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CUAC submission to AEMC Stage 2 Issues Paper: review of demand side participation in the National Electricity Market

This submission has been prepared by the Consumer Utilities Advocacy Centre Ltd (CUAC), an independent consumer advocacy organisation, established to ensure the interests of Victorian consumers, especially low-income, disadvantaged, rural, regional and Indigenous consumers are effectively represented in the policy and regulatory debate on electricity, gas and water.

The submission is in response to the Australian Energy Market Commission's (AEMC) *Stage 2: Issues Paper - Review of demand side participation in the National Electricity Market* (the Issues Paper).

CUAC welcomes the AEMC consultation approach which has allowed reference group members an opportunity to shape the issues paper.

In practice there is a lack of genuine energy service[1] provision in energy markets and subsequently energy related services are delivered far from efficiently. In part this is due to entrenched systems for energy delivery and a lack of incentive in the past to maximise service efficiency. Where markets are disaggregated, split incentives may further inhibit efficient service delivery as generators, distributors and retailers cannot capture the value

[1] Energy services include cooling, heating, lighting etc

of efficient service provision. Their incentives are typically aligned to maximising energy throughput and revenue, particularly retailers integrated with generation. Ultimately this manifests as inefficient investment in generation and supply infrastructure, i.e. where it is not needed.

New business models for delivering energy services are developing, such as the GridX model where distributed generation coupled with heat recovery allows more efficient provision of electricity (the product) and related services such as space/water heating and space cooling. However such models are not necessarily able to capture all the benefits of efficient service delivery, such as the avoided supply infrastructure costs a network business would otherwise incur[2]. So the problem is twofold. The legislative framework does not encourage incumbents to supply efficient services and it does not allow new market entrants to capture the benefits of efficient service provision. We see resolving these issues as fundamental to ensuring the national electricity objective is met. This submission details suggestions for how this can be resolved.

The cost of peak demand is a clear example of where the NEM fails consumers by providing inefficient services. The West Australian Government estimates the cost of peak generation and supply infrastructure at $3000 per kW[3]. One of the major drivers of peak demand in any network is air conditioning, yet anyone investing in efficient cooling service provision such as: shading devices; more efficient appliances; insulation etc, cannot capture the value of avoided supply infrastructure spending, they can only capture operating savings. This means any provider of efficient cooling services and products requires a consumer prepared to accept a long payback period, whereas if avoided infrastructure costs were recognised upfront, gains would be more immediate. More immediate gains also helps overcome two significant barriers to DSP – the need to commit significant upfront capital and the length of the payback periods – which have been widely identified as obstacles to consumers investing in efficient service provision. Appropriate frameworks for demand side participation will help overcome some of these barriers.

Passing through wholesale generation prices and time specific network capacity costs to customers will not resolve the lack of efficient service delivery. This is primarily because there are significant non-financial barriers - split incentives and information asymmetry. Split incentives occur in the residential property sector and the commercial property sector – where the vast majority of space is tenanted – because tenants or landlords cannot capture the benefits of energy efficiency investments. For the tenants, this is typically caused by the duration of the lease being too short to achieve a payback on the investment while for the landlord, energy cost savings made from energy efficiency investment can be hard to recover from tenants. Information asymmetry occurs because

[2] In theory, these costs can be recovered but in practice the monopoly power of the DNSP allows it to dictate terms of any agreement formed between it and the service provider (such as GridX)

[3] WA Office of Energy (2004), '*The impact of residential air condition on the Western Australian electricity system'* – can be viewed at http://www.energy.wa.gov.au/cproot/603/2759/Air%20conditioning%20paper.pdf

for typical owners and occupiers of residential and commercial property, energy efficiency is not well understood – it is not 'core business'.[4]

We believe allowing more 'cost reflective' prices to reach consumers without complementary mechanisms to facilitate efficient service delivery is likely to result in less risk for businesses in the NEM, more risk for consumers, and marginal efficiency gains – a poor outcome for the market.

It is also important to note that the production of a good or service at its lowest efficient cost at any given time, and efficient long-term investment over time may be contradictory pursuits. In the context of climate change, it could be said that building new, long lived polluting infrastructure that supplies electricity at least cost now while allowing it to offset environmental damage in the short term through purchasing pollution abatement, provides lowest efficient cost electricity in the short term. However in the long term, cheap abatement is absorbed, the market for pollution abatement tightens and its cost increases. Theoretically, in the long run, electricity may be more expensive under this scenario, than if more expensive, less polluting infrastructure was originally deployed.

This tension is central to market design and its influence on investment in energy infrastructure. If least cost energy supply in the short term continues to be prioritised, we risk significant future deadweight losses.

For this reason, we emphasise again the importance of accurately and predictably accounting for the value of emissions in decisions on infrastructure investment. The price delivered through an emissions trading scheme will only reflect the marginal cost of abatement at any given time. The price is also driven by the political will to set caps and allocate or auction permits which can change over time. So while an emissions trading scheme will provide low cost abatement, it does not reflect the true value to society of avoided emissions and does not necessarily support efficient long-term investment over time. To accurately value demand side participation and ensure efficient infrastructure investment over time, the value of avoided emissions must be accounted for and this is not resolved by an emissions trading scheme.

The approach of Ofgem, UK has been to establish a 'shadow' price of carbon dioxide equivalents. This shadow price is used when conducting impact assessments from policy and regulatory decision making. The price accounts for social and environmental costs associated with carbon dioxide equivalent emissions and provides a transparent, predictable price for CO2e emissions over time[5]. We strongly recommend that the AEMC investigate a similar approach.

The remainder of the submission is structured to reflect the Issues Paper.

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[4] International Energy Agency, (2007) '*Mind the Gap -- Quantifying Principal-Agent Problems in Energy Efficiency*', an executive summary is available at http://www.iea.org/Textbase/npsum/mind_gap_sum.pdf

[5] DEFRA, (2007), *'Guidance on the shadow price of carbon'*, can be viewed at http://www.defra.gov.uk/environment/climatechange/research/carboncost/pdf/HowtouseSPC.pdf

Economic Regulation of Networks

1. *The balance of incentives may not encourage the efficient inclusion of demand-side options*

We believe the service incentive scheme is important to ensure networks have high powered incentives for providing secure, reliable electricity but should not be used by network businesses to block DSP. We also believe demand side participation (DSP) is complementary to a service incentive scheme and that risks associated with DSP can typically be managed.

Network businesses have been deploying forms of demand side response for a long time. Off peak water and space heating, load shedding in response to emergencies, back-up generators etc are all forms of DSP regularly and confidently used by network businesses. DSP typically involves very simple and reliable technology deployed at scale with margins for error making its risk low.

Conflicting incentives occur when DSP provided by a third party has the potential to avoid or delay capital spending as this devalues the network businesses' Regulatory Asset Base (RAB). Typically, the savings made by contracting DSP are not sufficiently large to outweigh the lost value associated with not building regulated assets. In such a scenario, liability associated with DSP failure is likely to be passed on to the DSP provider as a way of blocking that DSP or a network business may reject a DSP solution based on perceived, not actual risk.

It is important to remember DSP providers are not regulated monopolies, they deal in real competitive markets and face real risks of business solvency. If their solutions do not work, they will not be chosen by network businesses and they will fail. That is, the market ensures DSP providers deliver efficient and reliable services. Network businesses, while they face business risks, are regulated monopolies. Their solvency is essentially guaranteed through regulation which affords them significant negotiating power.

The best way to address the balance of incentives issue is for the regulator to hold the network business accountable to its obligation to undertake the most cost-efficient investment – that is to ensure network businesses accept DSP solutions where they are reliable and where they deliver net benefits to consumers.

Liability should remain with the network businesses for service provision even if contracting DSP. This ensures the right incentives for both parties to test and prove the performance of the DSP solution. To ensure efficient DSP is not blocked, the AER must satisfy itself with solutions offered by DSP providers to determine whether or not rejecting them based on risk is warranted by network businesses. Only the regulator has the authority to cut through any gaming by network businesses that overstates the risk from engaging in DSP.

2. *The building blocks form of regulation may limit the incentives for innovation on demand side participation*

CUAC agrees that the rules do not provide sufficient incentives for network businesses to undertake research, development and innovation (RDI) on DSP initiatives. The approach taken in some jurisdictions of a revenue allowance for RDI may encourage some spending on RDI but we question the efficacy of this. Not only have revenue allowances typically been very small percentages of total spend (~0.02%) where DSP solutions are developed, there are still relatively weak incentives to implement DSP.

Furthermore spending on RDI for DSP, if given to individual network businesses, is likely to result in duplication of efforts across network businesses and hence inefficient technology development. If funds are to be made available for RDI, this would be best in a centrally administered fund that can co-ordinate between network businesses to determine their common needs and undertake RDI on their behalf. Pooling funds through one body in this way is likely to result in more value for money. Aggregated funds would also help test and demonstrate more complex and large scale DSP projects. Efficient investment in RDI is in the interests of all consumers as it ensures new technologies and systems are developed and deployed at least cost

3. *The form of price control may not facilitate efficient demand side participation*

At the most basic level, a revenue cap is likely to offer more incentives for DSP than a price cap, but it could not be said those incentives will be effective or adequate. Complementary mechanisms to provide incentives are essential, and we recommend the AEMC undertake further analysis on those mechanisms, which include:

- robust consumer protection regimes
- sound DSP targets
- financial incentives to undertake DSP (and penalties for ineffective investment)
- broader policy co-operation that recognises that efficient energy service delivery depends on a number of industries – notably the property industry.

4. *The structure and components of tariffs may not provide customers with efficient signals about electricity use*

In some instances, price signals may elicit DSP but we believe the power of price signals is overstated. Research into demand elasticity suggests consumers, particularly small-medium consumers, do not respond to price signals. These consumers have a preference for technology-enabled DSP facilitated by third parties for which the consumer can receive some monetary compensation[6].

