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SUBMISSION

Public Consultation on a National Framework for Energy Distribution and Retail Regulation

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Section 1 - Introduction

1.1 Summary of recommendations

Total Environment Centre's major recommendations for the distribution and retail functions are based on support for a genuinely national electricity market and include, in summary:

1. Demand management must be enshrined in the Rules as an over-riding objective of the NEM.
2. Distribution and retail services should be regulated at a national level as far as possible; too much in the G&T/NERA proposal is left up to the jurisdictions. In the interests of consistency, certainty, equity and transparency, best-practice minimum requirements must apply across the NEM for it to be a genuinely national system.
3. Environmental and customer service obligations need to be addressed in a whole-of-system fashion. These are currently fragmented across the NEM, and the long-term interests of consumers would be better served by a consistent, structured approach.
4. Distribution and transmission regulation should be based on revenue capping, not price capping.
5. The Rules should refer to a Demand Management Code of Practice for distribution and transmission networks, with the NSW model to be adopted as a minimum (including the protocol for disclosure of information); networks to be obligated to implement non-network solutions where more cost effective than augmentation.
6. Generous incentives to encourage cost-effective network DM should be developed. DNSPs should be required to earmark a specific minimum spending level for DM: between 10% and 25% of the projected network capital expenditure should be set aside for cost-effective DM projects, on "use it or lose it" terms.
7. The Rules should refer to Retail Codes of Practice, with the Victorian *Energy Retail Code* and their *Code of Conduct for Marketing Retail Energy in Victoria* to be adopted as minimums.
8. Licensing of DNSPs and retailers should be retained and elevated to the national level.
9. Barriers to the connection of embedded generators must be removed and preference given to such generators over augmentation of the networks.
10. Where an alternative energy source/generator is being proposed (non fossil fuel, for instance) and substantial network augmentation is necessary, alternative arrangements should be made at a national level for funding the augmentation rather than the network service provider or the generator footing the bill.
11. Advanced interval meters should be installed across the NEM, with the rollout beginning by 2007. The benefits are sufficiently clear to justify the costs.
12. A standardised scheme should be developed for tariffs across the NEM to allow for time-of-use pricing and transparency of pricing. The details could be tailored to meet local demand/climatic conditions.

13. A standardised minimum format regarding criteria for information to be presented in customer accounts needs to be developed and referred to in the Rules.
14. A National Energy Savings Fund should be established, with a start-up of $700 million over 5 years as a minimum.

1.2 Introduction

1.2.1 Key themes

Total Environment Centre welcomes the opportunity for further input to the Review of a National Framework for Energy Distribution and Retail Regulation. This submission builds on our previous response to "Proposed Framework Schedule for Transfer of Distribution and Retail Functions" (November 2005). We have addressed many of the issues framed within the paper titled "Public Consultation on a National Framework for Energy Distribution and Retail Regulation", produced by Gilbert + Tobin and NERA Economic Consulting (hereafter referred to as the G&T/NERA paper) on the basis of our particular concerns, specifically on electricity (that is, excluding gas). We have focused on the key objectives identified by the Ministerial Council on Energy as identified in the G&T/NERA paper (p1):

> *(a) provide national oversight and coordination of policy developments to address the opportunities and challenges facing Australia's energy sector; and*
>
> *(b) to provide national leadership so that consideration of broader convergence issues and* ***environmental impacts*** *are effectively integrated into energy sector decision making.* [our emphasis]

Total Environment Centre (TEC) further endorses the overall notion of a national framework of legislation, but we have some concerns about the role of the jurisdictions as outlined in the paper (see Section 2, D.9). Of particular concern to TEC is the treatment of demand management in the National Electricity Market (the NEM), and Section 1.2.2 contains a discussion of this issue.

TEC's main recommendation is that in a national system it is essential that there be a **genuine** common regulatory framework that avoids the lowest common denominator. As many details as possible should be dealt with at the national level within the National Electricity Rules (the Rules) to a high standard, partly because in a competitive system companies will have interests across the jurisdictions, but there is also the necessity for a system that is best practice for all Australians. To promote transparency, clarity and equity it is critical that there be a uniform system with clear provisions and prescriptions. The major proviso here is that any demand-side and environmental gains made at the jurisdictional level not be lost in the move up to a national level, but instead should be enhanced.

To ensure transparency and certainty, there needs to be consistent application of principles to decisions. This is not only reassuring for consumers but also respects the needs of business. It is preferable to go through the process of a formal Rule change, with all its checks and balances, where the matter is deemed sufficiently significant. This would increase the level of accessibility and public involvement in key regulatory decision making. Although the current system as a whole is already fairly prescriptive, there remain significant barriers to non-network solutions and the wider entry of embedded generation and renewable energy technologies.

It is not sufficient to leave major decisions about issues of distribution and retail of electricity to the AER's discretion as this can lead to greater inconsistency. The Rules have been established as a substantial and sophisticated set of directions for the NEM; it would be an oversight not to include distribution and retail matters within their ambit, with details set out as far as is practicable. Transmission Network Service Providers (TNSPs) and Distribution Network Service Providers (DNSPs), in part due to the scale of the investment necessary, form natural monopolies and are thus anti-competitive in essence. This is contrary to the spirit of the NEM, and therefore to reduce regulation of the network services would allow the further entrenchment of their inefficient monopoly behaviours. Retail businesses form the interface between the consumer and the rest of the system and therefore equally need detailed consideration at the national level, by the AER.

Energy policy experts have asserted the need for regulation in a changing system dealing with an essential service, particularly where markets do not necessarily provide sufficient social benefit[1]:

> *Reasons for such market failure can include monopolies and the failure of competition, the need to provide essential public goods, incomplete markets, information failures, boom-bust business cycles and market externalities. Energy markets appear to be at risk of market failure for all the above reasons, as they often exhibit:*
>
> - *natural monopolies in at least some network provision, and a generally concentrated supply side,*
> - *a vital role in providing essential public services, and contributing to wider societal objectives such as economic growth,*
> - *dysfunctional interactions with some other important markets due to uncoordinated decision making,*
> - *information failures, particularly on the demand-side where many end-users are poorly informed,*
> - *capital intensive and long lived assets that can lead to cycles of over and under-investment, and*
> - *very significant environmental externalities, particularly from the GHG emissions that arise from the use of fossil-fuels.*

To allow flexibility in decision making and take account of changing technology and expectations, it is possible to establish enforceable Codes of Practices. These can be embedded into the Rules as legislative requirements, with the ability to change the actual contents of the Codes more readily. Similarly a national system of licensing DNSPs and retailers to ensure consistency across jurisdictions should be established, again with the potential for more rapid alteration of the provisions of the licence conditions. The G&T/NERA paper argues for the abolition of licensing systems, but licensing provides too many benefits to be scrapped (see also Section D.2 below).

