, the benefits of reducing its costs

Energy only market
The NEM is an energy only market. In an energy only market, all electricity is trading by the amount of electricity used in a half hour basis. See capacity market

Equity This is funding provided by shareholders of a network

Externally Derived Indicators
These are indicators derived exogenously to the electricity industry, but could be used to set new tariffs. The most common one used in the electricity industry is CPI, but also include producer price indices and labour indices

Gearing This is the relation between debt and equity used by a network

kW kilo watt. A demand of one kW for one hour provides one kWh

kWh kilo watt hour. This is a unit of consumption of electricity

Load Factor Load factor is the relationship between demand and consumption. A low load factor indicates that the network has “needle peaks” in demand, requiring the network to be built for high demands which operate for short periods. As the costs for a network are related to demand, a low load factor means a higher cost for consumers when related to consumption, which is the most common basis for assessing electricity costs

LRMC Long run marginal cost, The cost a business needs to recover its costs for providing the service, including a reasonable return on the assets it provides and the risks it faces by providing the service

NEM National Electricity Market, which provides the electricity supply in Queensland, NSW, ACT, Victoria, SA and Tasmania

Network This is the “poles and wires” needed to transport electricity from a generator to a consumer

NSP Network service provider – the business that provides the network including augmenting it to meet the needs of consumers

Opex Operating expenditure. This is the amount of money expended by the network for managing the network

Price cap See appendix 3

Ratcheting This is the process where a network business measures the single highest demand used in the previous 12 month period, and charges the consumer regardless if the demand is reduced in this period

Regulation The approach use to ensure that providers of monopoly services receive a reasonable (but no more) income for providing the monopoly service

Regulatory period
This is the period for which a regulatory decision will apply. It is most commonly a period of five years

Regulated Rate of Return
This is a rate of return on the supply of assets developed by the regulator, and is based on the financial structure of a network which the regulator considers is appropriate for providing regulated services

Reserve Trader
This is an action by the NEM operator (NEMMCo) to contract directly for electricity supply from some electricity generators not usually providing electricity into the NEM, and/or with some consumers to reduce their usage at the demand of NEMMCo

Revenue This is the amount of money paid to the network by users

Revenue cap
See appendix 2

Tariff The rate at which a network charges for its services. This could be based on $/time, $/kW, $/kWh or a combination of these

TFP Total factor productivity: See appendix 4

RAB Regulatory asset base: This is a value a regulator places on the network provided

WACC Weighted average cost of capital. This is the cost a network has to pay for the use of money. It is the return the network needs on its combination of debt and equity. It is referred to as the return <u>on</u> assets

APPENDIX 12

TEC Terms of Reference

"Price Caps, Total Productivity Factor, Building Blocks or Revenue Caps - which better encourages more efficient use of electricity in the long term interests of consumers?"

1. Project Background

Different forms of regulation are now set to be used by the Australian Energy Regulator (AER) across the NEM without robust discussion about the relative benefits of the various methods. The patchwork approach has arisen as a result of stakeholder pressure and jurisdictional preferences, not necessarily because different forms match geographical markets.

A patchwork approach exists across the NEM. For example:

- while transmission networks continue to operate under revenue caps, the National Electricity Rules give jurisdictional regulators the option to choose either revenue or price caps, or a hybrid model for distribution networks;

- in NSW, the IPART 2004/05 determination abandoned the revenue cap in favour of a price cap, but put in place the 'D-factor' incentive for demand management;

- while Queensland currently retains a revenue cap, the next determination will test the new 'propose and respond' approach;

- in Victoria there is a strong push for the total productivity factor (TPF) approach to setting price caps for the upcoming determination, despite revenue caps being in place for transmission networks.

There has been no rigorous assessment of the outcomes of these forms of regulation, particularly in relation to efficiency in the use of electricity and the resulting impacts on consumers. In particular, no comprehensive analysis of the relative benefits of price cap (with or without TPF) versus revenue cap regulation has been undertaken since 1994[46]. As a result, the capacity of consumer groups to understand and contribute to decisions in the application of the various regulatory options is limited.