[6] Red Jelly, (2008), '*Qualitative Assessment of Consumer Responses to the National Electricity Smart Meter Rollout Program*', can be viewed at http://www.mce.gov.au/assets/documents/mceinternet/Smart%20Metering%20CBA%20Phase%202%20Stream%204a%20-%20consumer%20focus%20groups%20-%20NERA%2020080222200803041532l6.pdf

This preference reflects the significant non-financial barriers to demand side participation that revolve around split incentives and information asymmetry. Efficient price signals on their own are likely to be a significant burden to consumers, while providing only minor efficiency gains.

It is important to consider that energy is an essential service, providing crucial social and economic infrastructure to communities. There are sometimes good reasons for cross subsidising within energy networks to ensure some citizens are not priced out of living in certain locations due to energy costs, and that a community's economic development is not unduly constrained. This is particularly true for rural communities. Efficient energy pricing may mean a society and economy structured to suit the idiosyncrasies of energy markets – a strange objective – that does little to recognise national social and economic needs.

Without significant complementary policies and programs, 'efficient' energy prices will only serve to disadvantage already marginalized citizens. Given the lack of these complementary programs, support of efficient pricing is an impossible task for consumer advocates.

Network Planning

1. *The regulatory test threshold may be limiting the ability for alternatives to smaller network augmentations to be considered*

We believe consultation requirements for non-network options are not effective as the sole mechanism to elicit or encourage demand side options, particularly for small scale projects. Our research indicates demand side participation is often an organic process and does not necessarily occur in response to network constraints. Furthermore DSP typically requires longer timeframes relative to network build options – aggregation of consumers is typically needed as part of a demand response which could involve contract negotiations, equipment testing etc, whereas a network build option is a simple engineering fix.

Reducing the threshold will not induce greater uptake of DSP, as it is only one of many reasons why small scale demand side participation is not implemented where it is efficient.

CUAC believes the most efficient and effective way to elicit demand side participation is with a probabilistic approach. Such an approach establishes a value for avoided infrastructure and compensates DSP measures based on the probability of that DSP avoiding or delaying infrastructure spending. In this way, DSP is not used to respond to a specific constraint, it is incentivised to avoid the constraint in the first place. Such an approach encourages uptake of DSP where it is efficient and overcomes barriers caused by the disconnect between network build timeframes and development of DSP solutions.

A rough example:

For instance, assume firm DSP at peak times is valued at $1,500kVa. Assume average spare network capacity is 10% (4kVa) and average peak demand growth rate is 2.5% (1kVa/pa). So on average, peak capacity will be breached in 4 years of unconstrained growth. Network upgrades are typically made to restore 10% spare capacity and cost $6,000.

A DSP investment is made today that reduces peak demand by 1kVa and it has a 5 year life, therefore it delays network spending by 1 year as a once off. The DSP delays spending of $6,000 by one year, in 4 years time and is valued accordingly.

If the DSP could not be guaranteed as firm, eg it involves PV, its value could be discounted further by the probability the DSP will be firm. Studies indicate PV typically provides 20-80% of its capacity at peak times, so for example, the value of a PV solution could be discounted by 50% of its rated capacity. Naturally, care must be taken to define the value of various DSP measures.

In this way, measures such as energy efficiency, distributed generation, load control technologies etc. could be rewarded transparently, fairly and consistently as they are implemented. This avoids costly and sometimes ineffective consultations on non network solutions, provides investment certainty for DSP providers and helps overcome barriers to DSP caused by upfront capital costs.

Under the current regime, the value of such technologies is not valued transparently – it typically relies upon negotiations with significant information asymmetries, it is not valued fairly – in many instances the value of avoided infrastructure provided by DSP is not recognised or valued inconsistently. Changing the regulatory test threshold resolves none of these issues.

2. *The planning arrangements may not allow for sufficient time for demand-side options to integrate in the planning process*

3. *Consultation on augmentation options rather than on the needs of the network may create a bias against demand side options*

We believe both are a significant barrier to DSP and are best resolved through the probabilistic approach described above.

Network Access and Connection Arrangements

1. *Arrangements for avoided TUOS and DUOS may under/over value demand management options*

As is clear from our earlier comments, CUAC believes that the way in which DSP is currently valued is inefficient, and so acts as a significant impediment to its implementation. From our research, the existing requirements for avoiding TUOS and

DUOS do not act as a significant determining factor in making the decision to invest in DG. Nevertheless we believe it is important to get methodologies for their calculation right.

2. *Minimum technical standards for connections to the network may provide a barrier to potential embedded generation options*

Based on our research, we believe this is a significant issue, particularly for generators over approximately 30kW. Uniform technical standards are difficult to develop and implement because requirements will vary depending on network characteristics of a specific location and the generation technology being deployed. The technical requirements for connection are often unknown until an application is made, because network businesses develop connection requirements on a case by case basis.

Uniform standards are not necessarily critical to ensure generators can connect at least cost. It is inevitable that some flexibility will be required to accommodate the particular circumstance of each connection.

We believe that an effective, low cost dispute resolution authority is the best way to ensure connection standards balance the needs of DG proponents and network businesses. The dispute resolution body must have sufficient technical capacity to assess the legitimacy of the connection requirements.

The other potential solution is to establish an independent authority that can manage the connection process. This authority would streamline connections by aggregating skills and avoiding disputes between DSP proponents, network businesses and consultants over technical network issues.

3. *Deep connection costs to the network may be a barrier to potential embedded generation options*

Costs directly attributable to a connection and shallow connection costs can be interpreted very differently. The ambiguity allows network businesses to attribute what may be deep connection costs to a DG.

To ensure consistency, the language of the rules must better reflect its intent. If the intent of the clause is to protect DGs from network costs beyond the physical point of connection, than the language should state this explicitly.

CUAC believes that DGs should pay for connection costs to the extent those costs are attributable to the connection and to the extent the DG benefits from works undertaken. However we recognise determining and validating connection costs that occur upstream from a connection point, that are attributable to the connection, are subject to significant information asymmetries. This makes determining costs open to the exercise of monopoly power by network businesses. To overcome this, clear guidelines and an independent dispute resolution mechanism with sufficient technical skills is required.

4. *Contracting arrangements for embedded generation may not reflect the network support benefits that can be provided*

We believe that contracting arrangements are a significant barrier to distributed generation. The fundamental cause of this problem is information asymmetry and the monopoly power of the DSNP.

We believe there are two developments that would overcome these issues. The first issue (information asymmetry) could be significantly ameliorated by establishing an independent authority able to process connection of distributed generators. Our research, attached as an appendix to this submission, highlights significant support for an independent authority to undertake a range of tasks including managing connections and resolving connection disputes.

The authority could have a range of responsibilities including: providing information to connection applicants on their responsibilities; undertaking power systems analysis work; and valuing the connection. Such an authority could also be responsible for establishing and administering the probabilistic approach to avoided network spending outlined previously in this submission.

We believe an independent authority has the potential to create significant efficiencies in processing connections by concentrating skills and resources. Currently, DGs and network businesses undertake separate, independent analysis on connection costs and technical requirements with the results often conflicting. This results in delays and costs that jeopardize DG projects.

We recognize the AEMC has a limited mandate with regards to this review. However projections for DG technology development combined with the groundswell of community concern over risks associated with climate change are already leading to surging interest and unsatisfied demand for DG. If there really is a commitment to facilitating DSP and, particularly, DG as part of the national energy market being developed, this is a policy option worthy of serious consideration. We strongly recommend that the AEMC recommend to the Ministerial Council on Energy that the creation of such an agency, either independently or within another government organization, be investigated.

The second issue – of market power - is best addressed through significantly enhancing the dispute resolution mechanisms available to DSP projects. The current arrangements at the State and national level are demonstrably inadequate, and require serious revision. CUAC's research demonstrates how a low cost dispute resolution body would be able to reinforce competitive discipline on network businesses that abuse their monopoly power when negotiating connection agreements. It may be that such a body would complement an independent authority that manages the connection process.

Low-cost and accessible dispute resolution is critical to overcoming the significant information asymmetry between DGs and network businesses, and the monopoly power of network businesses. Existing requirements to negotiate in good faith are not sufficient to level the negotiating power imbalance.

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Yours sincerely

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Beyond Free Market Assumptions: Addressing Barriers to Distributed Generation

by

Tosh Szatow

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CUAC
Consumer Utilities
Advocacy Centre

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A. Executive Summary and Recommendations

The Ministerial Council on Energy (MCE) is considering changes to the national regulatory regime to facilitate demand side response (DSR) and distributed generation (DG). In 2007, the MCE commissioned the Allen Consulting Group (ACG) and NERA Consulting (NERA) to recommend improvements to the National Electricity Rules for network planning and connection arrangements, to remove those regulatory impediments.

Based on CUAC's previous conversations with DG project proponents, particularly through CUAC's Rural and Regional Network, and the findings of research on regulatory impediments to DG (some funded by CUAC), we were aware of substantial obstacles to implementing DG. We were concerned that the ACG/NERA recommendations would not be sufficient to level the playing field for DG. CUAC pursued and received a grant from the National Electricity Consumers Advocacy Panel to test those recommendations against real world experience.

Based on our research we conclude that ACG/NERA recommendations, if implemented, would fall short of establishing network planning and connection arrangements appropriate for facilitating DG.

To test the ACG/NERA recommendations, CUAC interviewed eight individual, community and commercial DG proponents, five DG consultants and three distribution companies representing diverse DG project experience across Victoria and NSW. These interviews explored the network planning and connection arrangements currently in place that either hinder or facilitate DG. Through these interviews, we developed recommendations to address areas where ACG/NERA recommendations appeared deficient. We also asked DG proponents what measures or programs would facilitate their activities.

A summary of where we believe the ACG/NERA recommendations encourage DG, fall short of facilitating DG or fail to take account of unintended consequences is detailed below:

Pricing and information provision

Encourages DG

- Planning information can help level the playing field for alternative energy supply options by providing accurate forecasts of network constraints and opportunities for investment.
- Time of Use (TOU) pricing will signal when demand for energy is at its greatest which could encourage demand response, such as distributed generation.