National mechanisms to promote demand management and energy efficiency can also be developed. TEC recommends the establishment and funding of a National Energy Savings Fund. The NSW Government has instituted such a fund for its own jurisdiction, for $200

[1] MacGill, I, Outhred, H, & Nolles, K, "Some design lessons from market-based greenhouse gas regulation in the restructured Australian electricity industry", *Energy Policy 34,* p 11

million over 5 years, with the prospect of continuance into the future. The Fund is expected to deliver savings of 900,000 MWh per year while saving consumers a total of $370 million on their electricity bills. This will be achieved by providing direct incentives for energy savings while stimulating the embryonic energy savings provider industry.

Similar Funds exist in over 25 states in the USA, resulting in more efficient electricity systems by avoiding inefficient network and generation augmentations. Such a Fund should be considered at the national level in Australia, with $700 million – a small proportion of expected infrastructure investment due to spiralling demand – set aside over 5 years as a start.

1.2.2 Managing electricity demand

Demand management[2] (DM) for electricity can deliver many benefits towards promoting an efficient NEM and meeting the long-term interests of consumers. It must therefore be promoted from a subsidiary consideration to one of national importance. DM should be recognised as a superior alternative to augmentation by the AEMC, the AER, the TNSPs and the DNSPs because of the massive benefits that it delivers to consumers. Similarly, retailers must be directed to promote energy efficiency measures. With the system in a state of flux, now is the time to set the foundation for the future.

Economic efficiency is central to the NEM. To achieve this there must be equal emphasis on demand and supply as the basis of standard economic regulation. DM and energy efficiency must therefore be given high priority and be integrated in uniform national regulation.

At the national level, DM has been accorded significance but little has been done to implement it in practice. For instance, at the second NEM Ministers Forum in 2001, it was stated that, "Attending Ministers recognised that the prospects for a more active role in the NEM for demand side initiatives had not been fully investigated. It was agreed to develop a more comprehensive understanding of the potential for demand side management and participation in the NEM, and to identify potential impediments to the emergence of efficient and innovative forms of demand side participation within the NEM." Yet this intent has not been activated.

The Energy Networks Association described demand management approaches[3] as including load management measures; distributed generation; power factor correction; and fuel substitution. They noted that these, “approaches may provide alternatives to increased energy supply or augmentation, through shifting or reducing customer demand, actions that alter the level or pattern of energy consumption, the energy source, or the use of the distribution network.” The ENA also pointed out that there is an emerging market for demand management.

[2] Demand management (DM) in this submission can be read to include the broad range of demand management measures, including ‘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 most cost effectively. 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. In the G&T/NERA paper, terms are used variably such as both “demand-side management” and “demand management”: the former may be a subset of the latter.

[3] Energy Networks Association, *Submission to the Productivity Commission: Energy Efficiency – Response to Draft Report*, 27 May 2005, p 4

There is a heavy reliance on large coal-fired generators in much of Australia, with coal representing 42% of total primary energy consumption in 2003-04 (mainly used to generate electricity).[4] This consumption creates enormous environmental impacts, which DM can go some way to alleviating.

DM can offer many benefits, for instance:

> *Electricity … provides a great opportunity for better efficiency, resource economy and enhanced environmental outcomes from the inherent possibilities for investment and other measures on the demand side. … In the present state of the NEM, scarcity of capacity generally arises from the decision to cater for peak demands by using the most expensively priced plant. The peak demand could, of course, be managed by reducing it. … DM and EE measures may require relatively small amounts of capital investment, and some require none at all, but are sometimes more, and often very much more, efficient than supply side investments.*[5]

The Energy Users Association of Australia gave some suggestions for the benefits of a properly functioning demand-side response sector in the NEM[6]:

- *A more predictable, stable, and efficient electricity market by facilitating a demand side response;*
- *A lower risk to the security of the interconnected power system;*
- *A lower cost of hedges and managing risk by market participants …*
- *An improved asset utilisation across the electricity system (NSPs and generators will gain an improvement due to flatter load profile and this should be reflected in lower regulated fees over time);*
- *Improvements in market liquidity; and*
- *Some energy conservation in response to high prices reduces emissions due to a reduction in network losses and more efficient use of existing base load generators, as well as in promoting the increased use of energy efficiency.*

In terms of benefits, Energy SA gave a summary of those DM may provide[7]:

- *Reduce wholesale and consumer electricity prices*
- *Improve system reliability*
- *Reduce the likelihood of blackouts*
- *Postpone or avoid infrastructure development and associated costs*
- *Reduce greenhouse gas emissions*
- *Improve the competitiveness of South Australian* [and Australian] *businesses*
- *Open up new opportunities for energy management services*

[4] Australian Bureau of Agricultural and Resource Economics (ABARE), *Energy Update, 2005 – Australian energy consumption and production, 1973-74 to 2003-04,* June 2005, p 3
[5] McDonell, G, *COAG's Quandary: What to do with the Energy Markets Reform Program?* February 2005, p 18
[6] Fraser, R, *Demand Side Response in the National Electricity Market – Case Studies*, Energy Users Association of Australia, 2005, p 26
[7] Energy SA, *Demand Side Management: Benefits to Industry & the Community*, October 2001, p 14

The lack of incentive mechanisms for the implementation of non-network solutions is resulting in inefficient, peak-demand driven transmission and distribution network infrastructure investments. Incentive mechanisms for DM are needed to counter the inappropriate and inefficient focus on the supply-side of energy service provision in the NEM. There are incentives that can be offered to networks to implement non-network solutions.

The most important solutions for establishing a robust demand-side presence in the electricity market – and which must be given proper consideration in this review – include:

- establish a DM funding mechanism
- establish a DM code of practice
- ensure networks investigate and implement DM as an alternative to network augmentation where cost effective
- establish incentives throughout the NEM for the implementation of DM and the use of small, local generators based on alternative energies
- ensure networks disclose information on impending constraints in a timely manner
- transparency of pricing in relation to demand and constraints – end users are currently unaware of the true price of their electricity
- enable genuine open access for embedded generation and alternative energies.

Section 2 – Specific responses

Part B: Price regulation of distribution

B.2. The scope of distribution price regulation

TEC does not object to the general principle that, "The scope of distribution price regulation should be determined on a national basis, across all jurisdictions." (p 13) We also agree with the key principles overall, with the notable exception of price cap regulation (see next section). In addition, the current scope of distribution price regulation inappropriately excludes demand management from its considerations. DM in all its forms must be considered equally alongside augmentation options in the regulation of distribution pricing.

