TOTAL ENVIRONMENT CENTRE ALTERNATIVE TECHNOLOGY ASSOCIATION ETHNIC COMMUNITIES' COUNCIL OF NSW

SUBMISSION

Ministerial Council on Energy
Network Incentives for Demand Side Response and Distributed Generation

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Network Incentives for Demand Side Response and Distributed Generation

1. Introduction

1.1 DSR, DG and the NEM

Total Environment Centre (TEC), the Alternative Technology Association (ATA) and the Ethnic Communities' Council of NSW (ECC) are pleased that the Ministerial Council on Energy (MCE) has directed NERA Economic Consulting to undertake an investigation of network incentives for demand side response and distributed generation. The Standing Committee of Officials (SCO) of the MCE noted that[1],

> *MCE's EMRWG* [Energy Market Reform Working Group] *is seeking to integrate consideration of Demand Side Response (DSR) and Distributed Generation (DG) into the development of the national framework for distribution. In particular, EMRWG is interested in the impact of the proposed initial Rules regarding any structural or regulatory impediments that may impede DNSP's incentives to support the development or uptake of economically efficient DSR and DG.*

We note that "demand side response" (DSR) generally corresponds to the term "demand management" (DM) as we have been using it in previous submissions to the MCE[2]. We have primarily responded in this submission to the paper by NERA, *Part One: Distribution Rules Review – Network Incentives for Demand Side Response and Distributed Generation* (referred to here as "the NERA paper").

TEC and ATA previously contributed to submissions – including in conjunction with other members of the Climate Action Network of Australia (CANA) – in response to the PB Associates Consultation Paper of February 2006 on a Draft National Code of Practice for Embedded Generation. Many of the issues canvassed in those submissions are relevant here, and we attach the CANA submission of March 2006.

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. DSR and DG must therefore be given high priority and be integrated in uniform national regulation, that is, non-network solutions must be promoted as a first choice for energy service provision rather than augmentation where perceived constraints need to be alleviated.

The most important solutions for establishing a robust demand-side presence in the electricity market include:

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[1] Standing Committee of Officials of the Ministerial Council on Energy (2007) *NERA Economic Consulting – Review of network incentives for Distributed Generation and Demand Side Response*, p 1

[2] We have used DM to include various terms, such as '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.

- establish a DSR funding mechanism
- establish a DSR code of practice and finalise the proposed DG code of practice
- ensure networks investigate and implement non-network solutions (such as DSR and DG) as an alternative to network augmentation
- establish economic incentives throughout the NEM for the implementation of DSR and the use of small, local generators based on alternative energies; in particular there must be suitable mechanisms for recovery of costs for efficient non-network investment
- introduce mandated feed-in tariffs for all small-scale DG to stimulate investment in the DG sector
- ensure networks disclose information on impending constraints and opportunities for DSR and DG in a timely manner
- provide transparency of pricing in relation to demand and constraints – end users are currently unaware of the true price of their electricity, including network charges. Advanced meters and time-of-use tariffs – which we support – will assist this goal, but are not sufficient in themselves. (Note that in this submission we are using the term 'time-of-use tariff' to refer a range of tariffs based on the time of consumption, for instance critical peak pricing and real-time pricing.)
- develop a market mechanism for short-term and long-term DSR to facilitate DSR aggregation services.

In general, the discussion in the NERA paper of the barriers facing DSR and DG is wide-ranging and informative, and due recognition is given to most of the efficiency and reliability benefits they can bring. The recommendations dealing with removing specific barriers to embedded/distributed generation are generally quite useful, but the other recommendations are fairly weak. The problems are clear but the solutions offered fall short of achieving genuine removal of barriers and promotion of incentives. The SCO presented the view that, "EMRWG would like stakeholders to consider and comment on whether the proposed changes as a package effectively improve the balance of incentives for network owners to compare network alternatives to network expansions."[3] The answer is yes, but only minimally.

It is as if NERA has gone so far in the attempt to *not* advantage DSR and DG that they have instead failed in substance to change the status quo, thus leaving many impediments in place (since these options are currently disadvantaged). NERA has fallen short in providing ideas for genuine incentives to encourage the uptake of DSR and DG – the system has overlooked the benefits of these mechanisms for so long that it is time to develop imaginative solutions to promote them. These could be introduced via transition periods with active promotion of non-network solutions to give networks experience in the benefits of incorporating non-network solutions as an antidote to the massive inertia so far. We understand NERA has limited the discussion to, "implication of the initial rules on DNSPs' and customers' incentives to undertake DSR and DG" (NERA paper, p 1), but by doing this they have neglected to address the overwhelming magnitude of the bias against alternative solutions. Thus the report, in the end, is very disappointing.

[3] SCO of the MCE (2007) op cit., p 4

1.2 Need for environmental and social objectives

There are clear efficiency benefits to be gained from the implementation of DSR and DG mechanisms, but they also can provide environmental and social benefits in the long-term interests of consumers. It is not efficient to concentrate solely on monetary prices and costs, which ignore the external costs to consumers from the generation of electricity from fossil fuels. A focus on supply-side – and, in this context, network-driven – solutions is archaic in light of the exposure of the impacts of climate change. For instance, governments are now realising that energy efficiency is the cheapest, largest and quickest option for reducing greenhouse gas emissions, and closing out DSR solutions creates a major unnecessary financial risk for network businesses if government policy leads to significant reduction of consumption.

TEC, with other non-government organisations, strongly urges the insertion of environmental, social and DSR objectives in the National Electricity Law to complement the overarching market objective.[4] If these were in place, regulators would be more inclined to investigate DSR and DG regulatory options as a first step, and incentives to bring balance into the demand-supply equation would be a focus. Without making environmental, social and demand management objectives core to the NEM, DSR and DG investigations will always remain marginal and be forced to swim against the stream of an excessively supply-focused regulatory system.