Falls short of facilitating DG

- 5 year forecasts are likely to be educated guesses at best due to limitations of forecasting; they therefore act as weak signals to DG projects being developed to address specific network constraint issues.
- Many DG projects are developed in response to an identified energy resource as opposed to network conditions. As such planning information is unlikely to provide a powerful signal for such projects. When aggregated, such DG (and other DM) projects can reduce network demand peaks reliably, the value of which will not necessarily be captured through avoided TOU prices – therefore a more transparent mechanism is required for valuing this.
- There is no guarantee that planning information provided by distribution network service providers (DNSPs) will be timely or accurate, and there is no recourse if information is wrong or so delayed as to be of no value to a DG proponent.
- Key information needed by a DG proponent is cost of connection, network load profile and any additional works required to facilitate DG (e.g. switch/line/transformer upgrades etc). This is unlikely to be included in planning reports unless the business is obliged to provide it. While providing this information may incur a cost to the DNSP, without this information DG projects are unlikely to be developed in response to planning reports.
- Where multiple DG proponents seek access to spare capacity in the network, a more clear and transparent process is required to facilitate prioritisation of those projects.

Unintended consequences

- Customers should have the option to choose ToU pricing, as opposed to being allocated ToU tariffs as a default with interval meters.
- Not all ToU tariffs are equal: there is a need for a transparent process for setting, assessing and balancing the trade off between the effectiveness and welfare implications of ToU pricing.

Negotiating frameworks and dispute resolution

Encourages DG:

- Standardisation of contracts for different DG sizes welcome.
- Sets timelines for negotiation processes.

Falls short of facilitating DG

- Standardisation of contracts requires that size classification for DG is appropriate and connection requirements reflect complexity/impact of DG.
- Negotiation timeframes must be managed so they cannot be used to exclude more complex, but more beneficial alternatives to network augmentation.

- Processes need to be enforceable by an independent body with the capacity to penalize businesses for non-compliance.
- Dispute resolution needs to be low cost, independent and capture smaller projects where a significant amount of viable DG exists.
- Cost benefit analysis on network and non network options can be loaded to deliver certain outcomes - need to standardise key variables where possible.

Attributing value/costs, network access and technology development

Encourages DG:

- Financial incentive for trials and risk sharing may be made available.
- Continued provision for network support payments in building blocks.

Falls short of facilitating DG

- DG proponents pay for network studies with no guarantee results will be accepted by the DNSP – all the risk is with the DG.
- DNSPs often lack internal resources to model system impact of DG. This duplicates consulting costs and inflates connection costs.
- A 'free kick' on trials and risk sharing will not be enough to get implementation DG. Needs to be incentives and disincentives in place to encourage DNSPs to implement DG.
- Delays on installation approvals and meter supply create cash flow issues for installers who rely on installation certification to receive government rebates.

Recommendations

To address the issues identified above, we developed the following recommendations with reference to the relevant NERA recommendations in square brackets[]:

Pricing and information provision

1) To be of practical value, annual 5 year planning reports should include where capacity for bi-directional energy flow exists and what network upgrades would be required to facilitate DG undertaken in a particular network zone. DNSP's should be required to provide more specific guidance on the kind of non network solution that would satisfy their requirements (i.e. a DG of size xMW that can be dispatched with 1hr notice or DSR of xMW that can be dispatched at 1 hr notice with the relevant network zone)[1].
2) A DNSP should be required to reveal if multiple DG proponents are competing for access to the same asset (e.g. spare capacity in a network) and clarity is required on who should be prioritised for a connection offer.
3) Customers fitted with interval meters should have the option to choose TOU tariffs [AMI recommendation].

[1] As recommended by ACG/NERA, DNSPs should indicate the value of such a non-network solution

Negotiating frameworks and dispute resolution

4) Regulation is required to discipline the planning process to ensure that DG and DM providers are actively pursued for non-network alternatives and developed on long lead times, not ‘consulted’ on as a last resort.
5) A low cost dispute resolution mechanism is required to capture the many viable small scale non-network projects that cannot access the $10M capitalised expenditure threshold [Recommendation 8].
6) Regulation is required to discipline the negotiation process, ensuring tighter compliance with negotiating timeframe guidelines, particularly if standard connection agreement not pursued [recommendation 23].
7) That the feasibility of standardising key variables and/or methodology used in regulatory test analyses and cost benefit assessments undertaken by DNSPs be studied to avoid selective use of assumptions which have the potential to load certain outcomes. In particular, a standard for valuing avoided Greenhouse Gas Emissions is required [Recommendation 6].
8) Attention should be paid to the treatment of risk and liability within the regulatory regime, to provide greater clarity to DNSPs and DG proponents alike about responsibility in the case of network failure.
9) A DNSP should be required to indicate whether a connection application should be processed by another DNSP within 5 business days of a user’s initial enquiry [Recommendation19].

Attributing value and costs, access and technology development

10) Rules should not govern technology specific DG, rather system performance of any DG system implemented [large scale roll-out of PV]. Rebates and financial incentives for DG technologies should also follow this system performance approach.
11) A risk sharing/learn-by-doing fund for distribution companies should not be used to overcome barriers to implementing DG. With the right regulatory framework, that is with revenue decoupled from throughput, and certainty around cost recovery for DG and DSR, DNSPs will commit resources to trials as appropriate [recommendation 9].
12) Probabilistic standards should be used to determine the network support value of DG, where it is intermittent and/or not 100% reliable and/or not immediately alleviating a network constraint. These should be developed and used to value energy supplied to the grid by DG.
13) Time specific loss factors are required to fully account for the value of DSR where it occurs at peak times, as losses at peak times can be an order of magnitude greater at peak times than on average over the year [Recommendation 31-34].

14) DNSP connection standards should not require equipment performance to exceed Australian standards for that equipment

Project implementation and industry capacity

15) Governments should create and fund an independent authority and/or programs to facilitate the DG connection process by:

    a) Undertaking certified power system analysis work to avoid cost duplications across DG proponents and DNSPs;

    b) Building industry capacity through training and demonstrations on power system analysis (PSA) and the impact of DG on network performance;

    c) Developing a more efficient process for testing and proving reliability and safety performance of equipment not covered by Australian standards[2];

    d) Providing information to DG proponents on network connection procedures.

16) Jurisdictions should review the cost of the certification process for DG installers.

17) Installation approval processes must be reviewed to assess whether they can be accelerated to facilitate cash flow for installers and minimise commercial risks.

During our consultation process, it became apparent that significant issues beyond the scope of the ACG/NERA papers impede DG. These issues relate primarily to how DNSPs are incentivised financially. Without their resolution, interviewees generally felt that any recommendations would have limited impact on DG uptake. These issues are listed below:

Financial Incentives

18) Regulation is required to break the link between energy throughput and network revenue certainty[3] and ensure distribution companies have certainty around recovering costs incurred from implementing DG and other DSR alternatives

Competition discipline

19) A low cost accessible dispute resolution authority with sufficient knowledge, technical engineering skills and power to discipline DNSPs effectively, is required to facilitate competition around provision of energy supply, including DG and DSR options.

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[2] We note this also appears to be an issue in the gas industry. This is explored in the detailed explanation of recommendations

3 See ‘Win Win Win Regulating Electricity Distribution Networks for Reliability, Consumers and the Environment’, 2008 for more detail

B. Research Background

The Consumer Utilities Advocacy Centre Ltd (CUAC) is an independent consumer advocacy organisation, established to ensure the interests of Victorian consumers, especially low-income, disadvantaged, rural, regional and Indigenous consumers, are effectively represented in the policy and regulatory debate on electricity, gas and water.

Our interest in distributed generation was prompted by discussion at the CUAC Rural Energy Consumers Forums, in 2004 and 2006. Rural communities in particular have an interest in distributed generation where it offers the potential for improved supply security, quality and reliability of supply. This is because rural consumers typically suffer from line losses and supply outages disproportionately to metro consumers.

CUAC is also working hard to ensure Victorian consumers' interests are accounted for in national electricity market reform, including the opportunity to set appropriate regulatory frameworks for network planning and connection of DG.

The evolution of DG technology is being driven by many needs: reducing emissions from stationary energy supply; improving supply reliability; avoiding costly network augmentations; improving the efficiency of energy supply through cogeneration and so on. As technology increasingly meets community expectations for clean, renewable, economical and reliable energy, the demand for DG is accelerating. For these reasons, it is essential that rules affecting the implementation of DG enable the implementation of existing and future DG technology where DG offers consumers their optimal supply choice.

This work is in response to recommendations made in the joint ACG and NERA Consulting papers, released in August 2007 to the MCE Energy Market Reform Working Group: *Network Planning and Connection Arrangements – National Frameworks for Distribution Networks* and the NERA paper, peer reviewed by ACG, *Revised Demand Side Response and Distributed Generation Case Studies*[4] (hereafter referred to as the 'ACG/NERA papers').

Specifically, our concern is the impact the ACG/NERA papers may have on rule development by the MCE in the process of national reform. We hypothesise that the research fails to take account of complexities and dynamics that impede successful implementation of DG. It is important to note we do not contend the recommendations were wrong, but we hypothesise they are insufficient to bring about

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[4] the papers can be found at http://www.mce.gov.au/index.cfm?event=object.showContent&objectID=872DC4B0-F5C1-48FB-B002E70E10C8D70E and http://www.mce.gov.au/index.cfm?event=object.showContent&objectID=87342E98-D164-82E6-B829311C17022BF2 respectively

their objective – the objective being efficient investment in energy supply infrastructure.

It is critical to CUAC's constituency, particularly rural and regional communities who stand to benefit most from distributed generation, that rule development is informed by primary research. CUAC therefore sought funding from the National Electricity Consumers Advocacy Panel to test the impact recommendations made in the ACG/NERA papers would have on actual DG projects in order to inform and direct appropriate rule development as part of the national reform process.

This research is primarily designed to facilitate Ministers' and officials' consideration of the ACG/NERA recommendations, with the intention of informing the development of legislation and Rules that provide real assistance to DG proponents and consumers. There are other policy-making processes which this research should inform, primarily the Australian Energy Market Commission's review of demand side participation. At the time of writing that process has been focused mainly on transmission network incentives, but the findings will also impact on distribution regulation.