The paper is also equivocal about whether DNSPs form a natural monopoly or not and whether effective competition can be established. This is a fundamental factor on which to base regulation, and needs to be clearly established. It is evident that, in practice, the networks do indeed form natural monopolies. The network system is capital intensive and only a limited number of companies can effectively approach setting up or buying into such businesses. DNSPs should be regulated in the way that TNSPs are, on the basis that they form natural monopolies while performing an essential service.

B.3. Price cap regulation for distribution services

Revenue cap versus price cap

TEC reiterates our preference for a revenue cap with the facility for a set-aside percentage for demand management. A revenue cap provides greater incentive for

consideration of non-network solutions since the network can absorb the savings, while allowing for flexibility in pricing. A price cap form, in contrast, rewards networks for more electricity sales, and does not impose limitations on network augmentations even when more cost-effective alternatives are available. A revenue cap also encourages prudent investment. Without such a cap, networks have a reduced incentive to carry out their operations within budget, and could instead seek to make up for shortfalls by encouraging greater consumption of electricity.

Some of the disadvantages of price capping have been explained by electricity industry expert, Gavan McDonell[8]:

> One of the most deficient aspects of price cap regulation is that it *provides the incentives to increase the transport of energy through the grid,* since the greater the quantity of energy moved, the greater the revenue and hence the opportunity for profits. That is, *this system of regulation provides direct incentives both to increase industry's economic costs* and *to encourage greater household demand.*

As a second preference, any price cap system must include incentives for DM to counter the massive inducements and cultural bias for DNSPs to sell more electricity. Such incentives should ensure that networks are able to recoup revenue for both the cost of carrying out demand management and for the lost revenue of sales that would have been made had an augmentation gone ahead. This generous incentive is particularly necessary to counter the current 'build' culture within the networks and the under-developed energy savings provider industry. This form of incentive also recognises the positive externalities of network DM, such as reduced greenhouse emissions and hence in the costs associated with them.

There is a useful model in NSW, the "D-factor", which is intended to promote DM by networks through the use of incentives on condition that, "the DNSPs must demonstrate to the Tribunal [IPART] that its demand management implementation costs are less or equal to the avoided distribution costs before it can pass through any costs to customers."[9] The mechanism allows DNSPs to recover:

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

Form of regulation

In addition, one form of regulation should be selected and specified in the Rules. To allow for a range of choices – with the implementation of choice to be left to the AER – is to continue the uncertainty of operating across jurisdictions. The G&T/NERA paper have left this subject open, stating only that, "the Rules should specify one or more forms of price regulation (eg, building blocks, tender process). Where the Rules allow for more than one form of regulation, the Rules should also set out the circumstances in which the AER is to

[8] McDonell, G, *COAG's Quandary: What to do with the Energy Markets Reform Program?* February 2005, p 35 (his emphasis)
[9] IPART, *Guidelines on the Application of the D-factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination*, April 2005, p 1

adopt each of the forms specified." (p 19) This recommendation does nothing to clarify or streamline regulation.

Within a common regulatory framework all services, from generator down to retailer, need to be regulated, including in regards to revenue and pricing. Regulation of revenue and pricing need not adversely affect the intended competitive nature of the NEM, rather, it would strengthen it by enabling a more dynamic market with equal emphasis on supply and demand. Without such regulation, consumers would be at the mercy of a supply-focused, monopoly system, with massive incentives to sell electricity and no demand-side market to provide alternatives to wasteful and inefficient consumption.

In terms of the form of regulation, we support a revenue cap applying the CPI-X building block approach to maximum allowable revenue. The Public Interest Advocacy Centre have argued succinctly for the retention of the building blocks methodology: "The building blocks approach ... is an approach which consumers have come to accept and support. The reasons for any change need to be argued clearly. ... the building block approach offers regulatory certainty both to the regulated entities and end-users."[10] They add that other methods, "are lacking in transparency".

Promotion of DM

There is currently a lack of clarity from regulators regarding the recovery of DM spending, which creates uncertainty for networks considering DM solutions to constraints. The national regulator should therefore clearly set out the circumstances in which networks can recover the costs of implementing DM. For instance, as suggested in the G&T/NERA paper, "(ii) In assessing additions to the capital base for prudency, the regulator may consider the extent to which the distributor has taken into account appropriate alternatives to network augmentation (eg, for electricity this may include DSM measures)." (p 22) However, if the regulator expects networks to take DM seriously, it needs to undertake a meaningful and substantiated assessment of past network investment and disallow recovery of imprudent investment that should have been deferred.

Currently, DNSPs are not obligated to solicit proposals for alternative non-network solutions before expansion of their networks. This creates a natural barrier for cost-effective non-network solutions and forecloses on the potential for DNSPs to operate more efficiently by avoiding unnecessary or premature augmentations, and thereby create savings for consumers. Instead, DNSPs should be required to investigate non-network solutions and implement them where cost effective. To facilitate this process, the AEMC and the AER should promote a comprehensive approach through mandatory DM codes of practice (see also Section B.9), including clear protocols for information disclosure, specification of constraints, requests for proposals, and evaluation of proposals. TEC supports the G&T/NERA recommendation (p 23):

> *Allowing the AER to take into account the extent to which the distributor has considered alternatives to network augmentation as part of the AER's assessment of the prudency of the investment, represents a more appropriate means of ensuring that non-network alternatives are considered where relevant.*

[10] Public Interest Advocacy Centre, *Submission on Transmission Revenue Requirements: Issues Paper,* November 2005

However, as stated above, this must be backed up by the disallowal by the regulator of imprudent investment that should have been deferred.

B.4. Regulatory requirements in relation to tariff setting

Need for national regulation

TEC does not object to tariff setting principles being established nationally, within a national system, as the paper recommends. However, they must reflect the true costs of the system – that is, the effect of constraints and peak demand. There needs to be transparency of costs throughout the system including at the distribution network level. This will be particularly important when interval metering becomes an established feature. Tariffs will then need to be related to the time of use of the network, since this affects the actual cost.

Regarding policy criteria point (i) regarding regulations for tariff setting, not only economic criteria but also customer benefit criteria should be considered. Both can be met within the NEM, and meeting customer interests may have economic benefits that are not immediately obvious. The market is to be used by customers, not just industry providers, and they will not always operate solely according to economic criteria. It diminishes the efficiency of the market if only economic criteria are factored in without considering environmental and social criteria. This emphasis is particularly suspect in a market which includes such powerful monopoly sectors, and long-term consumer interests are intrinsic to the National Electricity Law (NEL) Objective.