1.3 Network incentives

Since networks are not required under current regulations to implement non-network solutions even when they may be cost effective, there is a strong tendency to focus purely on new infrastructure as an answer to increasing demand. Incentive mechanisms for the pass-through of DSR costs are needed to counter the inappropriate focus on the supply-side of energy service provision and to limit inefficient over-investment in network infrastructure. The absence of incentive mechanisms for the implementation of demand management and other non-network solutions is resulting in inefficient, peak-demand driven distribution infrastructure investments.

The bias in regulatory incentives for network businesses is highlighted in the approach to cost recovery. Typically, networks are permitted to recover a return on the full value of a network investment as soon as any part of that investment is deemed to be necessary. By contrast, the full value of an investment in DG and/or DSR is only considered to be eligible for cost recovery where the business demonstrates that the full value of this investment has been effective in deferring a specific network investment. Progress will only be made in promoting DG and DSR when networks can recover only the cost of that part of a network that is actually used; and when they invest instead in extra DG and DSR capacity to allow for plausible contingencies.

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

The 'D-factor'[5] incentive mechanism initiated by the Independent Pricing and Regulatory Tribunal (IPART) in NSW for distribution network service providers (DNSPs) has helped to spur networks into investigating and carrying out DM solutions. It enables networks to pass through the costs of DM projects, ensuring an appropriate rate of return on this investment. The response to the D-factor incentive mechanism in NSW to date (while modest) is promising, indicating that this approach is a valid means of promoting more efficient network investment under a price cap form of regulation. South Australia has also developed an incentive mechanism. However, NERA fall shorts of recommending either of these possibilities and does not offer any alternative, solid incentive method that could be incorporated within the Rules. This is a significant deficiency in the report.

The transparent and thorough investigation of DSR and DG alternatives to network augmentation should be made clear through the Rules to ensure that these investigations are central to the determination of proposed efficient capital expenditure by the Australian Energy Regulator (AER). It can be difficult within the current regulatory climate to argue the prudency of DM expenditure and there needs to be a clear mechanism for cost recovery for the investment. In addition, a shortfall in predicted DSR savings may leave a DNSP at risk of carrying the full capital cost of an alternative (supply-side) means for meeting its reliability requirements, therefore the eligibility of DSR-related capital expenditure should be made explicit. In the event that expected DSR resources do not materialise as planned, the eligibility of capital expenditure undertaken to implement supply-side solutions where needed should also be made explicit.

We recommend also that, since DNSPs are not yet fully experienced in DSR measures, the MCE pursue a transitional mechanism. The aims would be to reduce risk – such as by allowing DNSPs to become familiar with DSR techniques for meeting time and load targets – and to develop strategies for maintaining service and reliability requirements wherever DSR does not meet the required targets. A complete investigation of the potential of DSR could include milestones for DNSPs to develop DSR implementation plans as well as exit strategies to allow alternative measures to be undertaken. Such a transitional mechanism could include procedures for the DNSP to interact with the AER in finding solutions for such situations on a case-by-case basis. In addition, it is essential that there should be a requirement for explicit demonstration that non-network solutions have been considered.

Another transitional measure would be to draw on the experience of both NSW and South Australia by establishing a D-factor mechanism, thus guaranteeing a given initial level of cost recovery for DSR. As an extra measure, the AER– like the Essential Services Commission of SA (ESCOSA) – could stipulate a minimum annual level of network expenditure in DG and DSR for a number of years of at least 5% of proposed annual capital expenditure. Recovery of this expenditure should be allowed in the same year that it was incurred as long as the network used it for genuine efforts on DG and DSR implementation, even if the outcomes did not meet expectations. On the other hand, if this expenditure is not spent on DG and DSR then it would need to be returned to consumers in subsequent years on a 'use it or lose it' basis. The networks would need to

[5] Independent Pricing and Regulatory Tribunal of New South Wales, *Guidelines on the Application of the D-factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination*, April 2005

account for this expenditure ex post, as is currently the case for the NSW D-factor. Where the expenditure is approved by the AER as effective and prudent, the cost recovery mechanism would roll forward to future years. If the AER determines that the expenditure is ineffective or imprudent, then this transitional mechanism would expire.

Development of a price mechanism for DSR aggregation arrangements would facilitate uptake of DSR in the NEM. It would not only make investment more attractive but would also enhance the reliability benefits of DSR and reduce the perception of lack of firmness NERA refers to. The absence of either a firm short- or long-term price for DSR is a critical flaw in the market. The lack of longer-term prices inhibits the potential for capital investment to optimise the amount of DSR, as well as to increase transaction costs for retailers and DM aggregators. It appears that the MCE is investigating the means for establishing a short-term price process, but this investigation should be brought forward.

The proper implementation of tailored price mechanisms in response to advanced metering would also assist here. The MCE has given the go-ahead for the use of 'smart' meters across the NEM, but progress on developing tariff structures is lacking. Advanced metering infrastructure (AMI) incoroporating varied tariff plans, including dynamic time-of-use pricing by both distribution and transmission networks, will increase the importance of DSR within the NEM (as NERA points out) as customers implement their greater range of choice, with the potential for reduction not only of peak loads but also of base loads. This can only improve the reliability contribution of DSR.

1.4 Scope of this submission

We have addressed only those findings and recommendations with which we take particular issue or with which we strongly agree, that is, we have not addressed every recommendation presented in the NERA paper. Additional recommendations have also been proposed where lacking. This submission is organised by chapter number from the NERA paper.