Research Methodology

The research takes the form of case study analysis. Each case study was developed to test the impact of the recommendations made in the ACG/NERA papers to the Ministerial Council on Energy (MCE) Energy Market Reform Working Group.

The case studies were identified and classified to reflect the case studies presented in *Revised Demand Side Response and Distributed Generation Case Studies* and to reflect the constituency of CUAC – in this context, principally rural and regional consumers. The case studies used in the ACG/NERA paper were not revisited for detailed interviews, although original papers detailing the outcomes of the Newington Village and Kogorah large scale PV projects were reviewed in order to examine some of the context for ACG/NERA recommendations. We also sought projects that represent diverse locations and technology to avoid unduly representing location or technology specific issues.

The following table summarises the case studies we identified and how those case studies relate to the ACG/NERA ones.

ACG/NERA CASE STUDY GAPS	ACG/NERA CASE STUDY	CASE STUDY USED BY CUAC
Rural/regional project overlay	Large scale PV rollout • 160kW PV connected to distribution grid in Kogarah • 780 1kW PV modules and 199 500W PV modules at Newington Village (data from 30 1kW modules only used in NERA analysis)	• 3kW PV installations – regional community • 2kW PV installations – regional community • MEFL solar cities • CEEM reports
	Large user with DG requiring grid back-up • Sugar mills in Qld with up to 5MW capacity of bagasse fired generation	• 35MW bagasse DG proposal in rural area • Residential gas fired DG project in metro area
Rural/community project overlay	Mid sized DG providing peak power and network support • Infatils Lonsdale power station – 20MW diesel peaking plant • Somerton Power plant in Victoria – 150MW gas fired peaking plant	• 1MW biogas in regional area • 4MW Wind in rural area • 6.6MW biogas in metro area
	Large DSR project to relieve CBD constraints • Energy Response with units of 100kW/h of interruptible load	• Energy Response Pty Ltd
	Large industrial engaging in demand side markets	• Energy Response Pty Ltd
Alternative to PV – small scale installations[5]	Not examined	• Cogeneration systems b/w100kW-5MW across diverse locations • Fuel Cells in metro areas
Near term DG technologies (under 50kW)	Not examined	• 3rd gen solar • Micro CHP • Fuel cells • Micro wind
Rural and regional DG installations (alternatives to PV)	Not examined	• 95kW wind in regional area • 150kW wind in rural area • Cogeneration in regional area

We believe the rural/regional classification of DG is critical to understand and account for in rule development as many opportunities for viable DG are in agricultural areas due to the availability of either concentrated agricultural waste or high grade renewable resources such as wind, solar and hydro.

Rural areas also stand to benefit disproportionately more than urban areas from DG as a way of countering supply losses and increasing supply reliability, security and quality. This means that common barriers to DG are likely to disproportionately affect rural consumers.

We do not expect any difference in PV performance or its impact on networks between a coordinated large scale PV roll-out within a network and an organically occurring large scale rollout of PV due to the aggregate effect of individual action. This contrasts to the approach taken in the ACG/NERA papers which looked at specific large scale installations on specific sites. We used the experience of individual PV installations to test what effect ACG/NERA recommendations may have on an organically occurring large scale PV rollout as well as revisiting the original paper used by ACG/NERA on Newington Village by Centre for Energy and Environmental Markets (CEEM).

Stakeholders selected for detailed interviews were sent a background summary of the project (Appendix A), a document containing the ACG/NERA recommendations (Appendix B) and a series of indicative questions for consideration (Appendix C). A face to face interview was then held to go through those questions and explore the expected impact of the NERA recommendations. Stakeholders consisted of one of the following groups:

- Project consultant organisations (5)
- DNSPs (3)
- Project proponents (8)

Upon completion of interviews, responses were analysed in order to discern common issues or themes. Specifically, we sought to determine which recommendations either hindered or facilitated DG projects. We then sought to understand any deficiencies in the recommendations.

As part of our research it became apparent that there were regulatory barriers to DG that went beyond the scope of the ACG/NERA papers and recommendations initially identified for review and analysis. We have aimed to take account of these regulatory barriers and document them as appropriate.

Based on our research and analysis, we developed an advocacy position which synthesised the lessons discerned. The advocacy position was peer reviewed by a steering committee consisting of Chris Dunstan of the Clean Energy Council and Brad Shone from the Alternative Technology Association. It was also subject to expert peer review by Scott Young of Infrastructure and Regulation Services Pty Ltd to review the validity and applicability of the advocacy position and provide advice as necessary.

The final report represents the view of the author only and not necessarily those of the steering committee or the peer reviewer.

C. Benefits and barriers to Distributed Generation

There is a growing body of research and data highlighting the value of DG and also barriers to its implementation. These barriers can be grouped into the following aspects: operational (including technological and financial) regulatory, and policy.

Sustainability Victoria[6] refers generally to barriers to sustainable energy technology uptake created by uncertainty over:

1. How a new technology or process will work
2. The actual costs and returns of implementing a sustainable energy project
3. The skills and expertise of the suppliers of technologies and services.

While these barriers may seem self-evident, they provide a useful framework for assessing the barriers to DG. An additional, less well understood barrier to understand is:

4. Market structures, including how markets are regulated, that impede the implementation of technology.

These four barriers have been the subject of significant research and discussion in relation to DG, specifically:

1. How does DG work? – Operational barrier
2. What are the costs and benefits of DG? – Operational barrier
3. How can we ensure the relevant skills exist to implement DG? – Policy barrier
4. How can we ensure that market structures for DG do not impede their implementation – Regulatory barrier

Operational barriers

Based on the significant amount of DG implemented around the world, the operational barriers to DG seem to have been reasonably well overcome. To cite some examples, recent demand management (DM) initiatives undertaken through the D-factor in NSW, which includes DG, demonstrated benefit/cost ratios of 3.8/1[7], highlighting the value of DG and DM.

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[6] See Sustainability Victoria web page at http://www.sv.sustainability.vic.gov.au/sustainable_energy_challenge/barriers.asp

[7] Win Win Win Regulating Electricity Distribution Networks for Reliability, Consumers and the Environment' Institute of Sustainable Futures, 2008

Another recent report shows the value of DG in ameliorating peak demand. NSW-based DG systems operator GridX recently published research highlighting the effect of their DG system on peak energy demand in households[8]. It showed that in 2007 on their Glenfield site, when averaged, each house drew just 1.5kW at their peak demand time. Most air conditioners sold to Australian households produce between 3–7kW[9], with a coefficient of performance in the range 2.0 to 3.5 (meaning that the cooling or heating output is 2 to 3.5 times as great as the power input[10]). This means air conditioner consumption is likely to be in the range of 0.85kW – 3.5kW, so Gridx's results underline how impressive the impact on peak network capacity can be. In essence, the system supplies weather sensitive loads (cooling and heating) using waste heat from a generator, meaning better network capacity utilization and low greenhouse gas emissions.

The Energy Users Association of Australia research into the value of demand side response, including DG, and conducted by Fraser Consulting Services clearly demonstrated that significant quantities of viable DG exist throughout the NEM[11].

In Germany, a collaborative research effort has resulted in the modelling of a network supplied by 100% renewable energy at a decentralised level, fuelled by a combination of wind, solar, bioenergy and storage technology[12]. The model shows that with appropriate forecasting and scheduling, a network can be supplied with 411TWh of renewable energy over the course of a year. Such research is breaking new ground in terms of our understanding of how networks of distributed renewable, intermittent but predictable energy can be applied in practice.

Other quantitative, modelled assessments of DG benefits and how they accrue have been undertaken internationally and are also worth outlining to demonstrate the range of positive impacts of DG. In 2003, Oak Ridge National Laboratory (ORNL) modelled some of the more difficult to assess benefits of DG for the US Department of Energy, including the value of reliability, emission reductions and avoided transmission and distribution investment[13]. They found that DG can reduce loss of load probability, reduce emissions and help delay or avoid investment in transmission and distribution infrastructure. It is useful to reflect on how these benefits accrue.

DG enhances electricity reliability and security of supply for a number of reasons. Principally, reliability is improved by DG when it reduces the loss of load probability (LOLP) or reduces the impact of loss of load. Essentially, this means that the likely impact of losing generation capacity is greater in a situation where energy is

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[8] See GridX submission to the AEMC on this issue at http://www.aemc.gov.au/pdfs/reviews/Demand%20Management/submissions1/013GridX%20Power.PDF
[9] See air conditioner sales data at http://www.energyrating.gov.au/pubs/2004ac1-background.pdf
[10] See air conditioner performance data at http://www.energyrating.gov.au/acstar.html
[11] See the report by Fraser consulting at http://energyresponse.com/uploads/demand%20side%20response%20in%20the%20national%20electricity%20market%20case%20studies.pdf
[12] More information about the modeling can be found at http://www.kombikraftwerk.de/index.php?id=27
[13] The report by ORNL can be found at http://www.ornl.gov/~webworks/cppr/y2001/rpt/116227.pdf

generated by a small number of large units in comparison to a situation where energy is generated by a large number of small units.[14]

Distributed generation can also improve reliability and security of supply to a site because it is less subject to outages caused by transmission and distribution failure. This is particularly true for rural and regional consumers who are often subject to outages and voltage variations arising from their position at the end of a long distribution line.

As discussed in the ACG/NERA papers, DG also provides the opportunity to avoid or delay transmission and distribution works, providing associated economic benefits. These accrue depending on the size of DG, the existing load within a network, the probability of the DG being available at peak times and the planning regime of the transmission and distribution company. The greater the size of DG relative to demand within the network, the greater the probability of the DG being available at peak times and the more immediate the DG's effect on transmission and distribution network building, the greater the benefit of DG in avoiding or delaying network augmentation works. That DG failure may require mains grid back-up is only problematic for network businesses if the failure occurs at peak times as network businesses structure supply infrastructure capacity for peak supply. This risk may be further reduced by local demand management tools such as interruptible load contracts. Quantifying some of this more difficult to capture value of DG appears quite feasible.[15]

Maintenance schedules for DG can be organised to avoid planned outages occurring at peak times. In this way, DG reliability to be available at peak times within can be maximized. The makes the network benefits of DG limited by logistical and contractual rather than technical issues. These issues can be overcome through technology and appropriate agreements between the network operator and DG operator. Fair and transparent frameworks for calculating and negotiating the costs and benefits of DG are critical to ensuring it is implemented where it is the most appropriate supply side solution.