Cost-reflective tariffs

In general tariffs across the NEM do not accurately reflect actual costs. Where there are discounts operating, they are generally based on long-term contracts. By early 2005, it was estimated that:

> *lower prices have little to do with price competition in the wholesale market. Many small businesses remain on the set tariffs. Most medium to large size businesses are now on negotiated contracts, though it appears that these also remain close in structure to the regulated tariffs. In fact, apart from some large customers, accounting for a small proportion of total energy use, the new `competitive' contracts are not responsive to time-of-use, and have set prices for specific levels of usage. Thus, the efficiencies which could arise from flexible pricing are lost.*[11]

Furthermore, McDonell argues that, "In practice, end-users are shielded from sharp moves in the pool price or even from the daily and seasonally repeated peak and off-peak price patterns ... This arises from the `smearing' that occurs of fixed costs and varying usage costs into prices, and by the absence of TOU or locational pricing." (p 28)

The Energy Network Association, has also noted that there is a lack of price signals within the NEM to the detriment of the whole market which time-of-use pricing could help address:

> *The lack of cost reflective pricing for many small energy users limits the pricing signals faced by consumers, thereby dulling incentives for consumers to invest in*

[11] McDonell, G, *COAG's Quandary: What to do with the Energy Markets Reform Program?* February 2005, p 28

> *energy efficient technologies or participate in demand management projects. Further, the lack of pricing signals where certain customers disproportionately contribute to peak energy load, in particular users of domestic air conditioners, also creates significant inefficiencies in the market through cross subsidies between users in the cost of network investment and peak energy to meet this demand. The ENA considers that the introduction of cost reflective time of use pricing is a critical issue for the future efficient development of the energy market, which is an outcome that would also provide improved signals for energy efficiency for all energy users*.[12]

A principle on time-of-use/cost-reflective tariffs needs to be inserted in the Rules, as well as a clear statement on the provision of up-to-date information (see also section D.6 Metering). Customers – whether residential, commercial or industrial – need to be informed of the variable costs of their electricity, and this will only happen if they are kept up-to-date with their usage and the associated cost. Advances in metering need to be in tandem with advances in pricing regimes. The jurisdictions can vary the actual tariff scales, but the overarching principles need to be instituted in the Rules.

It is essential that tariffs are linked to time of use by day, week and/or season within a simple tier system. Innovative tariff structures in other countries should be explored and developed for application in the Rules. In Sweden, for example, customers can choose packages which factor in peak prices – one is a fixed price, which can be changed to a new contract if the pool price drops significantly; another is variable, based on the price in the auction pool; or there is a capped tariff (above base load but below the known peak price)[13]. Such a tariff system can be arranged according to known price peaks, with this information to be spelled out in all communications between the DNSP/retailer and the consumer. It can be described in general terms rather than using complicated descriptions of the auction pool.

The roll-out of interval meters across Italy has led to the development of a tier system which includes reduced tariffs with clear definitions[14]:

- Level one – for those who have low usage (up to 1,000kWh pa)
- Level two – there is a reduction for use between 8pm and 7am during the week as well as weekends
- Evening tariff – reduction for usage in the evenings, between 7 pm and 1 am
- Weekend tariff – reduction for consumption on weekends.

The success of complex “plans” for phone use and Internet use demonstrates that many people will indeed shop around for a tariff system that suits their usage best.

Equally, adequate billing procedures would set out time of use and prices (see also C.1 Overview). Metering, billing and tariffs need not be overly complicated for those who prefer simplicity, since default/base rate systems can be provided as an option.

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[12] Energy Networks Association, *Submission to the Productivity Commission: Energy Efficiency – Response to Draft Report*, 27 May 2005, p 2
[13] Vattenfall, accessed online at http://www.vattenfall.se/privat/priser-och-avtal/el, on 25.10.2005
[14] Enel SPA, accessed online at http://www.enel.it/sportello-online/elettricita/tariffeelettriche, on 6.1.2006

Discounts

Principle (iv) about discounts is, in effect, referring to a form of stand-alone generation. The paper supports discounts on the basis that (p 29):

> *All customers are therefore better off if the customer remains connected to the network, rather than if it decides to build a stand-alone facility and bypass the network (in which case tariffs for remaining customers would rise). The principle says that a distributor is able to offer a discount to such customers in that circumstance, and to recover the cost of that discount by raising tariffs to other customers.*

Such discounts would work directly against both DM and DG, and TEC strongly opposes such a position. Stand-alone facilities should be encouraged as they reduce network congestion and avoid inefficient transmission and distribution losses through the delivery of electricity from remote generators to distant locations. The departure of a customer may temporarily increase costs for other customers, but in the long term it would lead to reduced costs, in particular because of avoiding future augmentation. Without that large customer, constraints are more likely to develop later rather than sooner. Providing discounts for customers to encourage them to remain connected contradicts the aim of efficiency across the NEM. If the NEM is failing to deliver appropriate services to a customer, it should be open to competition from alternative energy suppliers, including stand-alone generation. The only appropriate kind of allowable discounts should be for energy efficiency and time-of-use alternatives to avoid contributing to system congestion. This is a form of DM, the incentives for which have been outlined above.

Principle (v) about tariff equalisation is another example of divesting a difficult question to the jurisdictions. The national bodies need to make a decision as to whether tariff equalisation is required at a national level. To leave it to the jurisdictions is to again continue uncertainty within the system. If the jurisdictions wish to commit to a truly competitive market, then equalisation funds such as NSW's Electricity Tariff Equalisation Fund should be abolished. This would truly test the viability of attempting to transform a monopoly-based, essential service utility system into a genuine market.

B.7. Information disclosure

Disclosure of information is fundamental to transparency and certainty of decision making, and it relies not on quantity but quality. To date, lack of information has proved a significant barrier within the NEM, both in terms of accountability of the regulator and restriction of entry by competitors (such as DM providers and embedded generators). A transparent process will provide greater certainty for all stakeholders (regulator, DNSPs, retailers and consumers) as well as potential investors. DNSPs should also provide information on their expenditure on demand management, alongside opportunities they have investigated and the potential value of deferrals of augmentation.

A useful model here is the Disclosure Protocol from the NSW Demand Management Code of Practice[15]. The purpose of such a protocol is presented as:

[15] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice,* September 2004; the Disclosure Protocol is on pp 11-14

> *To inform the market in a timely manner, regular public reports on the status of the network are required. A standardised Disclosure Protocol is intended to ensure that distributors provide all necessary information in a clear and consistent form, without wasting effort in providing unnecessary information.*[16]

The protocol includes features such as planning guidelines, for describing the basis for load forecasts and describing the system planning guidelines. It includes pro forma spreadsheets, requests for maps and summary table requests to assist with clarity of presentation and so there is some standardisation of the information lodged.