2 Response to recommendations

Chapter 4 – Form of regulation: General discussion

Throughout the NERA paper there is an underlying assumption that competition exists between DNSPs. This is a complete fantasy. Like transmission networks, although obviously on a smaller scale, distribution services rely on significant capital investments and hence form natural monopolies by geographic region. For example, in some jurisdictions there is only one DNSP for the whole state (such as Tasmania and South Australia), Queensland only has two, and even NSW – the most populous state – only has three DNSPs operating as regional monopolies . Because of the type of infrastructure, it would be impractical and inefficient to duplicate these services as well as being highly capital intensive. Thus the services are not truly contestable.

TEC takes issue with the failure of regulators to acknowledge DNSPs as natural monopolies in contrast with the treatment of TNSPs, which are understood to be such monopolies. DNSPs do form monopolies, by a number of criteria:

- Although capital investment in distribution networks is not as lumpy as for transmission, nonetheless there are high capital costs (poles, wires, transformers, sub-stations).
- There are physical reasons for geographic monopolies, that is, it would be counter-productive and inefficient to duplicate the physical infrastructure: there are economies of scale which cannot be replicated.
- DG does not counter this market power, since the electricity generated is injected into the existing infrastructure via a distribution network.
- Customers (effectively retailers or embedded generators) have limited power over the service provider and access costs are largely hidden, except perhaps for large consumers.
- For electricity the alternatives are generally limited and virtually all households in Australia have electricity. In many areas there is no gas provision; there are some alternatives for heating (space and water) but substitution is limited for many uses (lighting, appliances).

We strongly believe that DNSPs should be treated as local monopolies, as for transmission network businesses, which means the direct control form of regulation is the most logical form to be used. Negotiate/arbitrate or no regulation forms leave too much room for the DNSPs to use their monopoly power; this is not appropriate in an industry which provides an essential service.

4.3 Negotiate Arbitrate Form of Regulation

The report correctly identifies the range and degree of information asymmetries which presently exist between proponents of DG and DNSPs, and the resultant impediments for DG projects. We would welcome the open and transparent provision of information surrounding technical, financial and regulatory situations and requirements by DNSPs, including open and clear information on areas of network constraints, in order to assist in planning for DG implementation (see also section 8.3, below). The NSW *Demand Management Code of Practice for Electricity Distributors* and the South Australian *Industry Guideline 12: Demand Management for Electricity Distribution Networks* provide models for the minimum level of disclosure and as a the basis for evaluating network support payments.

4.3.2 Service scale and the efficiency of negotiations

Many of the issues presented in this section have previously been addressed in the *Draft Code of Practice for Embedded Generators*, which was developed by the MCE Renewable and Distributed Generation Working Group (RDGWG). As we noted above, ATA and TEC, along with other CANA members, contributed to submissions on the draft code and we have attached the joint CANA submission.

This submission called for the development of standard connection agreements for small distributed generation, along with other measures to address the impediments faced by small-scale renewable and distributed generation projects. We support the development of standard terms and conditions for the connection of small DG, as well as the suggestion that a requirement for DNSPs to develop standard agreements should be incorporated into the initial Rules.

Further, we believe that the development and implementation of the Code of Practice for Embedded Generators would go some way to addressing the concerns around impracticalities of negotiating grid connection terms and conditions for all small-scale DG, as well as overcoming a number of additional barriers faced by proponents of these technologies. We would encourage the completion of the RDGWG process and the timely implementation of a code of practice addressing the many and varied additional impediments.

Recommendation
The Rules should require that, once the appropriate form of regulation is determined for domestic distribution use of system charges, DNSPs should be required to allow such customers to install and use PV on the basis of the same usage and capacity tariff elements applying to equivalent sized load.

For small-scale DG projects the cost of applying the negotiate and arbitrate form of regulation would far outweigh any potential benefits arising out of the value of service. As such, it is clearly preferential for the Rules to require that small-scale projects (that is, less than 100kW) be regulated by direct control rather than negotiate-arbitrate regulation.

Further, it is important that any Rule changes refer to *all* small-scale, low-emission DG, rather than being limited to solar PV. Internationally there has been a rapid growth in small-scale wind energy installations embedded in distribution networks. Additionally, potential exists for micro-scale hydroelectricity to be grid-connected in certain locations as well as the implementation of domestic fuel-cell cogeneration technologies, as seen recently in Japan. As such, these technologies should not be precluded from the recommendations of this review.

Chapter 5 – Determination of a revenue requirement

5.2 Building Blocks Specification

Recommendation
Provision in the Rules for the inclusion of payments made by DNSPs for ‘network support’ expenditure in the derivation of the building block revenue requirement should be retained. The method for recognising network support payments in the derivation of the building block revenue requirement should provide unbiased incentives for the efficient substitution of network support for network augmentation.

Network support payments are an important incentive for DSR and DG investment and it is fair and reasonable that support for contributions to reliability or other service standards be acknowledged and paid for. We therefore support the recommendation but regret potential incentives were not proposed in the NERA paper. The case study described in Part 2 of the DSR and DG papers on the DSR aggregator was useful on this subject, but we reiterate that the lack of short-term and long-term prices for DSR is a significant barrier to network support.

5.2.1.1 Efficiency benefit sharing mechanisms

Recommendation
The range of regulatory measures available to address the potential imbalance of incentives as between capital and operating cost expenditure should include:
- allowing (but not requiring) the AER to include a capital expenditure efficiency incentive mechanism in the building blocks control setting method for individual DNSPs; and
- requiring the AER to consult on the potential DSR and DG incentive implications of any proposed operating or capital expenditure efficiency incentive mechanism.