Reduced emissions can be a third primary benefit of DG. The primary emissions affected by choosing distributed generation over centralised generation are carbon dioxide (CO_2), sulphur oxide gases (SO_x) and nitrogen oxide gases (NO_x). DG can reduce emissions through fuel switching and/or increasing the efficiency of energy supply by reducing line losses and/or harnessing waste heat. However DG does not always reduce the effect of harmful particulate pollution. Its impact depends on technology, how it is maintained and its location. This must be considered when weighing the potential emission benefits of DG. In particular, some forms of DG in urban regions have the potential to exacerbate the health effects of SO_x and NO_x emissions if not managed appropriately.

[14] This benefit is modelled on pg 26 in ORNL, 2003.
[15] See pg 33, ORNL, 2003

The Stern review, the most comprehensive review available on the social cost of carbon today, estimated that based on business as usual, greenhouse gas emissions have a cost of $US 85/tonne CO_2 (2006). While a definitive figure is subject to debate[16], this should not stop an attempt to derive and apply a reasonable value for avoided CO_2 when assessing the merits of DG projects, remembering the value of avoided CO_2 is not necessarily measurable by the cost of avoiding CO_2. That is, even though CO_2 may be abated for $15 a tonne, the value of this to society could be far greater, for example, $85t.

Regulatory barriers

We acknowledge that some of the regulatory barriers to DG are beyond the scope of network planning and connection arrangements as covered by the ACG/NERA papers. However given its significance we consider briefly here the role of regulating monopolies in creating an appropriate framework for competition around energy supply choice in the context of DG.

In essence, regulation is designed to ensure the behaviour of a firm with monopoly power emulates the behaviour of a firm in a competitive market. That is, regulation is designed to subject firms with monopoly power to similar pressures faced by firms who experience natural market competition. In theory, this should mean that services are delivered to consumers for least cost.

In a competitive market, consumers have access to choice. If they are not satisfied with a product or service they can choose to spend their money elsewhere. This, in principle, creates discipline for business owners to meet customer expectations.

Driven by concerns about the environmental impacts of stationary energy supply, supply reliability or rising energy prices, some consumers are turning to DG as a means of supplying their energy. It is a signal that not all consumers are satisfied with centralised stationary energy supply and the manufacturers of DG technology are taking notice. For instance, a study in the UK for the Department for Business, Enterprise and Regulatory Reform suggested that micro generation could supply households with over 30% of their electricity needs by 2050 just by allowing export of electricity for the same cost as importing electricity[17]. Innovation in energy supply technologies is making such predictions possible, if not probable.

However when a DG connects with the network, the DG proponent must come to an agreement with the DNSP on the terms of connection. The network operator faces no natural market discipline to provide a competitive offer to the DG, to ensure timely and accurate information provision, to improve its service over time to DG, and so on.

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[16] We note that the Productivity Commission in Australia recently internally reviewed the legitimacy of discount rates used by Stern to assess the cost of action/inaction on climate change. The subject of discount rates is not clear cut and appears to be primarily an issue of ethical judgment around how uncertain future damages and benefits should be valued.

[17] See more details at http://www.berr.gov.uk/files/file27559.pdf

The DG proponent is often geographically constrained by the location of an identified energy resource and so cannot choose to implement their project with a more favorable network operator.

The result is a significant power imbalance between the DG proponent and the DNSP where the DNSP can largely dictate the terms of the transaction, in the absence of appropriate regulation and enforcement such as standardised connection agreements. This creates a cost burden for the DG, in particular costs resulting from delays and incomplete or inaccurate information exchange. Ultimately, these costs affect the ability of consumers to choose their most efficient form of energy supply and the cost of providing network services to all consumers. Furthermore, the experience of some consumers may dissuade others from investigating competitive energy supply options. This reinforces the status quo around energy supply options and may result in inefficient investment in energy supply infrastructure.

Once a network asset is built, its value must be recovered regardless of how it is utilised so ultimately, it is consumers who bear the risk that a network build option is pursued, despite it potentially not being an efficient investment. This highlights the importance of network planning and investment decisions reflecting the needs of communities and ensuring network options are rigorously tested to confirm they are the appropriate energy service solution.

Based on our research, regulatory barriers to distributed generation revolve around the following critical concepts:

- Distribution companies often experience perverse financial incentives to maximise asset building and energy volume throughput
- Distribution companies do not face strong enough incentives to permit competitive network access or penalties should they obstruct competitive access
- The value of avoided emissions has not been clearly defined or used to determine which supply side alternatives are least cost or most beneficial.

The issue of financial incentive is created by the current regulatory regime in all Australian jurisdictions, albeit with varying impact given other factors (ownership of the DNSP, other incentive schemes etc). Essentially though, where DG supplies a home or business directly it is often a threat to the revenue base of the DNSP and so risks making sunk investments prematurely redundant. Naturally, DNSPs are inclined to resist DG where they can under this regulatory regime.

The issue of competitive access requires both incentives and disincentives to ensure sufficient motivation for a monopoly business to undertake a particular course of action. This is because that in the absence of a disincentive, a monopoly business can choose to act on incentives or guidelines, or not, without facing serious repercussions to its business. A disincentive forces the hand of a monopoly business in the way that market choice would force the hand of a business facing natural market competition.

On analysis of case studies developed for this paper with stakeholders from Victoria and NSW interviewed, it is clear that distribution companies face minimal incentive to undertake demand management activities themselves, or to facilitate such activities for others. More worryingly still, they also face minimal disincentive from obstructing competitive access to the network. The recommendations made in the ACG/NERA papers do little to convince those interviewed that competitive access to networks would be changed, should those recommendations be adopted. In the words of one interviewee:

> **"It comes down to luck if you get someone in your local DNSP who actually wants to help you."**

While these issues have often been attributed to the culture of a DNSP business, it is misleading to suggest that willingness to facilitate DG is a cultural issue. DNSP culture is in part shaped by its regulation. DNSP culture responds to the incentives and disincentives faced by the business. In the words of one distribution company interviewed:

> **"Why would we commit resources to something which loses us money?"**

And one project proponent:

> **"The DNSP is not the enemy; they just need the right regulation."**

The third issue of valuing avoided emissions was a subject of much discussion in our interviews. The primary mechanism available to the regulator and to market participants in determining the relative value of new network investments over $1million is the regulatory test[18], the key provisions of which are repeated below:

(1) An option satisfies the *regulatory test* if:
(a) in the event the option is necessitated principally by inability to meet the service standards linked to the technical requirements of schedule 5.1 of the NER or in applicable regulatory instruments - the option minimises the *costs* of meeting those requirements, compared with *alternative option/s* in a majority of *reasonable scenarios*;
(b) in all other cases - the option maximises the expected *net economic benefit* to all those who produce, consume and transport electricity in the national electricity market compared to the likely *alternative option/s* in a majority of *reasonable scenarios*. *Net economic benefit* equals the *market benefit* less *costs.*

Reasonable scenarios means scenarios incorporating reasonable and mutually consistent:
(a) forecasts of:
(i) electricity demand (modified where appropriate to take into account demand-side options, economic growth, **weather patterns** (our emphasis) and price elasticity);
(ii) the efficient operating costs of supplying energy to meet forecast demand from existing, *committed, anticipated* and *modelled proje*cts including demand side and generation projects;

[18] Details of the regulatory test can be found at http://www.aer.gov.au/content/item.phtml?itemId=715871&nodeId=feb158f9d190e6fa5fcbe360aea506da&fn=Final%20decision%20reg%20test%20v3.pdf

> (iii) the avoidable costs of *committed, anticipated* and *modelled projects* including demand side and generation projects and whether all avoidable costs are completely or partially avoided or deferred;

Sensitivity testing
(23) *Reasonable scenarios* under this test must encompass sensitivity testing on key input variables. Sensitivity testing may be carried out on the following, and should be appropriate to the size and type of project:…

> (j) market based regulatory instruments that may be used to address **greenhouse and environmental** (our emphasis) issues

Given the predicted future impacts of climate change and the impact this will have on energy supply and demand conditions[19], it is imperative that a cost of carbon indicative of the cost of inaction on climate change, is appropriated as part of the regulatory test analysis. This does not imply the Australian Energy Regulator (AER) should set the cost of carbon, but in assessing the merits of different supply options, the AER must consider a cost of carbon as a critical factor in network investment decision making. Naturally, this implies that where distributed generation results in CO_2 reductions, the benefit of this must be included in its economic assessment. Furthermore, regardless of the investment size, any cost benefit assessment of network and non network options by DNSPs should consider the value of CO_2 reductions.

Policy barriers

The most significant policy barrier to the implementation of DG is a lack of a clear policy objective relating to the appropriate role of small-scale generation within the national energy market. This is an important barrier because without a clear policy objective, DG and traditional energy production methods are likely to compete for prioritisation and in the short-term, this will lead to a significant commitment of resources to projects that may be made prematurely redundant. A clear policy objective that outlines a vision for the expansion/management of the NEM provides investment certainty to energy markets which will help create efficient investment in new energy supply infrastructure.

There is significant interplay between policy and regulatory barriers. Policy mechanisms can be useful ways to address the limitations of regulatory frameworks and vice versa. In the context of distributed generation, there is reason to suggest that policy instruments could provide useful ways to overcome some of the regulatory barriers faced by distributed generation in the near term.