South Australia also has a system of information disclosure, though at a lower level of detail than that for NSW. As part of Electricity Industry Guideline No. 12[17], ESCOSA requires ETSA Utilities to "regularly disclose information on possible network constraints", including the provisions that, "ETSA Utilities must publish an annual Electricity System Development Plan (ESDP). The ESDP must identify in detail any actual and forecast constraints on ETSA Utilities' network."

It is essential that all distribution businesses publicly provide clear information on areas facing constraints – or predicted to do so – in a reasonable timeframe (5, 10 and 15 years ahead) to allow DM providers to offer alternatives to augmentation. Lack of quality information can inhibit new entrants to the market.

The national regulator should also ensure that adequate financial information is delivered by distribution and retail businesses. The Rules need to refer to guidelines for reporting developed by the AER, regarding financial statements and applications for determinations. It is usually more effective for a business in terms of allocation of time to follow an existing set of guidelines than develop an application from scratch. It also provides other stakeholders with a more consistent set of data, making the information more available for comparison. We would support the G&T/NERA proposal (on p 36) that the Rules should:

> *(i) Provide that the AER can develop standard national Statements of Requirements for Regulatory Accounts, consistent across electricity and gas businesses; and*
>
> *(ii) Set out the circumstances in which the Statement of Requirements for Regulatory Accounts apply.*

As they suggest, these Statements would indeed, "streamline the current arrangements considerably, reducing compliance costs and improving the transparency and certainty surrounding the accuracy of the information used in the regulatory process. It will also enable the AER to have greater confidence in the comparison of information by distribution businesses across jurisdictions." (p 36)

[16] Department of Energy, Utilities and Sustainability, *Demand Management for Electricity Distributors – NSW Code of Practice,* September 2004, p 11
[17] Essential Services Commission of South Australia, *Demand Management for Electricity Distribution Networks*, *Industry Guideline No. 12*, September 2003, p 7

B.9. Distribution network expansion Rules

An efficient, cost-effective electricity supply system should make allowance for solutions other than those that rely entirely on network-driven solutions. Demand management in its various forms can be more cost effective, and hence more efficient, thus meeting the NEL objective. Non-network alternatives to expansion therefore should be given explicit consideration within the Rules. National regulation must ensure that demand management is fully investigated before the undertaking of network augmentation, and implemented where it is found to be more cost effective. This issue should be addressed in network expansion rules and in network planning rules, via a national demand management code of practice.

There are good reasons for deferring augmentation:

> *Because networks account for about 50% of electricity costs, and the bulk of those costs are fixed capital costs, numerous benefits follow if network investment can be decreased. … an immediate effect of obtaining energy efficiency and of managing demand is to reduce or defer network investment. The attractiveness of this is greatly enhanced in the present situation where peak demand is growing faster than energy sales.*[18]

NSW currently requires distribution networks to investigate and report on cost-effective non-network solutions to network constraints. The guidance for compliance with this licence condition is provided by the NSW Demand Management Code of Practice. South Australia too has developed a guideline for DM management, *Electricity Guideline No. 12*. A national code would involve clear protocols for information disclosure, specification of constraints, requests for proposals, and evaluation of proposals. The national regulator should improve on these requirements by ensuring that network monopolies investigate, report on ***and implement*** DM opportunities when they are more cost-effective than network augmentation.

Furthermore, recognising that transaction costs of participating in a Request For Proposal process would be very high for many small DM opportunities, the national code should promote standing offers for small DM services. It is unreasonable to expect that DM providers would be able to negotiate on equal terms with a large, monopoly network when offering network support. Standard offers specify the conditions for the provision of capacity in advance, and are usually made on a fixed price, take it or leave it, first come first served basis. It is recognised that DM providers can provide long-term network benefits, not only when the system constraint occurs.

One way of ensuring that networks undertake DM is for regulators to earmark a specific minimum spending level for DM by networks. Given the large technical and economic potential for DM, between 10% and 25% of the projected network capital expenditure should be specifically earmarked for cost-effective DM projects. This funding should be allowed only on "use it or lose it" terms, and could step up from an initial small percentage, increasing as networks become more adept at facilitating DM, then gradually reducing as the potential for DM is utilised.

[18] McDonell, G, *COAG's Quandary: What to do with the Energy Markets Reform Program?* February 2005, p 36

In a competitive market, the failure of networks to weigh up non-network and alternative generation options goes against the intentions of the National Electricity Law and adds unnecessary costs for consumers.

Part C: Consumer protection

C.1. Overview

Energy provision is an essential service, so safety net provisions with an obligation to supply are critical, to ensure that all customers have access to reliable electricity. There is limited scope for substitution for electrical power, and this needs to be given due consideration. To place such an obligation back on the jurisdictions could leave Australians in vulnerable situations open to exploitation, or even disconnection from any energy supply.

It is also essential to develop a consumer protection code at a national level that is specific to electricity provision. The approach presented by the G&T/NERA paper – although it professes to be a rationalisation of the current situation – is in fact still fairly fragmented, and once again leaves many too many decisions to the jurisdictions. It would be more consistent with the other forms of regulation being developed to elevate customer protection to a national objective. There would be no market without consumers, after all.

The *Energy Retail Code* developed in Victoria represents a minimum model which could be adapted for the national level. It should be noted that the primary dealings between an end user and an energy provider are via the retailer – it is rare for customers (except perhaps for some large industrial complexes) to have direct dealings with any business other than a retailer. On the whole it is the retailer who is the public face of the market, through negotiations about supply, conditions, products and billing. Therefore any references in the G&T/NERA paper to negotiations between distributors and customers have only limited application.

A national consumer protection code would include provisions for those matters addressed in Part C, that is:

- obligations to connect and supply
- obligations regarding disconnections and reconnections
- mechanisms for dispute resolution (which should be based on Australian Standard 4260 on Complaint Handling as a minimum)
- market contracts
- marketing (see also Section C.7 below).

Such a code would include a minimum standard for the matters to be addressed with billing. Bills issued to customers represent the only regular source of information on their participation in the NEM, and it is important that clear information is provided about tariffs and energy consumption. For instance, the Victorian *Energy Retail Code* specifies that bills should identify, “if the retailer directly passes through a network charge to the customer, the separate amount of the network charge;” and “the customer’s consumption for each billing period over the past 12 months.” Matters to be addressed in the minimum standard could include:

- TUOS charges
- DUOS charges
- clear descriptions of usage according to time of use and the associated tariffs
- comparison for each bill over the past 12 months for consumption plus either carbon dioxide emitted or the emissions avoided (for Green Power).