The tendency for DNSPs to prefer capital expenditure over DSR, DG or other non-network solutions which rely more on operational expenditure is referred to in many parts of the NERA paper. We would agree with this assessment, and support the recommendation regarding the AER. It is not clear, however, why the AER should not be required – but only allowed – "to include a capital expenditure efficiency incentive mechanism". This should be strengthened. The recommendation also requires clarity regarding who the AER would consult with – we would support an open, public consultation process to develop an incentive mechanism. It is also not clarified who the AER should consult with, and we would propose an open, public consultation process.

5.2.2 Predilection for investment in own network assets

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

We support this in principle, but consider it should go further. As NERA points out, the default position is for DNSPs to employ network solutions and so there needs to be an alternative incentive or requirement provided for them to accurately assess and then implement non-network alternatives as a primary option. It is not enough for them to only consider alternatives; they need to proactively pursue them and then put them into practice. Where this has not been done effectively, the AER should disallow the recovery of costs for augmentation solutions. Anything short of a stringent approach to the assessment of DM/DG take-up is implicit acceptance of the status quo where supply-side options are favoured. We would regard this recommendation as a first step only, and note that the NSW Demand Management Code of Practice would be a useful model for resolving at least part of the problem.

5.2.5 Demand management incentive arrangements

We would consider this to be the crux of the DSR issue. Although NERA examines one option (the NSW D-factor) there is no canvassing of other possibilities nor recommended action. The conclusion seems to be based on a naïve and unsubstantiated faith that instituting a price cap and time-of-use tariffs will take care of the problem. This is highly sub-optimal and we have addressed a number of these issues in other parts of this submission. The same comment applies to 5.2.3 and 5.2.4 as well; it would have been more productive if NERA had developed recommendations to address the barriers.

It is a matter of great concern that in writing a report on network incentives for DSR and DG, NERA appears to have failed to appreciate one of the most fundamental aspects of the incentives created by price regulation. In a context of high fixed and low variable costs, applying price cap regulation that links total revenue directly to sales volume will inevitably create disincentives to mechanisms that reduce those sales. This is true whether the sales volumes are measured in simple 'anytime' kWh with accumulation meters or with variable time-of-use tariffs. Where the marginal revenue (that is, price under a price cap) is higher than the marginal cost, networks will be discouraged from undertaking any DSR or DG that reduces sales. This is why electricity regulators in other countries have created mechanisms to decouple electricity sales volume from network revenue (and profits).

Obviously time-of-use tariffs are also important as they will be crucial in providing incentives to customers to shift load at peak times with the potential of reducing overall demand. Such tariffs, however, will not encourage networks to invest in DSR or DG measures that reduce overall energy consumption. This is one of the reasons IPART developed the D-factor mechanism, even if it has only provided a partial response.

5.3 Alternative Control Setting Methods such as TFP

In the NERA paper Total Factor Productivity (TFP) is discussed as a potential alternative to the building block methodology, which is in general use across the NEM. The building block version is a relatively clear and understandable methodology, which means it is accessible to interest groups, industry and the regulator, and it can help make decision-making processes relatively transparent. In contrast, the TFP methodology is problematic to use as different factors may not remain constant and it can be difficult to weigh their individual contribution. Industry-wide costs would need to be established, alongside demand and efficiency trends, on a regular basis. In a relatively young market like the NEM, this can entail costs in setting up the system and deriving baseline data; costs to industry which may need to change reporting systems; and costs in keeping the information up to date.

It is possible that a TFP methodology may optimise benefits for both network businesses and consumers, however the extent of these is currently uncertain. It is more efficient to have a clear, consistent methodology prevailing across the whole system, and currently there is insufficient reason to opt for TFP as the preferred methodology (even when DNSPs 'have been subject to independent regulation'). At this stage the ramifications within the NEM are unknown without a great deal more research, and this needs to be undertaken as a matter of urgency since TFP is frequently being raised as an option in discussion about reform of the NEM.

5.4.1 Network planning requirements

> **Recommendation**
> It is important that jurisdictional standard setters be cognisant of the DSR and DG incentive implications of network planning or service reliability standards. Consideration should be given to the use of probabilistic planning standards and their relative costs and benefits as compared with deterministic standards.

Prescriptive and deterministic standards have certainly been used to argue against non-network solutions because of perception that they lack firmness. It is less clear, however, that prescriptive probabilistic standards would lead to a significant increase in the network support for DSR and DM. While we support this recommendation, it should not be regarded as a key priority in removing barriers to DSR and DG.

5.4.2 Regulatory Test

There is no recommendation given here about the Regulatory Test, although NERA presents a range of its shortcomings. This creates an internal problem with the Paper as it is contradictory to other parts of the document (such as in 9.2.2 about DG), where the use of the Test is presented as contributing to support of non-network solutions.

The new Clause 5.6.5A of the Rules referring to the Regulatory Test (operating since 30.11.2006) does include requirements for businesses to consider non-network alternatives and to include proper assessment of the derivation of costs and benefits. However, a number of difficulties remain with the actual Test, including the fact that it is rarely applied to DNSPs. NERA also points out that the Energy Reform Implementation Group considered it to be in need of an overhaul. We recommend that the Regulatory Test be thoroughly reviewed via public consultation and non-network techniques promoted as a first-step solution; this is another case where environmental, social and demand management objectives in the NEL would assist with the proper assessment of non-network solutions. In addition, the fact that the AER is responsible for development of the Test itself means that it is less binding and more open to interpretation.