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19 The risk of frequency and intensity of future drought is predicted to increase as our climate changes (IPCC, 2007). Climate change is also likely to increase the frequency and intensity of peak energy demand as well as increase losses across transmission and distribution networks (IPCC, 2007). These risks threaten the cost, reliability and security of energy supply in Australia. See this link for more details http://www.ipcc.ch/pdf/assessment-report/ar4/wg2/ar4-wg2-chapter11.pdf

In particular, a transparent fair price for energy exported to the grid has the potential to overcome significant regulatory barriers to implementing DG. This can be used to capture the value of DG - that has been so difficult to do to date through regulatory mechanisms - such as: recognising the value of avoided emissions; avoided losses; avoided peak network capacity usage; improved reliability and so on. These issues are particularly relevant for rural areas who suffer from unplanned outages, extreme line losses and poor power quality more than any other customer demographic. One interviewee noted poor power quality is a significant cost to their business in terms of lost hours of work and damaged equipment which Guaranteed Service Level (GSL) payments fail to adequately compensate.

A transparent price for energy exported to the grid provides a firm signal to energy markets about how the energy industry should be shaped in the long term. On this, policy makers face a distinct choice. They can continue to let the complex interplay of entrenched monopoly industries and emerging technologies and business models compete for preference of energy supply, or they can signal to the market a preference for its future shape. Without a positive signal for the future shape of our energy market, communities will continue to bear all the risk when making decisions about their future energy supply.

What follows is a detailed presentation of our research findings, including suggested amendments to recommendations made by ACG/NERA consulting on network planning and connection arrangements.

D. Overview of Research Findings

At the outset, we must make clear that interviewees' input will not be directly attributed, due in some degree to the sensitive nature of information provided by interviewees but largely because of the concern of DG proponents that their comments could adversely affect their relationship with the NSP, and so affect their current or future DG projects. For this reason, to attribute certainty to the various findings presented, the report uses the following scales:

- Universal consensus (100% of those interviewed)
- Broad consensus (80%-99% of those interviewed)
- General agreement (<70%-79% of those interviewed)
- General acknowledgement (<60%-69% of those interviewed)

Unless explicitly noted otherwise the percentages apply to the full pool of interviewees which consisted of:

- 8 x DG proponents
- 5 x DG consultants
- 3 x DNSPs

Interviewees were sent background material prior to interviewing. This included copies of the ACG/NERA recommendations and indicative questions to be asked in the interview. These questions were used to guide a broad discussion with interviewees and can be found in Appendix C.

It should be noted that the research surveys concentrated solely on the relationship between DG proponents and distribution businesses (DNSPs), given they are the network business that has the contractual arrangement with most DGs.

Overarching conclusions

There was broad consensus amongst DG proponents and consultants that distribution companies do not reliably deliver network connection services that meet the expectations of their customers. In particular, subjects interviewed expressed dissatisfaction with costly project delays caused by negotiating connection details, information exchange, correcting incorrect information provided, arranging meter installations and certifying connections.

There was a broad consensus that connection delays are affecting the demand for distributed generation, with only the truly committed willing to persist with projects in the face of costly delays.

There was also broad consensus that as the economics of distributed generation improves with technology development and new business models, the demand for DG will quickly outstrip the capacity of the industry, including network operators, to facilitate its supply and that this will hinder industry development.

Pricing and information provision

There was general agreement that market information about network planning is not the main driver of investment in distributed generation and/or demand side response. Indeed, network reports were regarded as of limited value in making the decision about whether to invest in DG. Reasons given for this were:

- lack of appropriate regulatory incentive for implementing non-network solutions if they are identified
- technical nature of the reports which makes it difficult to interpret for non-engineers
- lack of specific guidance on appropriate non-network solutions
- lack of information on any costs required to facilitate a non-network solution
- lack of active engagement and facilitation of non-network solutions
- relative immaturity of the market for non-network solution providers.

DG proponents were generally supportive of more detailed information being provided in network planning reports, primarily around the cost of any upgrades required to facilitate DG and an estimate of the value obtainable by a DG proponent for any DG implemented. However there was broad consensus that no amount of information exchange provision or guidelines on connection timelines would overcome the barriers to DG created by the lack of incentive DNSPs have to facilitate DG projects.

A project specific issue was also identified that could recur. Where two or more connection applicants are competing for limited network capacity, in light of the significant project development costs, it was proposed that distribution companies should be obliged to notify applicants of the situation. Clarity was also sought on which connection applicant is prioritised – the first to complete a connection application, the first to be offered a connection, or the first to complete a request to connect (or some other criteria)?

There was some discussion among project consultants of ACG/NERA's recommended compulsory allocation of TOU tariffs to customers with Advanced Metering Infrastructure (AMI). It was noted that not all customers would benefit from TOU pricing and that customers must therefore have the choice to opt-in to such tariffs. Furthermore, these project consultants questioned the need for TOU pricing to drive DG and other demand side initiatives.

Negotiating frameworks and dispute resolution

Amongst DG proponents and consultants interviewed, there was broad consensus that without appropriate dispute resolution processes (independent, low cost) there is very limited confidence that distribution companies could be held accountable to any rules developed out of the NERA recommendations. Frequent references were made to the natural monopoly power of the distribution companies and the negotiating power imbalance this creates when trying to connect DG.

Furthermore, many interviewees acknowledged the legal and technical complexity of DNSP and DG proponent obligations, such as safety and reliability requirements, remain beyond many individual DG proponents, exacerbating the negotiating power imbalance.

While DG proponents expressed a desire to avoid dispute resolution generally, (preferring a collaborative approach with DNSPs), they felt such a low cost, independent dispute resolution mechanism would help address some of the negotiating power imbalance created by the DNSPs' monopoly position and so discipline the negotiation process. It was noted that as precedents are established, costs of dispute resolution would also be reduced.

Lastly, some raised the potential that variables used in regulatory test analysis can be weighted to advantage one solution over another. In particular, there was broad consensus that a mechanism is required to value emissions caused by different supply options. Failure to do so may result in significant investment in infrastructure that may ultimately be unnecessary and costly.

Attributing value/costs, network access and technology development

There was broad consensus that while there is no transparent and fair method for accurately valuing DG, its development is restricted. It was proposed that the simplest way to address this was through bundling the value of DG, additional to the value of the delivered energy, into the network component of an energy tariff. The additional value could be drawn for instance from capacity to supply energy at a certain amount or at a particular time, as well as avoided losses, improved reliability, avoided network and generation capacity, avoided emissions, etc. Building that into the network tariff is important as that is the regulated tariff, so subject to oversight and hence more likely to be transparent and consistent.

Given the difficulty of determining and applying site-specific value for DG, there was general acknowledgement that probabilistic standards could be used to assign a value to DG. That is, the performance of various DG technologies can be reasonably predicted making it relatively simple to approximate the value of the energy it is likely to produce and the impact this will have on the network to be approximated.

There was broad consensus that technology-specific regulation of DG is inappropriate and that any generation system should be valued according to its performance. Emerging technologies and system configurations that will allow low cost energy storage, dispatchable small scale DG, etc should not be disadvantaged because of technology-specific rules.

There was also some discussion of the value of creating a learn-by-doing fund for DNSPs. Among those who raised the issue, including one DNSP, it was thought such a fund would not result in an increased uptake of DG and/or DSR initiatives. This is primarily due to the lack of appropriate regulatory incentives to implement DG and other non-network options. Furthermore, one DNSP acknowledged that should appropriate incentives exist, DNSPs are unlikely to need a learn-by-doing fund because they will commit the necessary resources to trials and technology development regardless.

Project implementation and industry capacity

A concerning result from our study indicated there was broad consensus that industry capacity issues are constraining DG and driving up connection costs. Two out of three DNSPs interviewed acknowledged they do not always have the internal skill-set required to undertake power systems analysis needed to process connection applicants in a timely manner. Interviewees highlighted that this results in costly engagements with consultants, delays in connections processing which exacerbate project costs and limitations to developing appropriate technical connection standards.

Industry capacity issues identified include:

- Lack of power system analysis skills in the industry
- Lack of an appropriate body to test and certify new equipment to Australian standards
- High cost and accessibility (particularly travel requirements for rural installers) of DG installer certification programs

While there was general agreement that an independent authority able to undertake power system analysis work could result in cost reductions, there were concerns raised by DNSPs over the practicability of creating such a body to do power system analysis, primarily due to sensitivity over network details. This issue is discussed in more detail in the final section – detailed discussion of recommendations.

Lastly, we are compelled to note the concerns raised by smaller DG installers over processes for recovering government rebates on PV installations. Rebate payment requires certification of system installation by the DNSP. However in practice, the delay between installation and certification can be significant. This results in significant cash flow issues for those who supply and install systems which can create a barrier to such services. One such provider was waiting on $75,000 of rebates, effectively covering the cost of this cash flow restriction. While he was able to do so, it is unlikely that many other small businesses are willing or able to carry risk of that magnitude.

Financial Incentives

There was universal consensus that the future national regulator faces major challenges in the immediate future, namely:

- Resolving the issue of appropriate financial incentive regulation to ensure the link between energy throughput and network profits is broken[20]; and
- Ensuring distribution companies have certainty around recovering costs incurred from implementing DSR.

20 See Institute for Sustainable Futures, 'Win Win Win Regulating Electricity Distribution Networks for Reliability, Consumers and the Environment', 2008 for more detail

One distribution company acknowledged that the lack of a regulatory financial incentive to undertake or facilitate DG and DSR means that it was unlikely to commit the resources required to implement it, even if a learn-by-doing fund was made available for technology trials.

Competition discipline

There was broad consensus amongst DG proponents and consultants that a low cost accessible dispute resolution authority with sufficient knowledge, technical engineering skills and power to discipline DNSPs effectively is required to facilitate competition around provision of energy supply, including DG and DSR options.

There is general agreement that only when these issues of financial incentive and competition discipline are resolved, will the recommendations have a practical impact on the uptake of distributed generation. This is because the business model of network operators relies upon building network assets from which they receive a guaranteed rate of return, i.e. building their regulated asset base (RAB). Demand side alternatives to network building are perceived as a threat to building more network assets and/or selling electricity through existing assets, therefore in the absence of appropriate incentives or penalties, it is rational for network operators to limit demand management unless the cost savings from deferred or substituted capital expenditure are more than the foregone return on the network asset that would have otherwise been built.