With the development of a new market, it is also critical to develop energy-specific regulation, rather than relying on the generic terms of reference of Fair Trading Acts and the *Trade Practices Act 1974* (Cth). General consumer protection legislation is insufficient in an atmosphere of such rapid change, where so many details of the new national system are still being designed. Moreover, there are features specific to energy provision which require attention, such as conditions relating to disconnection and supply. In the long run such energy-specific legislative mechanisms could be removed, but need to be developed at a national level for application during this period of flux.

C.7. Retailer: Small end customer marketing

With the variation between jurisdictions raised in the paper, and in the interests of consumers, a national Marketing Code would assist with clearing anomalies across jurisdictions. Consumers need easy access to clear information to exercise choice within a competitive market. The better informed the consumer, the more effective the market. Information asymmetry can only restrict consumers' options and hence undermine contestability. Retailers must ensure consumers are provided with accurate and comprehensible information on the products they are offering, both in written form and on their websites – it can only be to their benefit in the long run since it would promote consumer participation in the market.

The Victorian *Code of Conduct for Marketing Retail Energy in Victoria* provides an excellent model as a minimum for such a national code. While the NEM is being developed it is critical that consumer rights are protected and the ability to choose appropriately is promoted. Such a code should be made enforceable through reference in the Rules.

In particular, within the Marketing Code descriptors of "Green Power" need to be clear and accurate. Retailers and distributors should clearly identify:

- the type of generation the electricity is to be sourced from, and in what proportions;
- on what basis it is being defined as "green";
- to what degree carbon emissions are being avoided; and
- the extent to which the product is increasing the amount of renewable energy in the NEM.

Part D: Other distribution and non-price retail regulation

D.2. Business authorisation

Licensing to date has proven to be a useful vehicle for a variety of benefits. For instance, licensing can assure the soundness of a business wishing to engage, and continue, in the

electricity distribution and retail sectors. It provides that business with guidelines to assess their economic viability, which then can contribute to a reliable system.

It has also been used across the jurisdictions to promote environmental and consumer protection obligations related to government policies and regulations. To meet the initial conditions – and then maintain the licence – the companies must comply with guidelines developed in line with social and environmental policy. Licensing can then therefore act as a mechanism to ensure regulatory compliance, one that can be audited readily by business and regulator alike.

The G&T/NERA paper suggests disposing of licences altogether, and in fact deals with some of these factors in a very offhand fashion: "Existing Jurisdictional legislation (and related instruments) relating to licensing authorisation of distributors should continue but be limited to environmental matters, public and occupation health and safety matters ..." (p 68) These matters are too significant to be swept away with such little consideration.

In a sense, this is immaterial; what is material is how the attendant benefits are going to be assured in an alternative scenario. Clearly the jurisdictions vary widely in their licensing conditions, but this should not be a barrier to developing national standards. They vary widely in many other instances (such as marketing codes) where G&T/NERA have recommended instituting a national version.

If licensing is to be abolished, careful consideration must be given as to how these policies are to be embodied across the NEM.

TEC recommends that licensing for electricity distribution and retail businesses should be maintained, and that a national framework should be developed. Best practice from the NEM could be selected for the licensing conditions; they need not be at the level of the lowest common denominator. For instance, NSW has developed a set of "Greenhouse-related licence conditions for electricity retailers" which could form a useful model. The purpose of the conditions is to reduce the production of greenhouse gases via benchmarks, "through which electricity retailers were asked to reduce per capita carbon dioxide equivalent ($CO_{2\text{-}e}$) emissions."[19]

A report by the Foundation for Effective Markets and Governance for the Public Interest Advocacy Centre[20] discusses the issues concerning licensing in some detail. Their assessment is that licensing, and licence conditions, "significantly assists achievement of regulatory compliance ..." They give these reasons:

- *First, the initial licence granting allows a process of assessment of companies prior to market entry. ...* [and] *companies actually find the licensing process valuable. It is seen as more efficient to go through such a process and to get the business plan right ... than it is to find a mismatch between regulation and the business plan after entry ... The value of codes and guidelines to companies is that they obviate much work on internal compliance systems.*

[19] NSW Government, *Greenhouse-related licence conditions for electricity retailers: NSW Government Position Paper*, December 2001
[20] Foundation for Effective Markets and Governance, *Regulation and Consumer Benefit: Compliance in the National Energy Market – A Discussion Paper for the Public Interest Advocacy Centre*, November 2005, pp 68-69

- *Second, a license is an asset. When this asset is under any kind of threat the bank financing the licensee is interested. …*
- *Third, a license system can be much more responsive to changing market conditions resulting from economic, social and technological changes. Altering a license condition such as by way of revising a code with which the license requires compliance is much more readily done than getting changes to legislation. …*
- *Fourth, non-statutory ombudsman schemes are given life by license conditions. …*
- *Fifth, having licenses that provide for consumer protection gives the licensing agency a role in achieving consumer protection regulatory compliance.*

Therefore, on balance it seems prudent to develop a licensing system at the national level. Although there are few precedents in Australia of national licences, nonetheless it should be feasible to develop such a system. It could be administered through a Licensing Code which is referred to in the Rules, with the contents of the Code being based on best practice for environmental, consumer protection and prudential obligations.

D.4. Distributor interface with embedded generators

Connection of embedded generators

The national regulator should articulate clear, standardised provisions for connection by small/embedded generators into the network system, as the G&T/NERA paper proposes: "In order to remove potential barriers to entry for embedded generators, there should be a transparent and nationally consistent set of terms and conditions governing the connection of embedded generators to distribution networks." (p 71) Generalised suggestions are presented in the Rules but no firm provisions. General principles should also provide for connection into the transmission network system (although rare, there remains the possibility and the principles should be the same). The proposed terms and conditions presented in the G&T/NERA paper are reasonable in addressing many of the issues facing the distributors and generators, but are insufficient.

CRA have also presented a list of requirements for the interface with embedded generators (although this was framed in terms of a Code of Practice). They suggest that the essential elements are[21]:

- *Information disclosure protocol*
- *Protocols for DNSP dealings with embedded generation proponents: Outlines contact procedures …*
- *Negotiating Framework: Sets out framework for negotiations between DNSPs, embedded generators, and third parties.*
- *Specification protocol: Defines financial threshold at which it is considered "reasonable" for a DNSP to issue Request for Proposal for non-network solutions to constraints. …*
- *Evaluation protocol: Defines procedure for evaluating options for resolving emerging network constraints – network augmentation, Demand Management, Embedded Generation, others.*
- *Standard contracts*
- *Avoided TUOS calculation*

[21] Charles River Associates (CRA), *Codes of Practice for Embedded Generation*, February 2004, pp 18-19

- *Avoided DUOS calculation*
- *Network support payments*
- *Avoided network augmentation costs*
- *Pricing methodologies*
- *Metering requirements*
- *Licensing requirements*
- *Connection requirements.*

The existing situation is variable across the jurisdictions, and has been far from promising for the development of embedded generation. For instance, embedded generators are suffering from inadequate compensation for the benefits that they provide for avoided distribution and for reducing overall network load, particularly at peak times.

