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6 November 2007

Dr John Tamblyn
Chairman
Australian Energy Market Commission
Level 16
1 Margaret St
Sydney 2000

Dear Dr Tamblyn,

Rule change proposal – demand management and transmission networks

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

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

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

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

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

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

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

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

Yours faithfully,

Jeff Angel
Executive Director

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Rule Change Package

Demand management and transmission networks

6 November 2007

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

Contents

1 Introduction

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

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

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

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

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

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

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

[2] For example, *6.2.3(d)(2)*
[3] Commonwealth of Australia, *Towards a Truly National and Efficient Energy Market*, 2002, p 173
[4] Total Environment Centre, Consumer Utilities Advocacy Centre, Business Council for Sustainable Energy, Australian Council of Social Services, WWF Australia, Australian Conservation Foundation, St Vincent de Paul Society, *Power for the People Declaration*, May 2007 at www.tec.org.au
[5] Total Environment Centre, Council of Social Services NSW, Queensland Consumers Association, WWF Australia, Conservation Council of South Australia, Climate Action Network Australia, Environmental Defenders Office NSW, Environment Victoria, ACT Council of Social Services, Alternative Technology Association, South Australian Council of Social Services, Australian Conservation Foundation, Moreland Energy Foundation, Public Interest Advocacy Centre, Nature Conservation Council of NSW, Tasmanian Council of Social Services, Tasmanian Environment Centre, Consumer Law Centre of Victoria, Queensland Conservation Council, Consumers Federation of Australia, *The National Electricity Market Amendment Package*, October 2004, at www.tec.org.au

2 Other NEM processes to address DM

2.1 DM as a Jurisdictional Direction

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

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

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

2.2 The Renewable and Distributed Generation Working Group

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

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

2.3 The Smart Meter Working Group

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

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

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

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

2.4 Regulatory Test

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

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

2.5 New distribution Rules

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

2.6 New National Energy Market Operator

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

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

2.7 AEMC's Review of Demand Management

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

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

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

3 Background

3.1 Benefits of demand management

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

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

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

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

Efficiency

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

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

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

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

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

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

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

Reliability

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

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

Long-term interest of consumers

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

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

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

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

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

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

The potential for DM in the NEM

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

3.2 Barriers to demand management

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

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

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

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

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

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

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

Planning

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

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

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

Information

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

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

Regulation

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

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

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

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

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

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

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

3.3 Existing Rules content

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4 Rule proposals

4.1 General problems relevant to all following Rule change proposals

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

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

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

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

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

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

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

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

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

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

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

4.2 General solutions relevant to all following Rule change proposals

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

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

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

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

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

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

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

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

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

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

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

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

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

4.3.1 Efficiency

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.3.2 Reliability

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

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

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

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

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

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

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

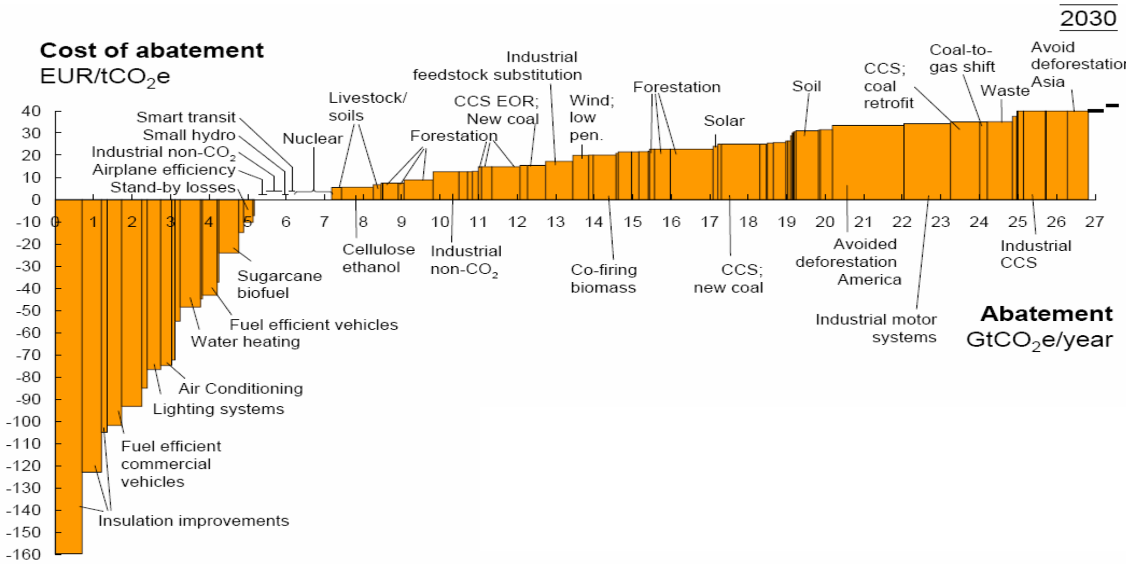
4.3.3 Greenhouse emissions, carbon costs and broader economic impacts

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

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

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

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



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

4.4 Transmission network planning

4.4.1 The problem

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

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

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

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

4.4.2 The solution

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

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

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

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

4.4.3 Proposed Rule changes

Change 5.6.2 (c) to:

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

Change current 5.6.2 (e) to:

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

Insert after 5.6.2 (e)

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

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

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

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

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

Change current 5.6.2 (f) to:

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

Change current 5.6.2 (g) to:

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

Change current 5.6.2 (h) to:

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

Insert after current 5.6.2 (h):

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

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

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

(3) summarises the submissions from the consultations; and

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

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

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

(1) includes assessment of all identified options;

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

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

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

(3) summarises the submissions from the consultations; and

(4) recommends the action to be taken.