Chapter 6 – Service regulation and incentive

6.1.3 Incidence of penalties and rewards

> **Recommendation**
> Where the perceived ‘firmness’ of DSR and DG present a potential barrier to their efficient uptake by DNSPs, the Rules should not prevent DNSPs from entering into service contracts with DSR and DG service providers that transfer the relevant service incentive scheme payments and penalties to such providers.

We support the recommendation in principle, but it is quite vague and contains the preconception that DSR and DG can be unreliable. The uncertainty around their value mainly results from the method of operation of the NEM, where the electricity price is set in the spot market. We understand that NERA is not stating that they are unreliable; nonetheless this recommendation is so general that it is probably unworkable.

In addition, networks themselves only achieve their required level of 'firmness' through over-built systems. It is unrealistic to expect individual DSR and DG elements to provide the same level of firmness as an integrated system of network elements and, as NERA notes, the supposed lack of firmness is based on a perception and not real data. To further enhance their reliability, DSR and DG elements can be aggregated and integrated both with each other and with the network in order to achieve optimal firmness and efficiency. Any transfer of risks, incentives and penalties needs to be undertaken equitably and not used as yet another pretext to block DSR and DG. In particular, the use of penalties against consumers providing DSR and DG should be avoided.

6.3 Service conclusions

> **Recommendation**
> The potential DSR and DG incentive impacts of service incentive schemes should be considered by the AER when specifying the operational detail, service targets and applicable penalties and rewards for such schemes. This may be achieved by including this as a principle under the initial distribution rule (equivalent to clause 6A.7.4 of the transmission rule).

The guidelines set out in the NERA paper for the AER that accompany this recommendation would make it effective, but it is essential that these are indeed followed or this recommendation too will be unworkable. These guidelines need to be accommodated within the Rules in some fashion, and they should also be strengthened with more detail on specific incentives. Development of these schemes should be based on a public consultation process.

It is worth noting again that network businesses in Australia have very limited experience in supporting DSR and DG. Imposing new risk elements on DNSPs for them to manage may simply drive them to rely more heavily on network technologies with which they have greatest familiarity, to the exclusion of DSR and DG.

Chapter 7 – Network pricing

7.6 Form of Price Control Conclusions

> **Recommendation**
> Price caps should be preferred over revenue controls for the purpose of facilitating the utilisation of DSR and DG, particularly once advanced meters and the easing of side constraints improve the opportunity for more efficient forms of pricing.

We strongly disagree with this recommendation. TEC has previously – and frequently – argued against a price cap form of regulation for DNSPs and supported the imposition of a revenue cap for DNSPs, for similar reasons as there is a revenue cap for TNSPs (that is, the monopoly nature of the business; and see the discussion above about Chapter 4 and section 5.2.5). In addition, there is more room for a DNSP to manoeuvre within a revenue cap, which means they are more likely to view DSR and DG options as viable. The revenue cap method of assessment is an important means of encouraging networks to carry out their investments prudently. Without such a cap, networks have a reduced incentive to carry out their operations within budget, and the incentive to encourage greater, and more wasteful, consumption of electricity. In addition, there is no reasonable argument for using different methodologies within a coherent framework (the hybrid form).

Although the NERA paper presents extensive coverage of disadvantages and advantages of price caps and revenue caps for the uptake of DSR and DG, there is in the end insufficient evidence given in order to support either as a preferred model. There are so many disadvantages for consumers, the networks and DSR/DG investors in a price cap form of regulation that such a sweeping recommendation should not have been made in this context.

Moreover, there are a number of concepts grouped together in this recommendation which are covered separately – and more appropriately – elsewhere (such as AMI and side constraints). We cannot support such a flawed, incoherent and unsubstantiated recommendation.

Recommendation
That the Rules should permit the AER to establish an incentive mechanism that compensates DNSPs operating under the price cap form of control for the revenue lost as a consequence of undertaking efficient DSR initiatives.

We agree with this recommendation, but there needs to be more detailed recommendations for incentives. It is encouraging that the reports notes, “However, in light of the disincentives for the DNSPs to promote DSR … under the price cap form of control, we see merit in arrangement s that allow a DNSP to recover the within-period revenue foregone as a consequence of implementing DSR projects. Such an arrangement could operate along the lines of the relevant component of the NSW D-factor scheme …”. (p 49)

If a price cap methodology is applied to DNSPs – as has been raised in many issues papers during the energy market reform process – then it must include incentives for DSR and DG to counter the massive incentives and cultural bias for DNSPs to sell more electricity. Such incentives should ensure that networks are able to recoup revenue for both the efficient cost of carrying out a non-network solution as well as for the forgone revenue from sales that would have been raised had the DSR and/or DG not gone ahead. The purpose is to promote consideration of more efficient non-network solutions and, conversely, to reduce the incentive for the networks to encourage excessive consumption (that is, by selling more electricity).

An alternative method to promote DM is for DNSPs to be required to earmark a specific minimum spending level for DM: at least 5% of the projected network capital expenditure could be set aside for cost-effective DM projects, on ‘use it or lose it’ terms.

Since the requirement for either of these would be to implement DM where cost effective, such incentives in fact promote efficiency within the NEM. 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. When, and only when, an efficient level of investment in DSR and DG has been attained should the continued provision of such support mechanisms be reviewed.

7.8.2.1 AMI and tariff reassignment

Recommendation
DNSPs should be required to reassign customers to a time of use tariff following installation of advanced metering infrastructure at a customer's connection point.