In practice, proponents of embedded generation alternatives to augmentation seem to be penalised in the sense that they may be expected to pay for more than specific connection costs. The current system allows for new generators to pay only shallow connection costs, that is, to cover the costs of assets directly required by a new connection. This applies equally to large, remote generators as to those situated closer to load points. It appears, however, that smaller, local generators may be charged for upgrades to the network, where the extra load necessitates some augmentation of the system beyond those required specifically for the new connection (deep connection costs). This contravenes the general principle of paying shallow costs established for connection into the transmission networks and, moreover, the spirit of "open access" the NEM is based on.

There is some argument for charging generators for more than just the costs associated with their connection into the system; if there were no established distribution system, there would be no conduit for the generators to sell their product. What is particularly inappropriate, however, is the differential in charging for major generators and embedded generators; the charges should be based on the same principles.

Existing large, remote generators must contribute in some fashion; those of this type would have already benefited from the shallow connection approach in the past. It is also manifestly unreasonable to force a small, local generator to pay the full extent of deep connection costs when it may only be adding a minor extra load to the network. The new Amendments to Chapter 2 of the Electricity Distribution Code in South Australia acknowledge this[22]:

> *2.7 Augmentation charges*
>
> *The distributor:*
>
> *(a) must not charge a small embedded generator for any augmentation required as a result of the connection of the small embedded generator's embedded generating units to the distribution network; and*
>
> *(b) may only charge a large embedded generator an augmentation charge for any augmentation required as a result of the connection of the large embedded generator's embedded generating units which has been calculated:*

[22] Essential Services Commission of South Australia, *Amendments to Chapter 2 of the Electricity Distribution Code: Connection of Embedded Generation Units*, June 2005

> *(i) as an excluded service charge under the Electricity Distribution Price Determination; and*
> (ii) *in accordance with the requirements of Chapter 5 of the National Electricity Code* [sic].

Upgrades are part of normal expansions of the network system, and thus networks generally recover the costs by an increase in prices (or their asset base, under a revenue cap system). However, exceptions could be made where it can be proven that any new connection will lead to a substantial constraint or expenditure (such as a large generator, or one in a remote location), that is, in these cases the network should not be permitted to recover the costs of such an augmentation. This would encourage competition and the entry of small/local generators, as well as consideration of non-network solutions.

Another type of exception could be made in reverse, where an alternative energy source/generator is being proposed (non fossil fuel, for instance). In these cases, arrangements could be made at a national level for government subsidy of the augmentation. One example could be the connection of a series of wind farms; the Wind Energy Policy Working Group pointed out that a deterrent for such generators and associated network service providers was the potentially high cost of connecting wind farms into the network[23]:

> *The nature of wind as a potential major renewable electricity generation resource means that viable wind farm sites are likely to be clustered in rural regions that have limited local electricity network service assets. As such, significant network extensions are sometimes required to link the potential wind farm site/s to the existing distribution or transmission networks which in turn may require augmentation to provide the needed grid connection transfer capacity.*

The Group noted that connections would generally be made individually rather than through an overall design, which is short-sighted since wind farms in particular are likely to be clustered in distinct localities. Difficulties with businesses forming consortia – although a logical solution – were acknowledged. This is a case where national leadership would assist, through development of an energy generation plan for a locality along with subsidisation of network augmentation where necessary.

A further benefit of embedded generators is that they can offer consumers in rural communities a more reliable alternative to the standard distribution network. Small communities often lack the financial resources to attract system expansions and often suffer more greatly from outages based on system constraints at the end of the line.

A balance needs to be struck to allow smaller generators easy access to the system, while providing for fossil fuel generators remote from the load points to contribute to the true costs of providing network services. Any solution should be prescribed in the Rules, to promote clarity and equity of access.

[23] Wind Energy Policy Working Group, *Integrating Wind Farms into the National Electricity Market – Discussion Paper*, Report to the Ministerial Council on Energy Standing Committee of Officials, March 2005, p 22

Use of system charges

Regarding avoided use of network charges (Distribution Use of System – DUOS), we would argue for requirements to be set out in the Rules. DUOS rebates are intended to recompense local generators requiring lower use of the networks – including lower TUOS charges for DNSPs – by virtue of location closer to load points. However, embedded generation (or DG) offers a range of benefits not entirely reflected in the current method of calculating avoided DUOS rebates. As stated in the G&T/NERA paper (p 73):

> *For electricity distribution businesses, the presence of embedded generators in their distribution networks can result in a reduction in the TUOS charges that the distributors are required to pay, and also the potential to avoid the cost of network augmentation, which may have been required in the absence of the generator. The presence of embedded generators may therefore result in two potential benefits, which reduce the distributors' costs (and ultimately the charges paid by customers). It is therefore appropriate that the generators are able to be paid a proportion of this benefit, in order to encourage them to locate.*

The value of any rebates should include the avoided DUOS costs and the value of deferral of new network augmentations as well as the following:

- Annual operating cost of the deferred augmentation
- Total annual net cost of servicing the capital expenditure of the deferred augmentation including:
    - financing charges
    - capital depreciation.

Including the full value of deferral of network augmentations in the calculation of rebates would provide more accurate price signals across the NEM. Such an approach would also encourage the network service providers to more fully utilise the benefits of non-network solutions, by making the true costs – and long run costs – more transparent since it also presents an opportunity for recognition of long-term effects.

If the connection into the network – or DSM or other non-network options – contributes to the cost-effectiveness or reliability of the system in some way, then there should be payment in kind from the DNSPs via rebates since it is to the financial benefit of the network businesses in the long term.

D.6. Metering

The National Electricity Market Management Company (NEMMCO) is responsible for overall metrology procedures and has recently released a revised version of these[24] (after the production of the G&T/NERA paper, completed in May 2005). The NEMMCO report is intended "to clarify the principles to be applied when developing changes to Chapter 7 of the National Electricity Rules", and their proposals are to: "define the principles, obligations and requirements that are to be applied in the full end-to-end NEM metrology framework", taking jurisdictional policy into consideration. Therefore our comments on this section of the G&T/NERA paper have been formulated in light of the proposals of the NEMMCO paper as well. We have restricted our comments to electricity metering, and we

[24] NEMMCO, *Principles for NEM Metrology Procedures*, Revised July 2005

have also assumed that although NEMMCO will be the metrology coordinator it is the AEMC and the AER who will develop policy and then be responsible for regulation.