One distribution company acknowledged that at best, gross metering arrangements – where the total production of DG is measured as opposed to net metering arrangements where the difference between production and consumption is measured – are likely to make DNSPs neutral towards DG, as opposed to averse to DG. This is because the DNSP would be paid for all energy exported and imported, as opposed to the difference between the two only.

A summary of where we believe the ACG/NERA recommendations encourage DG, fall short of facilitating DG or fail to take account of unintended consequences is detailed below:

Pricing and information provision

Encourages DG

- Planning information can help level the playing field for alternative energy supply options by providing accurate forecasts of network constraints and opportunities for investment.
- Time of Use (TOU) pricing will signal when demand for energy is at its greatest which could encourage demand response, such as distributed generation.

Falls short of facilitating DG

- 5 year forecasts are likely to be educated guesses at best due to limitations of forecasting; they therefore act as weak signals to DG projects being developed to address specific network constraint issues.
- Many DG projects are developed in response to an identified energy resource as opposed to network conditions. As such planning information is unlikely to provide a powerful signal for such projects. When aggregated, such DG (and other DM) projects can reduce network demand peaks reliably, the value of which will not necessarily be captured through avoided TOU prices – therefore a more transparent mechanism is required for valuing this.
- There is no guarantee that planning information provided by DNSPs will be timely or accurate, and there is no recourse if information is wrong or so delayed as to be of no value to a DG proponent.
- Key information needed by a DG proponent is cost of connection, network load profile and any additional works required to facilitate DG (e.g. switch/line/transformer upgrades etc). This is unlikely to be included in planning reports unless the business is obliged to provide it. While providing this information may incur a cost to the DNSP, without this information DG projects are unlikely to be developed in response to planning reports.
- Where multiple DG proponents seek access to spare capacity in the network, a more clear and transparent process is required to facilitate prioritisation of those projects.

Unintended consequences

- Customers should have the option to choose ToU pricing, as opposed to being allocated ToU tariffs as a default with interval meters.
- Not all ToU tariffs are equal: there is a need for a transparent process for setting, assessing and balancing the trade off between the effectiveness and welfare implications of ToU pricing.

Negotiating frameworks and dispute resolution

Encourages DG:

- Standardisation of contracts for different DG sizes welcome.
- Sets timelines for negotiation processes.

Falls short of facilitating DG

- Standardisation of contracts requires that size classification for DG is appropriate and connection requirements reflect complexity/impact of DG.
- Negotiation timeframes must be managed so they cannot be used to exclude more complex, but more beneficial alternatives to network augmentation.
- Processes need to be enforceable by an independent body with the capacity to penalize businesses for non-compliance.

- Dispute resolution needs to be low cost, independent and capture smaller projects where a significant amount of viable DG exists.
- Cost benefit analysis on network and non network options can be loaded to deliver certain outcomes - need to standardise key variables where possible.

Attributing value/costs, network access and technology development

Encourages DG:

- Financial incentive for trials and risk sharing may be made available.
- Continued provision for network support payments in building blocks.

Falls short of facilitating DG

- DG proponents pay for network studies with no guarantee results will be accepted by the DNSP – all the risk is with the DG.
- DNSPs often lack internal resources to model system impact of DG. This duplicates consulting costs and inflates connection costs.
- A ‘free kick’ on trials and risk sharing will not be enough to get implementation DG. Needs to be incentives and disincentives in place to encourage DNSPs to implement DG.
- Delays on installation approvals and meter supply create cash flow issues for installers who rely on installation certification to receive government rebates.

E. Detailed Discussion of Recommendations

These research findings were used to develop the following recommendations. The relevant ACG/NERA recommendations are indicated in square brackets. The recommendations are explained in more detail below:

Pricing and information provision

1) *To be of practical value, 5 year planning reports must include specific geographic locations of constraints and underutilization – that is, details of network constraints should be coupled with network maps or some equivalent. They should also include where capacity for bi-directional energy flow exists and what network upgrades would be required to facilitate DG undertaken in a particular network zone. Should costs of such information provision outweigh benefits, alternative mechanisms should be sought to engage DG and DM on longer (5-year) time horizons [Recommendation 1,2]*

It is generally acknowledged that 5 year planning reports are likely to be indicative of future network conditions only, given the dynamic nature of changing network conditions. Furthermore, DG is typically not driven by network conditions, making network planning information of limited value. However if information is provided to the market on network details, it must be of sufficient quantity and quality to be of practical value. Information that either cannot be relied upon or is not in sufficient detail will only create unnecessary costs for network business and weak or mixed signals for DG proponents.

Key information required by project proponents includes:
a) capacity of network to handle bi-directional energy;
b) cost of any upgrades required to facilitate DG;
c) specific requirements that any non network solution is required to meet (i.e. availability, size etc) and
d) financial value that would be made available to a successful non network solution proposal and the performance standards (availability/dispatch time) required by the DG.

Where the costs of providing such information is likely to outweigh the benefits, it is highly desirable that alternative mechanisms exist to ensure DG and DM proponents and options are actively engaged and pursued at the network planning stage as opposed to at the last minute, prior to a network build deadline which we note has adversely affected some DG proponents in the past.

2) *A DNSP should be required to reveal if multiple DG proponents are competing for access to the same asset (e.g. spare capacity in a network) and clarity is required on who should be prioritised for a connection offer*

Interviewees raised concerns over the transparency of network connection negotiations. Specifically, DG proponents have unknowingly competed for access to the same network capacity, unaware that only one connection applicant would be able to gain access to the network without incurring additional connection costs. Some distribution companies have also auctioned spare capacity to DG proponents, which we view as a potentially inflationary way of determining access to spare network capacity. Such costs can significantly alter project economics. Accordingly, DNSP's should be required to reveal if there is competition for existing network capacity.

Clarity may also be required on which connection applicant should be prioritised and how delays on connection offers should be handled. Specifically, interviewees described circumstances where a connection offer was not made by a DNSP because they felt the DG proponent business model was not certain. However the lack of a connection offer and hence knowing the costs of connection impedes a firm business model being established. For this reason, clarity may be required as to the conditions under which a DNSP can withhold a connection offer and/or what penalties may apply should connection delays unreasonably impede DG projects.

3) *Customers fitted with interval meters should have the option to choose TOU tariffs [AMI recommendation]*

The recommendation for compulsory switching to TOU tariffs was generally poorly received by interviewees who acknowledged that while efficient pricing is a sound principle in theory, certain consumer groups such as retirees/pensioners - a fast growing consumer demographic - will be disproportionately affected by TOU tariffs and that adjustment assistance beyond education and information provision will be required to ensure they retain access to affordable energy supplies. Without appropriate adjustment mechanisms, such as significant financial assistance for energy efficiency measures, TOU tariffs are likely to cause undue stress and health issues within particular consumer demographics. Customers should therefore customers should have the right to opt in to TOU tariffs.

It was also noted by some interviewees that TOU tariffs are not the only way to create an incentive for DG or DM. The value of DG or DM can be captured through alternative mechanisms such as a fee for exported energy or one off financial payments. A fee for exported energy, if coupled with gross metering, has the additional advantage of providing greater investment certainty because the timing and volume of production is more predictable than the timing and volume of consumption.

Negotiating frameworks and dispute resolution

4) *Regulation is required to discipline the planning process to ensure that DG and DM providers are actively pursued for non-network alternatives and developed on long lead times, not 'consulted' on as a last resort.*

As highlighted by some DG proponents in interviews, due to the absence of appropriate incentive regulation, information provision at the planning stage can be used by DNSPs to shut out, as much as facilitate, DG and DSR alternatives to network investment. A mechanism is required to ensure DG and DSR options are considered as part of the planning process. This will help ensure that viable alternatives to network building are not shut out by unreasonably short consultation timelines.

The comment was made during interviewing that investment timeframes need to be better aligned with planning timeframes. Unforeseen load growth issues, particularly around new commercial and residential developments, can mean non-network build options are consulted on too late. When investments are being made for the long term, beyond 10 years, better forecasting and planning is needed to ensure efficient investment is taking place.

Alternatively, it may be recognised that the value of DG is not driven by its ability to defer a specific network spend. Rather, a probabilistic approach to its value could be recognised and a standard value assigned to all DG depending on its performance characteristics. This is considered further under recommendation 12.

5) *A low cost dispute resolution mechanism is required to capture the many viable small scale non network projects that cannot access the $10M capitalised expenditure threshold [Recommendation 8]*

Interviewees were cognisant of not wanting to create unnecessary regulatory costs, but it was universally acknowledged that the significant monopoly power of network businesses inhibits competitive access to the network and this is exacerbated by information asymmetries. Access to low cost dispute resolution, particularly where disputes are caused by unreasonable delays in resolving connection details, is critical to encourage competition, and hence least cost energy supply options, as many DG proponents do not have the resources to engage in protracted dispute resolution with a network business. Should such a mechanism exist, it is predicted the long-term savings would outweigh the costs, particularly as early precedents would help deter unnecessary disputes and streamline the resolution of disputes in the future.

6) *Regulation is required to discipline the negotiation process, ensuring tighter compliance with negotiating timeframe guidelines, particularly if standard connection agreement not pursued. [recommendation 23]*

Interviewees acknowledged that where implemented, standardised connection processes have been beneficial for micro DG (particularly PV systems up to 3kW) and would be beneficial for all DG projects. Due to technical complexity, as the size of DG increases, so does the need for power systems analysis to determine the impact DG may have on local network performance which limits to a degree the amount of standardisation that can occur. However based on our interviews, negotiation of connection agreements and resolution of technical connection requirements can take up to two years, and in extreme cases even more. Such timeframes are unreasonable and pose a significant barrier to distributed generation. Without regulation to ensure timely completion of negotiation processes, DG proponents will continue to suffer costly project delays.

DG proponents can also suffer delays when getting basic questions answered, arranging for the installation of new meters and getting installations certified. For example, an interviewee detailed how one distribution company, despite having a policy for turning around new meter requests in 48 hours can take between 6-8 weeks. Another distribution company acknowledged that a 30 day turnaround on a connection agreement, as required by guidelines, is unrealistic given their resources committed to processing connection enquiries.