Advanced metering has the potential to offer many efficiency and non-network benefits, and NERA gives a reasonable coverage of these and potential barriers in the two parts of the paper. Such metering on its own, however, will not necessarily lead to the full realisation of these benefits without appropriate tariffs. We therefore support the recommendation but with reservations: automatic reassignment seems to be contrary to the general spirit of the regulations where consumers' interests are intended to be protected. If NERA is referring to retailers here as being DNSPs' real customers, then this is still too extreme since there will be a range of tariffs – the compulsion should be on the DNSPs to negotiate new arrangements with retailers and large users based on time-of-use, rather than automatic reassignment. There is also no guarantee that AMI will be rolled out everywhere, because coverage will depend on the results of the MCE-directed cost benefit analysis (currently in preparation).

There needs to be accompanying directions given to retailers to develop similar tariff structures, otherwise the costs will once again be obscured by the tariff structure offered to customers (since it is the retailers who generally deal with customers directly). The default offer should be a time-of-use tariff of some kind, and each existing customer should be approached as to which time-of-use tariff would be preferred since it is clear that a variety of tariffs will be developed (such as critical peak pricing).

In addition, it is essential that forms of assistance for low-income and disadvantaged consumers are developed in tandem.

Recommendation
Reassignment should be accompanied by a requirement for customer education regarding ways in which they can manage their demand to affect their bill. Further work is required to identify whether this is a role best served by retailers or DNSPs.

Education will be an important part of maximising demand reduction and load shifting. We would suggest that both parties – retailers and DNSPs – should be involved in this, since most small consumers would currently not be aware of the details of network charges, only the accumulated energy usage charges. DNSPs could piggyback on mailouts to customers by retailers. Therefore we broadly support this recommendation.

A mechanism for recovery of costs for retrofitting consumers with accumulation meters also needs to be developed, and a decision needs to be made about who (distributors or retailers, for instance) will be responsible for undertaking this.

7.9.2 Incidence effects of capacity-based charging

Recommendation
DNSPs should be required to submit to the AER for approval and publish protocols for the assessment and review of capacity demand and determination of capacity charges including:
the period over which capacity demand will be reassessed before capacity charges are reset (say, every 12 months).

This recommendation seems quite sensible, and helpful for the uptake of DSR and DG. Capacity charges must be carefully designed to reflect customers' real contribution to peak demand so as to avoid removing incentives to reducing consumption at all times, and to ensure that customers are fully aware of the cost of peak demand and when peak demand occurs. The AER will need to develop guidelines for these protocols via a public consultation process, alongside protocols for network investigation of alternative solutions.

Chapter 8 – Competitive neutrality in generation

Price cap regulation creates a short-term bias for DNSPs to maximise throughput and sales volume. If there is a lack of adequate consideration of DG (and DSR) at prudency reviews and at the roll-in of capital expenditure, then a long-term bias is created in favour of network capacity investment. As long as these fundamental biases are not redressed, competitive neutrality will not be achieved in relation to all of the following issues in Chapter 8.

8.2.1.1 Shallow and deep connection costs

Recommendation
The initial Rules should not permit DNSPs to levy on DGs either positive DUOS charges for energy exported to the grid or deep connection costs.
Voluntary payments from DGs to DNSPs should be permitted where a DG agrees to pay for upstream augmentations in order to increase energy transfer capability, in the same way that a transmission connected generator can pay for upstream augmentations of the transmission system.

We support the recommendation to prohibit DNSPs from charging DG proponents either upstream, deep connection costs or positive DUOS charges, with the allowance for voluntary payments where upstream augmentation will increase the energy transfer capabilities of the DG installation. However, in order to ensure neutrality in the application of any network supply constraint applied by DNSPs, we would recommend that any network constraint algorithms used by DNSPs be submitted for approval by the AER. These algorithms should be open and transparent, and subject to challenge by the DG proponent though a predetermined dispute resolution process.

8.2.2.1 Avoided upstream network costs

There are a number of inaccuracies presented in the discussion in this section. Specifically, the notion that a reduction in demand-based prices for small-scale DG, such as residential PV, would act as a form of network support payment is completely inaccurate. This would only be the case for the relatively few numbers of households where peak consumption aligns with times of peak production from the PV system.

A small number of homeowners (those who are at home during the day, and those with daytime air-conditioning loads) may benefit from the implementation of capacity charges. For the majority of homeowners, for whom peak consumption does not correspond with times of peak PV generation, the implementation of such a regime would result in the absence of a means of capturing network benefits from their investment, and as such they would be put at a severe disadvantage. In addition, the level of negotiation required would provide an additional and unnecessary impediment to the adoption of this form of DG.

Whilst it is true that peak demand for a constrained network may correspond closely with peak production from PV systems, it is typically commercial and industrial loads which are responsible for this demand. Generally, peak demand for residential customers is either in the morning or evenings when the largest number of residents is at home. As such, the introduction of demand-based prices for residential systems would offer little or no financial benefit for the PV-system owner, whilst their investment would be having clear benefits for the constrained network within which they are located.

We oppose the introduction of demand-based prices for small-scale DG as a proxy for the value of deferred network augmentation. Instead, we call for the introduction of mandated feed-in tariffs for all small-scale DG as a means of recognising the range of benefits that these technologies provide, one of which is the avoided network augmentation costs.

Recommendation
DNSPs should be encouraged or required to ensure that customers subject to large scale PV roll-out receive priority in the roll-out of AMI, thereby facilitating the development of network tariff structures that provide efficient signals for the installation of PV.