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

4.4.4 How this proposal meets the NEM Objective

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

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

4.5 Annual Planning Reports

4.5.1 The problem

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

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

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

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

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

4.5.2 The solution

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

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

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

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

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

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

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

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

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

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

4.5.3 Proposed Rule changes

Change 5.6.2A (b) (3) to:

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

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

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

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

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

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

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

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

Insert after 5.6.2A (b) (4):

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

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

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

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

(iv) total cost of the proposed solution;

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

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

Change 5.6.2A (b) (5) to:

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

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

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

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

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

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

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

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

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

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

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

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

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

4.5.4 How this proposal meets the NEM Objective

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

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

4.6 DM Incentive

4.6.1 The problem

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

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

4.6.2 The solution

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

4.6.3 Rule change proposal

Insert after 6A.7.4:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.6.5 How this proposal meets the NEM Objective

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

4.7 Financial cover for DM investments

4.7.1 The problem

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

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

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

4.7.2 The solution

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

4.7.3 Proposed Rule changes

Insert after 6A.2.2

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

Insert after 6A.4.2 (4)

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

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

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

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

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

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

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

4.7.4 How this proposal meets the NEM Objective

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

4.8 Revenue determinations

4.8.1 The problem

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

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

4.8.2 The solution

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

4.8.3 Proposed Rule changes

Insert after 6A.6.6 (a)

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

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

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

Insert after 6A.6.7 (a)

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

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

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

Insert after S6A.1.1 (3)

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

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

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

Insert after S6A.1.2 (1)

(x) all demand side activities

Insert after S6A.1.2 (1) (iii)

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

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

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

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

Change 6A.14.1 to:

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

4.8.4 How this proposal meets the NEM Objective

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

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

4.9 Acknowledgment of modest DM expenditure

4.9.1 The problem

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

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

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

4.9.2 The solution

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

4.9.3 Proposed Rule changes

Insert after 5.6.5A (c) (8):

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

4.9.4 How this proposal meets the NEM Objective

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

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

4.10 Effective prudency reviews

4.10.1 The problem

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

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

4.10.2 The solution

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

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

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

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

[41] For example, Mountain Associates for ACCC, *An assessment of the prudency of TransGrid's investment in the MetroGrid project*, April 2004.
[42] Next Energy and Total Environment Centre, *Demand Management and the National Electricity Market,* February 2004, p. 19.
[43] ACCC, *NSW and ACT Transmission Network Revenue Cap TransGrid 2004/5 to 2008/9: Final Decision,* 27 April 2005, p. 88

4.10.3 Proposed Rule changes

Insert after S6A.2.2 (6)

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

(i) the implementation cost of the *demand side activity;*
(ii) the annualised value of the avoided augmentation alternative including:
(a) the capital costs;
(b) annual operating cost;
(c) the total annual net cost of servicing capital expenditure, including financing charges and capital depreciation;

(iii) the long term benefits of the *demand side activity* in terms of its contribution to the deferral or avoidance of other network augmentations;
(iv) the short and long term reliability benefits of the *demand side activity.*

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

4.10.4 How this proposal meets the NEM Objective

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

4.11 Regulatory Test

4.11.1 The problem

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

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

4.11.2 The solution

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

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

4.11.3 Proposed Rule changes

Change 5.6.5A to:

5.6.5A Regulatory Test

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

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

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

Change 5.6.5A (c) (1) to:

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

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

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

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

Change 5.6.5A (c) (3) to:

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

(i) cost-reflective pricing, including dynamic pricing
(ii) other demand side activities including
(~~i~~iii) energy source;
(~~ii~~iv) technology;
(~~iii~~v) ownership;
(~~iv~~vi) the extent to which the ~~*new network investment*~~*demand side option* or the ~~non~~ *new network investment* alternative enables *intra-regional* or *inter-regional* trading of electricity;
(vii) whether it is a *demand side, network* or non-*network* alternative;
(viii) whether the *demand side option, new network investment* or non-*network* alternative is intended to be regulated; or
(~~vi~~ix) any other factor;

Change 5.6.5A (c) (4) to:

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

(i) cost-reflective pricing, including dynamic pricing

and issue:

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

(a) consult with interested parties;
(b) explore the potential for interested party provision of demand side options

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

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

Change 5.6.5A (c) (5) to:

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

Change 5.6.5A (c) (6) to:

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

Change 5.6.5A (c) (8) to:

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

4.11.4 How this proposal meets the NEM Objective

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

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

4.12 Short-term and long-term price for DM

4.12.1 The problem

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

4.12.2 The solution

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

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

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

The Energy Users Association of Australia also support DSR:

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

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

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[44] Energy Response, *Response to the AEMC Reliability Panel Comprehensive Reliability Review*, 30 June 2006, p. 4
[45] Energy Response, *Response to the AEMC Reliability Panel Comprehensive Reliability Review*, 30 June 2006, p. 2
[46] Energy Users Association of Australia, *Press Release: New report confirms economic benefits to end users of demand side response (DSR) in the electricity market*, 21 October 2005, p. 3

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

4.12.3 Proposed Rule changes

Insert above 3.1.4 (a):

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

Change 3.2.2 to:

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

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

4.12.4 How this proposal meets the NEM Objective

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

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

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

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

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

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

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

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

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

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