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

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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.

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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.

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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
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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 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.)

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 and network losses. 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.

[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 four to five years in Australia. 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 invest 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. 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 performance 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, 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 the "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].

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

[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

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 IPART 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.

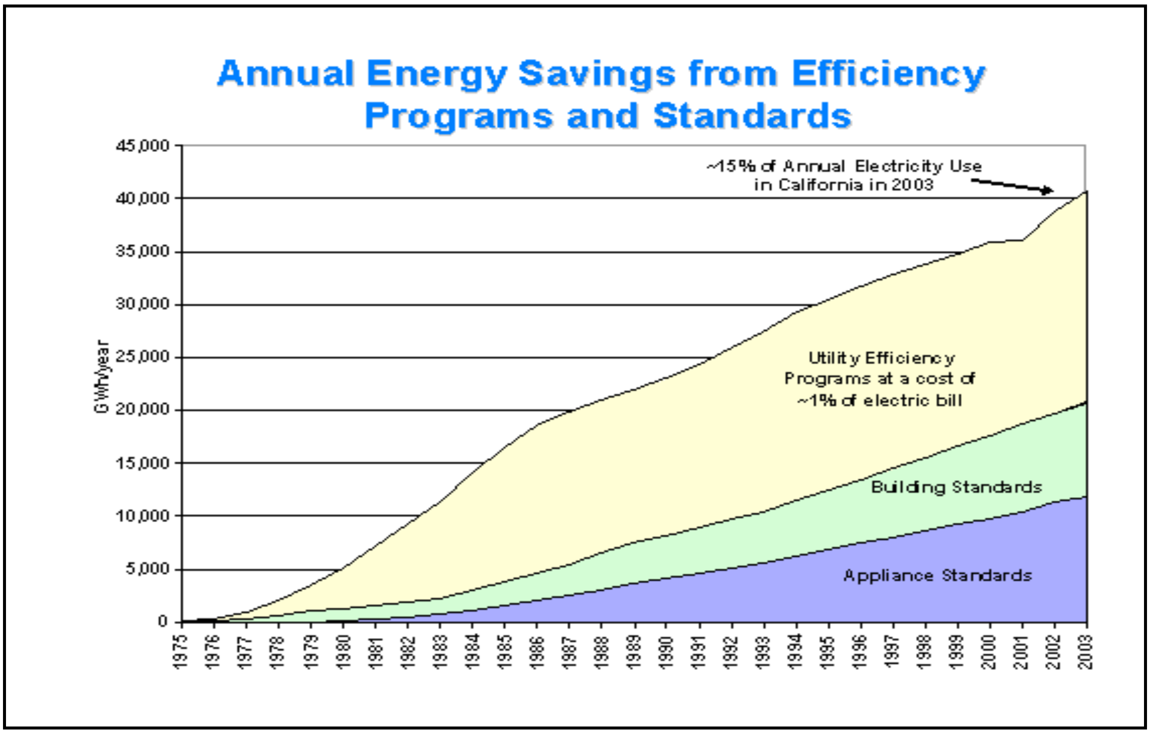
Another way of comparing is to consider per capita DM expenditure. In the US in 2004, utility funded energy efficiency DM programs in different states ranged from zero to in excess of $20 per person, with a national average of US$4.93 per person (equivalent to about AU$5.50 per person) (Eldridge, p.7). 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. 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.