Network tariff structures alone, via the implementation of AMI for small residential DG systems, are insufficient to provide efficient and adequate signals for solar PV or other small-scale renewable DG. Whilst it is acknowledged that time-of-use pricing, and payments to DG, arising from the AMI rollout may assist in providing an increased price for the electricity generated from PV systems, this is predominantly a reflection of a decrease in the capacity charge for the use of networks, with the peaks in wholesale electricity prices smoothed across all tariffs by retailers. Given the potentially astronomical wholesale electricity prices at times of peak demand – corresponding with peak production from solar PV – merely rewarding investment in solar PV with time-of-use payments is insufficient and avoids a host of other benefits from the adoption of these systems. Moreover, as noted above, under a price cap form of control and in the absence of effective long-term incentives for DSR and DG, there is no guarantee that the rollout of AMI will encourage efficient network tariff signals.

We believe that the implementation of mandated feed-in tariffs for electricity from DG projects is the most efficient, just and effective way of capturing the network benefits from DG investment. Feed-in tariffs calculated on the range of benefits from each particular DG technology – from network and wholesale price benefits to environmental benefits from avoided greenhouse gas and other pollutant emissions, and including the range of industry development and job-creation benefits – are the most effective way of stimulating growth in the DG sector and avoiding upstream network augmentation costs.

Feed-in tariffs have proven successful in a range of international contexts, and without this form of incentive, the 'large-scale PV roll-out' indicated in the above recommendation is highly unlikely to occur.

It is also essential that customers with small DG who change to over to an AMI system are not disadvantaged by being subject to meter replacement charges that are not intended to be incurred by consumers later in the rollout.

8.2.2.2 Energy exported

This section of the NERA report inaccurately describes the electricity export and metering arrangements for residential PV systems nationwide as one of basic net metering, whereby PV system owners are only paid a buy-back rate in instances where total electricity generated from the PV system exceeds total electricity imported from the grid in any billing period. In practice, however, no recognised standard exists for billing and metering arrangements even within most states, let alone nationally.

For example, in South Australia, the installation of PV system necessitates the installation of a net export metering regime via an advanced meter. These meters measure both export and import of electricity, with net export or import calculated for each interval period, typically half an hour. Both the total export and import are then calculated and shown at the end of the billing period. As such, homes with PV systems frequently export electricity during times of peak production whilst importing at other times, with homeowners rewarded and charged accordingly.

Further, in some jurisdictions, certain DNSPs require PV proponents to have two meters installed separately, with gross production from the PV subsystem measured separately from gross import, and calculated accordingly. (This can also be achieved by a dual-element advanced meter.) Various arrangements exist for DNSPs and retailers in other states, with retailer tariffs for the buy-back of electricity differing widely within and across jurisdictions. For example, in Victoria buy-back rates range from around 4 cents to more than 12 cents per kilowatt hour, depending on the retailer. Indeed, some retailers even offer nothing.

Conditions for effective competition are highly unlikely to result in the provision of buy-back rates adequate to reward small-scale DG owners for their investment. In Victoria, with the longest history of retail competition, even the best buy-back rates are below the mandated standing offer retail rate, with no reward for time of production or network benefits.

We would strongly support the implementation of mandated, regulated retail tariffs for the buy-back of electricity from all small DG systems via the implementation of feed-in tariffs which capture the range of benefits and reward investment in these systems accordingly.

8.2.2.3 Avoided network losses

> **Recommendation**
> Further analysis be undertaken on whether the current treatment of losses is consistent with promoting efficient distributed generation projects.

While we welcome further analysis on the treatment of losses, and the exposing of distributors to the financial consequences of losses in order to stimulate incentives for DG projects, this recommendation is likely to delay action even further. At present there is no way for DG proponents to capture the value of avoided losses from their systems. Due to the acknowledged complexity of calculating losses for transmission and distribution networks, we would encourage the implementation of mandated feed-in tariffs for DG projects act as a proxy to capture these avoided losses, along with the range of other benefits, as outlined above.

8.3 Pricing of Negotiated DG Connection Charges

We welcome the acknowledgement in the report of the need for the provision of open and transparent information by DNSPs, and fair and robust negotiation procedures for medium and larger-scale DG projects. As mentioned in our response to 4.3.2 above, we call for the introduction of standard connection charges and agreements for all small-scale DG projects less than 100 kilowatts, as outlined in the CANA submission to the RDGWG process on the development of a Code of Practice for Embedded Generators.

> **Recommendation**
> The distribution revenue rules should retain a requirement for DNSPs to submit their proposed negotiating framework for DG connection charges to the regulator for approval and subsequent publication. The rules should require the AER to be satisfied that this framework:
>
> - provides for a robust procedure for the negotiation of connection agreements, including information exchange;
> - requires DGs only to fund shallow connection costs, where shallow is defined as the nearest point of the existing shared distribution network; and
> - provides for DG proponents to be made aware of the options for the funding of deep connection costs or the connection constraint consequences of these not being funded (either by the DG or customers), including measures to ensure the provision of sufficient information to apply the regulatory test so as to determine the extent of any appropriate user-funded network augmentation.

We support the three main proposals of this recommendation. It must be acknowledged, however, that DNSPs have considerable bargaining power in negotiating market contracts with DG proponents. Whilst a DG project may be able to provide a benefit to the DNSP in an area of network constraint, the local DNSP has a monopoly control on that particular area of network constraint, and there may be in fact a number of other DG proponents competing for access to the market. The DG proposal may also be seen by the DNSP as competing with its own proposals for expanding its network. This places the DNSP in a position of considerable negotiating strength and potential conflict of interest, and needs to be acknowledged in the development of negotiation procedures.

The proposal to require DG proponents to pay only shallow connection costs is welcome, as is the requirement for DNSPs to provide adequate information to allow for the application of the regulatory test, and the potential cost of any upstream augmentation and/or network supply constraints. As mentioned in our response to 8.2.1.1, in order to ensure neutrality in the application of any network supply constraint, we would recommend that any network constraint algorithms used by DNSPs also be open and transparent, and submitted for approval by the AER.