It appears from the NEMMCO paper that the basic underlying principles of metrology procedures will be standardised nationally, which is appropriate given the moves towards a national market. Their recommendations in fact seem to go beyond that of the G&T/NERA paper, which allows for various exclusions – for instance, for types 5, 6 and 7 meters, for which the jurisdictions can continue in the role of metrology coordinator if they wish to do so. This is absurd within an allegedly national system and the NEMMCO position is our preferred one. We also support the concept of an, "extended framework [which] includes all requirements from a meter, through the management of a metering installation and its data and related information, to the associated metering services, and the business processes that interact with the metering data and information. Hence, the amended Chapter 7 and its associated procedures need to set out the principles, obligations and requirements for the complete end-to-end process, from meter to billing-ready data – a NEM metrology framework."[25]

Metrology procedures should be nationally regulated to allow consistency for all parties. Furthermore, a standardised system of interval metering should be installed across the NEM. The metering system should be based on the best available, which currently is advanced interval meters ("smart" meters). There are many benefits which can arise from the use of advanced meters. Demand management is the most obvious, with the possibility for load shifting and load reduction once end users can readily keep track of their consumption. The User Participation Working Group presented a number of other potential benefits[26]:

- *Avoided capital costs of new generation and network capacity;*
- *Avoided variable costs of energy generation;*
- *Avoided manual meter reading costs;*
- *Improved operational network management including near real-time measurement of network losses;*
- *Reduced greenhouse gas emissions from a reduction in peak demand (where there is not a shift in consumption to more emission intensive generation at another time of day);*
- *Increased settlement accuracy;*
- *Pricing flexibility and accuracy;*
- *Fraud detection;*
- *Opportunity to integrate electricity metering with gas and water;*
- *Remote connection and disconnection capability; and*
- *Premise outage detection and event record and communication.*

It is critical to install state-of-the-art technology that has the capacity for remote control technologies and communications, since retrofitting in the future would add a significant cost for consumers and create another unnecessary barrier to DM. Advanced interval meters allow for remote communication which can give the end user up-to-date information on their consumption. Smart meters also provide the capacity for targeted

[25] NEMMCO, *Principles for NEM Metrology Procedures*, Revised July 2005, p 5
[26] User Participation Working Group, *Common Principles for the Assessment of Interval Meters: Overview paper*, Report to the Ministerial Council on Energy Standing Committee of Officials, June 2005, pp 7-8

systems and appliances to be shut down when necessary (remote load control). They therefore allow for both demand management and load shifting, and thus a potential reduction in the need for augmentation of the whole system to deal with peaks. It is therefore essential that the national regulator ensures that consistent and up-to-date technology is adopted across the NEM. The Rules need to establish that metering into the future is based on the most effective technology available.

The Rules also state that metrology procedures should be "economically efficient". This gives further support to the installation of advanced interval meters, which make transparent the costs of electricity in times of peak demand, rather than relying on the existing accumulation meters and the corresponding tariffs which average (or "smear") the cost out over the billing period. The Bayard Group points out that, "Recent deployments of smart metering systems have demonstrated that by enabling innovative pricing, appliance control and real-time customer feedback the widespread financial and environmental benefits of efficiency can be harvested."[27]

Therefore, in the interests of economic efficiency, customer benefit and demand management, metering principles should address the following:

- interval meters are essential, with the provision for pricing by time of use;
- remote communication is essential, for provision of up-to-date information for both the retailer and the consumer. It also gives greater reliability of meter reading since it is automatic, and reliant on technology rather than manual reading. It also allows for recording of export of electricity where an embedded system is installed;
- in-house information display allows the customer to intervene directly in their consumption to activate load shifting and load reduction;
- in-house displays need to inform the customer of consumption, tariffs, and carbon dioxide emissions and/or savings;
- remote load control gives the opportunity for precise management of demand, with the agreement of the consumer.

The MCE has agreed in principle to the rollout of interval meters: "All NEM jurisdictions which have not done so should review the use of interval meters and assess the relative benefits of an interval meter rollout by 2007."[28] This is too long a timeframe, nor is it stringent enough, since it only requires assessment by 2007 not implementation. The benefits of interval metering, and associated tariff schemes, are so extensive that the rollout should begin by 2007, not just assessment.

D.9. Jurisdictional Directions

The G&T/NERA paper states that, in regard to distribution price regulation, "The national approach replaces the current disparate arrangements between states and as a result the overall transparency of the regime is enhanced." (p 12) This is true for many factors, but

[27] Bayard Group, accessed online at http://www.bayardcapital.com.au/whysmartmetering.htm, on 4.1.2006
[28] Ministerial Council on Energy – Standing Committee of Officials, *User Participation Policy Framework,* August 2004; cited in User Participation Working Group, *Common Principles for the Assessment of Interval Meters: Overview paper*, June 2005, p 3

not for environmental or customer service obligations, which they have in fact left with the jurisdictions (along with a variety of other details).

Environmental and social policy cannot be divorced from economic policy.

To consider these three as mutually exclusive is far too simplistic a view of a market system. Economic policy will inevitably have social and environmental consequences, and the reverse also applies. Therefore, in a national system, social and environmental outcomes must be taken into consideration at a national level, not just handed over to jurisdictional governments. If this has been done to address jurisdictional sensitivities, then it is not good governance.

We have made various references throughout this paper to areas where we do not consider a Jurisdictional Direction to be an appropriate mechanism. The whole point of the move to a National Energy Market is to develop a consistent system for generation and provision of electricity across Australia; presumably there is more at stake than simply the sale of electricity across state borders. Therefore, as much as possible should be dealt with at a national level.

There are two prime examples of mechanisms that could be lost through over-reliance on Jurisdictional Directions. One is the possibility for developing a national licensing system, which could be used to impose environmental, social and prudential conditions on businesses engaging in the NEM (see section D.2 on business authorisation). The other is that of Codes of Practice (for a variety of subject areas), which would also mostly be lost within an environment of handing over responsibility to Jurisdictional Directions. The Codes suggested within the G&T/NERA paper on the whole relate to commercial factors (such as a marketing code), but Codes can also be useful for promoting a range of government policies, particularly if they are given standing within the Rules.

The concept of a Jurisdictional Direction as devised by G&T/NERA is an interesting and innovative one, and we would not dismiss it out of hand. Clearly the market – as well as environmental, social and economic contexts – will continue to change and such a mechanism would allow for change over time. It would also allow for individual jurisdictions to develop binding conditions in a formal arrangement for new features they may wish to impose on all companies involved in the NEM, since they need not be limited to distributors and retailers but could equally be used for generators and TNSPs.

However, the concept should be applied with caution and responsibilities transferred to the national level wherever possible.