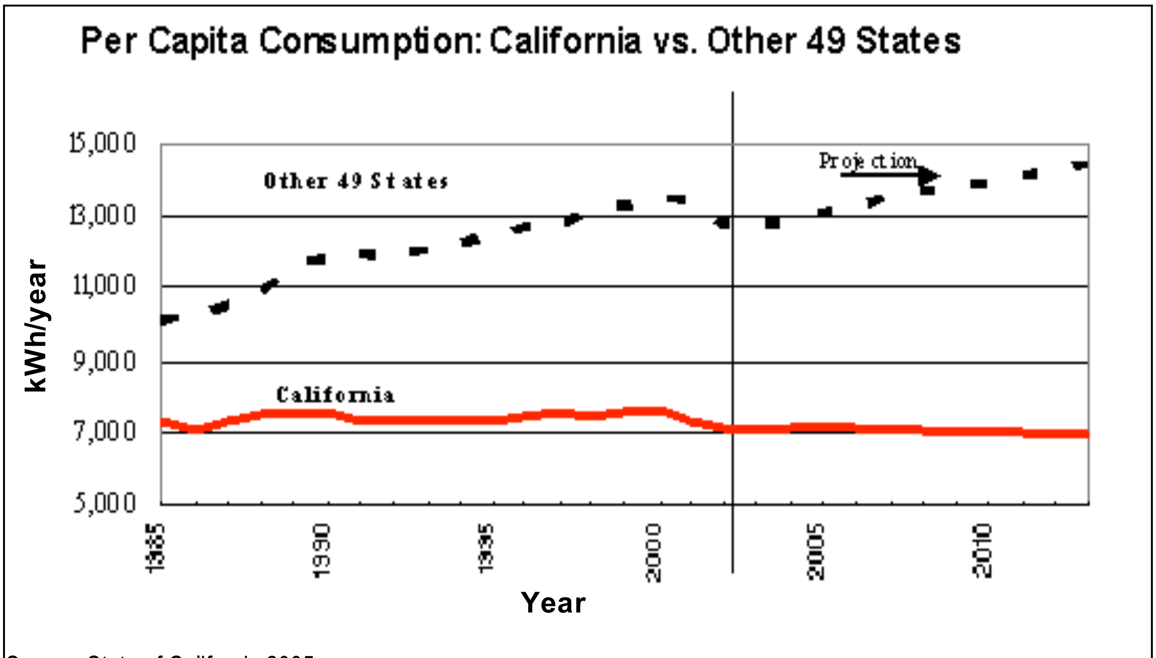
Figure 1



Source: (State of California 2005)

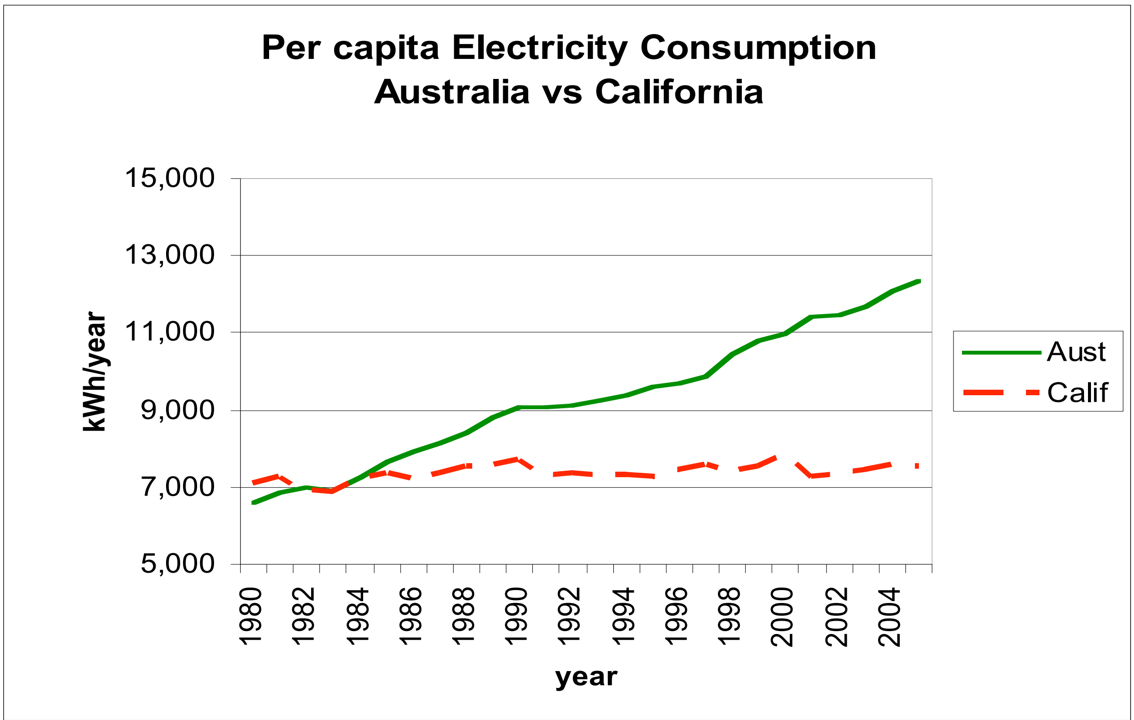
The effectiveness of DM in California is further highlighted by comparing the trends in per capita electricity consumption in California with those in the remaining 49 states of the USA (Figure 2). While electricity consumption in the rest of the USA (including several other states that have strong DM 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