8.3.1 Constraining energy exports

Recommendation
That further work be undertaken to investigate whether the non-price connection terms and conditions provided in Chapter 5 of the Rules create any impediments to the efficient utilisation of generation capacity.

We support the recommendation that further work be undertaken in this area, however stress that any assessment of efficiencies in the network also consider the range of additional benefits of DG, including reduced network losses. Whilst the NERA paper states that, as these costs are borne by the retailers and as such this issue is not the scope of this review, by constraining the export capacity of DG without regard to network losses a bias against DG projects is produced. Even if a DG proponent is able to access a benefit of reduced transmission losses through a price signal for generated electricity, overly constraining the export of electricity from the DG facility without regard to potential avoided losses prohibits access to these financial benefits and creates inefficiency in the system.

8.4.3 Avoided TUOS payments and competitive neutrality

Recommendation
The Rules should remove the requirement for DNSPs to make avoided TUOS payments to DGs. The Rules should continue to provide for both TNSPs and DNSPs to make network support payments to DGs, EGs or DSR providers, where the planning and regulatory test obligations under the Rules establish that such non-network solutions represent the most efficient means of alleviating a network constraint.

It is quite clear that DG, by definition, avoids the need for transmission capacity. It equally clearly follows that in the interests of economic efficiency and competitive neutrality, DG projects should have access to these avoided transmission costs, in order to facilitate DG projects that otherwise may not be established. This is why transmission use of system (TUOS) pass-through arrangements were established. We accept the presentation of the current problems surrounding the payment of avoided TUOS charges to DG proponents and that it is not sustainable to require DNSPs to pass through avoided TUOS charges to DG proponents if the DNSPs themselves do not in fact avoid these charges. The solution, however, is not to abandon a valuable mechanism but rather to fix the problems with it.

The simplest way to do this is to ensure instead that DNSPs do receive the avoided TUOS charges. One possible mechanism is for TNSPs to rebate avoided TUOS charges directly to DNSPs that are making TUOS pass-through payments to DG providers. In practice, this could be effected through an explicit reduction in TUOS charges paid by the DNSP. These avoided TUOS payments would need to be explicitly excluded from subsequent recovery by the TNSP through the operation of the ‘unders and overs’ account as applies under the TNSP revenue cap.

We recognise that, as NERA suggests, in principle the TUOS pass-through rule could be replaced with a requirement for DNSPs and TNSPs to consider non-network alternatives and to pay network support payments to DG and DSR proponents. In practice, however, there is little prospect of such an alternative arrangement being effectively applied. For such an approach to succeed, it is essential that the full range of benefits arising from DG and DSR projects are able to be captured by their proponents; these include improved supply reliability through generation diversity, improved power quality and reduced transmission losses, reduced greenhouse gas emissions, avoided distribution and transmission network augmentation costs and the ability to more efficiently provide electricity at times of peak demand, through a combination of network support payments and efficient and effective price signals via feed-in and demand reduction tariffs. If and when such an effective alternative arrangement is put in place then the need for the TUOS pass-through rule could be reviewed.

There is also an urgent need to streamline the calculation of the level of TUOS pass through to be paid. Currently, this process typically involves protracted and inefficient negotiations between the DNSP and the DG proponent which, even where they are eventually resolved, usually result in DG providers receiving only a fraction of the average TUOS charge. If the direct recovery by the DNSPs of avoided TUOS charges were to be resolved as suggested above, then a pass through to DG providers of the full average value of TUOS charges could be adopted as the default in place of long-winded negotiation.

Chapter 9 – Further considerations

9.1.2 Direct load infrastructure

Recommendation
Where a direct load control facility is available at a customer’s connection point, consideration should be given to ways to ensure the controller of this infrastructure provides access (on reasonable or regulated terms) to that customer’s retailer, DNSP, TNSP or other DSR intermediary engaged by the customer for the purposes of load control.

A customer’s load is the domain of the customer, and the control of this load should ultimately always remain their domain. Control of this load should only be ceded to any other party with the full informed consent of the customer. As long as any agreements with the customer appropriately reflect this principle, this recommendation should be supported in order to allow other parties to make DSR offers to interrupt or otherwise manage the load with customer consent. This would help streamline direct load control arrangements and reduce costs for all parties, therefore we support this recommendation.

9.2.2 DG network connection information requirements

Recommendation

A review of the information requirements in chapter 5 of the NER is necessary to ensure that:

- DNSPs provide DG proponents with the information necessary to apply the regulatory test to a DG connection proposal;
- DNSPs provide information on the emergence of network constraints as well as areas of substantial under-utilised existing transfer capability in order to allow prospective DGs to identify and site in the best location by reference to:
  - alleviating network constraints (and potentially earning network support payments); or
  - maximising energy transfer capability without incurring additional deep connection costs;
- DG proponents reveal their intended energy export levels such that DNSPs can accurately assess deep connection costs and formulate any connection constraint conditions that are required to protect network performance where;
  - the DG proposal does not satisfy the regulatory test; and
  - the DG proponent chooses not to fund the deep connection costs.

We look forward to the forthcoming review of Chapter 5 of the NER to ensure the adequate provision of information by both proponents of DG projects and DNSPs. It must be noted that the present information asymmetries are heavily in favour of the DNSPs, and any requirement for greater transparency could only be beneficial to DG proponents. This is particularly the case with regards to areas of network constraints, where (with the exception of NSW and South Australia) very little information exists to aid DSR and DG proponents in planning suitable locations to establish projects.