Incentives for demand management (DM) are a focus of this project. Current investment in network services is highly inefficient, as network augmentations are usually built to service peak demand that occurs for only a few hours of the year. It is likely that a move to price cap regulation for distribution networks will worsen this situation.

Recent proposals at the national level for regulation of distribution networks have tended towards a less precise regulatory climate where the Australian Energy Regulator, in

46 Government Pricing Tribunal (now IPART), *Price Regulation and Demand Management*, September 1994.

consultation with the distribution network service provider (DNSP), will determine what form of economic regulation to apply in each case ('propose and respond').47 In the many issues papers of the last two years there has been a general assumption that revenue caps are not appropriate for DNSPs, but there has been minimal evidence presented for that assumption. This project aims to clarify and contrast the benefits for consumers.

2. Project Summary

This project will increase the capacity of consumer groups to understand and critique the various regulatory approaches. The project will assess the relative benefits of price caps (including TPF) and revenue caps, taking into consideration the goals of the participating groups and the range of matters that the AER must consider, including:

1. Which mechanism better encourages more efficient use of electricity, impacts on demand management, end user consumption and prices, and the balance between network costs and revenue?

2. What incentive schemes are possible under the mechanisms to encourage demand management?

3. Which mechanism better caters for the needs of vulnerable consumers?

4. What incentive schemes are possible under the mechanisms that will reward network companies for reducing the number and duration of outages that have a market impact, and for providing more advanced notice of outages?

5. What mechanism best delivers the new revenue and pricing principles recently introduced to the National Electricity Law, including:

    a. "A network should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in its operations"

    b. "A network should be given effective incentives to promote the economically efficient investment in and provision and use of network services"

    c. "The regulator must have regard to the regulatory asset base adopted in previous determinations"

    d. "The prices and charges for regulated services allow for a return commensurate with the regulatory and commercial risks involved in providing the services"

    e. "That the regulator has regard to the economic costs and risks of the potential for under or over investment by a network in its network"

[47] For example, the proposal presented in the MCE Electricity Amendments package, January 2007.

f. "The regulator has regard to the economic costs and risks of the potential for under or over utilisation of a service provider's network".

6. What other mechanisms and incentives may be needed to support either form of regulation to secure the best long-term interests of consumers?

The report will provide a timely contribution to current decision making as responsibility for regulatory functions is transferred from the jurisdictions to the new national bodies.

The forums, briefing notes and final report (see below) on the costs and benefits of price cap versus revenue cap regulation could be expected to directly influence the content of the National Electricity Rules, the approach to DM by the AEMC, and the regulatory approaches taken by the AER.

3. Detailed Project Description

3.1 Initial Scoping Forum

TEC will organise a facilitated, preliminary half-day forum, with participation from the consultant, the Major Energy Users Association Inc, the Consumer Action Law Centre, the Consumer Utilities Advocacy Centre and Total Environment Centre (TEC) to scope out the key issues of concern with regard to form of regulation. This forum will provide the focus for the rest of the project.

3.2 Briefing Notes

The consultant will produce a series of briefing notes on the key issues emanating from the initial scoping forum and pertaining to the form of regulation. The briefing notes will also address the range of matters the AER must consider. Briefing notes may include:

- Plain English overviews of the key forms of regulation
- Demand management in the context of price caps and revenue caps
- Implications for low income consumers of price caps and revenue caps
- Total productivity factor versus building block regulation and price caps
- Impacts of price caps and revenue caps on all other matters that the AER must consider (outlined in Section 2 above)

These will be distributed in draft form to a range of non-government groups representing NEM consumers 1 week prior to the following public forum.

3.3 Public Forum

TEC will organise a facilitated one day public forum for a wider range of non-government groups representing NEM consumers. This will also be attended by the consultant to flesh out the remaining issues and identify areas for additional research.

3.4 Final Report

The consultant will carry out additional research identified in the public forum and compile a draft report with recommendations for TEC's feedback, and then a final report. TEC will disseminate the report to relevant NEM participants.