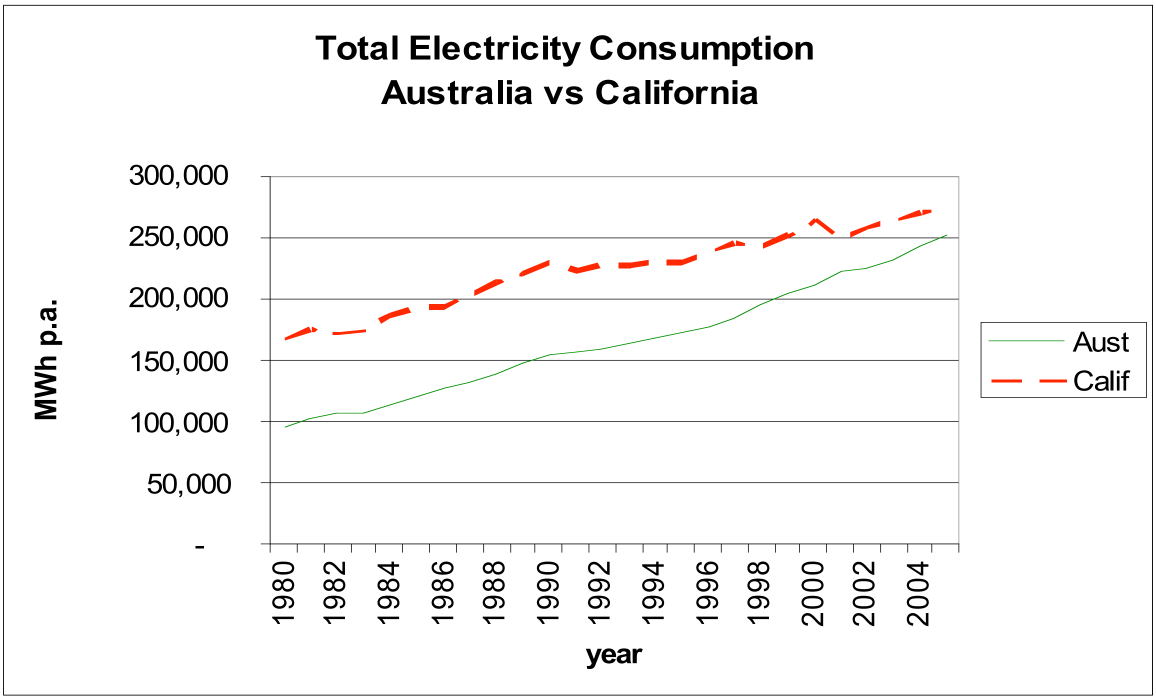


Sources: Australian Bureau of Statistics n.d.; California Energy Commission 2006; Real Estate Center 2006; Australian Bureau of Agricultural and Resource Economics 2006.

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. 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.

[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 7% 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, were 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 reported 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 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 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 submissions 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. Notwithstanding 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 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 cost 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 smart meters on 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 to 14).**

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 in Chapter 2.

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. The customer numbers 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". Linking to well-accepted indicators of economic activity such as Gross State Product is likely to be a more effective approach.

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 also be 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 be 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 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.**

To effect such balanced prudence reviews it is also essential that the Distributors are required to document and substantiate their efforts to procure cost effective 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 DM 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 DM 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 proposed amendments relate to the specific content of the Rules. They 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 described in Chapter 3.

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 d (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 relevant factor

6.5.8 Efficiency benefits sharing scheme

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.

6.5.7 Forecast capital expenditure

Insert in (a)

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

6.18.3 Pricing proposals

Insert in paragraph (b)

(9) describe how proposed tariffs will support cost-effective *demand management.*

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 Prudency and efficiency of capital expenditure

Insert after paragraph (7)

(8) 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].

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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.

The Tribunal's final decisions in relation to the treatment of 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**

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
	DESCRIPTION & STATUS							PROJECTED OUTCOMES					
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 and 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 $1.5m in NGACS
	Kogarah Town Square	Solar power- analysed potential	Local Generation	C									
		Load control - off-peak hot water	Load Shift	C			ongoing						
		efficiency awareness program	Energy Efficiency	C			initiated						
2003-04	**TOTALS**							**15,000**	**7,000**	**$ 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/Wolle	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**

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 load
		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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