For these reasons, a mechanism is required to ensure that negotiation processes can be finalised more readily without compromising DG projects or network safety and reliability requirements. This could take the form of regulatory key performance indicators (KPIs), to enable the regulator to monitor such negotiations and ensure connection delays attract a financial penalty, and efficient connection processing a reward. Penalties and rewards must be sufficient to incentivise the required outcomes.

Alternatively, a specialist industry body could be established, or located in existing organisations, to manage the connection process, including undertaking of power system analysis. The industry body would work closely with DNSPs to understand their safety and reliability concerns around distributed generation. Distribution companies and DG proponents would share fees for use of the body and would be required to accept the technical requirements for connection decided by that body. Commercial negotiations would remain independent of the body. We note that DNSPs are sensitive to this idea and that they would ideally like to retain control over final connection approval. However if the industry body was established in close consultation with DNSPs, we have confidence that the technical skills and knowledge of the industry body would satisfy the DNSPs requirements. Further, some DNSPs are already using certified external consultants to undertake some of this work so in theory, should have no objection to a certified industry body doing this work.

This would help concentrate the skills required to undertake connections, remove cost duplications and remove some of the adversarial nature of negotiating technical connection standards.

7) *That the feasibility of standardising key variables and/or methodology used in regulatory test analyses and cost benefit assessments undertaken by DNSPs be studied to avoid selective use of assumptions which have the potential to load certain outcomes. In particular, a method for valuing avoided Greenhouse Gas Emissions is required [Recommendation 6]*

There was general concern over how cost benefit analyses can be used to determine the outcome of projects. It was generally felt that any standardisation of variables and methodology could assist this but that any such undertaking would have to provide flexibility given dynamic changes in market conditions.

Most importantly interviewees expressed that the cost of emissions, already priced and valued by large numbers of consumers (e.g. those who voluntarily choose greenpower) and accounted for in some business decision making, has to be accounted for in decisions about energy supply. It was stressed by many interviewees that failing to account for the cost of emissions now could result in stranded assets as the energy market transitions down an emission abatement path. One distribution company acknowledged that ideologically they have a strong desire to tackle environmental issues but do not have the financial incentive to take action. This is a major concern and warrants clear guidance on how a cost of emissions can be valued as part of network planning.

For these reasons, the feasibility of establishing a standard for assessing the value of emissions should be pursued in the interest of providing investment clarity to all businesses involved in network planning and non network energy supply solutions.

8) *Attention should be paid to the treatment of risk and liability within the regulatory regime, to provide greater clarity to DNSPs and DG proponents alike about responsibility in the case of network failure*

Distribution companies face significant financial liabilities for not meeting service standards. Interviewees noted that DNSPs have attempted to shift liability unreasonably to a DG proponent within the network connection agreement. Where a DG is contracted to be available as a non-network supply option, the liability associated with the DG not being available can prohibit the DG from entering such a contract. While it is important that service standards are not eroded in the pursuit of distributed generation, there may be a role for capping the liability which can be borne by a DG in providing non network solutions.

9) *A DNSP should be required to indicate whether a connection application should be processed by another DNSP within 5 business days of a users initial enquiry [Recommendation19]*

It was unclear why NERA recommended a DNSP to notify a connection applicant that their application had to be processed by an alternate DNSP only 5 days after they had confirmed they would pursue the standard connection route or within 10 days for a negotiated connection. A DNSP should be able to inform a connection applicant within 5 days of their initial enquiry whether the application should be processed by another DNSP.

Attributing value/costs, network access and technology development

10) *Rules should not govern technology specific DG, rather system performance of any DG system implemented [large scale roll-out of PV]. Rebates and financial incentives for DG technologies should also follow this system performance approach*

It was noted by many interviewees that performance of DG systems are likely to significantly change over time. In particular, the use of low cost storage systems and/or remotely scheduled generation may influence how DG is valued both by consumers, aggregators and by network businesses. For this reason, technology specific rules and recommendations are likely to date relatively quickly and may hinder DG in the future. Therefore rules should be based on system performance, not system technology.

The flavour of this recommendation extends into associated government programs such as rebates for certain DG technologies and energy related grants. It was noted by some interviewees that the structure of some energy related grants programs and rebate schemes favor certain technologies, despite competing technologies offering comparable energy services - energy storage is typically disadvantaged. All rebates and financial incentives should be tailored to reward energy system performance as opposed to energy technologies.

11) *A risk sharing/learn-by-doing fund for distribution companies should not be used to overcome barriers to implementing DG. With the right regulatory framework, that is with revenue decoupled from throughput and certainty around cost recovery for DG and DSR, DNSPs will commit resources to trials as appropriate [recommendation 9]*

While the value of a learn-by-doing fund, which provides a pool of money for trialing non-network solutions for DG was generally acknowledged, interviewees raised concerns over the efficacy and equity of DNSPs being responsible for such a fund. The demonstration of non-network solutions does not necessitate DNSP funding, although naturally the results of any demonstration and the knowledge of how the solution works is useful to a DNSP.

Based on interviews with DNSPs, it appears that they continue to be concerned over the reliability of non-network solutions and one DNSP interviewed commented that reliability is typically the factor that stops a non-network solution being pursued. However significant knowledge and practical experience with DG and DM more generally exists both in Australia and overseas. In particular, many DG proponents interviewed have used the German experience to help them understand the value of DG and how it can be implemented. Given the significant experience and knowledge of DG and its ability to perform reliably, it is hard to acknowledge the validity of the reliability concern. With many working examples of DG already in operation, a learn-by-doing fund for DNSPs appears to have limited additional value.

Perhaps most importantly, it was acknowledged by one DNSP interviewed that a learn-by-doing fund is unlikely to bring about implementation of DG or DM in the absence of appropriate financial incentive. Furthermore, with the appropriate financial incentive, a learn-by-doing fund would not be needed – the DNSP would allocate resources to trials accordingly.

12) *Probabilistic standards should be used to determine the network support value of DG, even where it is intermittent and/or not 100% reliable and/or not immediately alleviating a network constraint. These should be developed and used to value energy supplied to the grid by DG.*

The ability for DG to replace or defer network spending is a subject of discussion in the ACG/NERA papers. In short, the papers conclude that if DG, such as PV, can fail at peak times, it should not attract network support payments, although the ACG/NERA recommendations suggest leaving open the potential for DG proponents and DNSPs to enter into agreements for network support payments on a case by case basis.

While an individual DG unit may fail at peak times, in a network of many DGs, the failure of a single unit is not likely to be significant. During interviews with the Centre for Energy and Environmental Markets (CEEM), authors of a paper used as a case study by ACG/NERA, the authors were surprised at the conclusion that PV cannot provide firm support for the network and, in effect, should not attract network support payments. In fact, the authors suggested PV can reduce the impact and loss of load probability from unplanned generator or network outages by reliably providing between 20% and 85% of its rated capacity at peak times depending on the load characteristics of the network and the orientation of the PV. Such a probabilistic approach to the value of DG is more appropriate than the simplistic view that if DG can fail at peak times, it has no value to the network.

Without a standard for calculating the value of energy exported to the grid, the value of any DG technology and the ability of the DG proponent to appropriate this value can vary greatly according to the bargaining power of the DG, the state of the network, the location of the DG, the DG technology, and so on. A transparent tariff for exported energy has the potential to simplify some of the complexities in valuing DG and can overcome the negotiating power imbalance faced by many DG proponents.

13) *Time specific loss factors are required to fully account for the value of DSR where it occurs at peak times, as losses at peak times can be an order of magnitude greater at peak times than on average over the year [Recommendation 31-34]*

Annually averaged loss factors do not account for the full value of distributed generation, particularly where it is available at peak times. During peak times, heat stress on transmission and distribution lines, combined with the increased resistance on lines created by higher demand means that peak losses can exceed average losses by an order of magnitude or more. Where DG supplies energy within a network at peak times, its value should reflect these time specific losses. Ideally, this would be reflected in the value of feed in rates.

14) *DNSPs connection standards should not require equipment performance to exceed Australian standards for that equipment.*

It was noted by some interviewees that DNSPs can create and impose safety and reliability standards that exceed Australian Standards for equipment performance. These standards add unnecessary costs to DG projects and erode their financial viability. Where a DNSP's standards exceed the requirements of Australian certifications, the DNSP should bear this cost. This would help avoid any unnecessary application of safety and reliability standards.

Project implementation and industry capacity

15) *Governments should create and fund an independent authority and/or programs to facilitate the DG connection process by:*

    a) *Undertaking certified power system analysis work to avoid cost duplications across DG proponents and DNSPs;*

It is acknowledged that network businesses bear the legal responsibility for network performance and that any new connection will be necessarily subject to approval by a DNSP. However the DNSPs interviewed do not always use internal resources to undertake power system analysis for new connections, choosing to engage external consultants instead, a cost often passed through to the DG proponent. Some DNSPs interviewed acknowledged that a lack of requisite resources makes meeting timeframe guidelines on connection processes near impossible.

Given that DG proponents also use power systems analysis by external consultants for connection applications, this is an obvious cost duplication that in combination with skill shortages in the industry, acts as a significant barrier to DG connection.

Exacerbating this issue is that network companies will not always accept work performed by an external consultant, typically using a short list of preferred consultants with whom they trust. This can result in delays caused by disputes over predicted impact and performance of DG on the network.

An independent authority which uses certified practices and consultants in line with DNSP expectations and available to DNSP and DG proponents alike should create significant efficiencies in modeling the impacts of DG and facilitating DG connections. DNSPs raised concerns over releasing network data for analytical work by an independent authority. However given external consultants already perform such work and that any body established would remain independent, it is not clear how this would be a significant issue.

One interviewee suggests that significant demand for DG is being driven by the property industry seeking to reduce the cost of bringing power to their site and reduce the emissions associated with building use. Both drivers have significant commercial value for the property industry. In considering the value of an independent authority, the needs of the property development industry should be consulted on.

b) Building industry capacity through training and demonstrations on power system analysis (PSA) and the impact of DG on network performance

Underinvestment in skills in this sector is principally driven by the lack of business imperative for distribution companies to develop these skills. One distribution company interviewed is investing in University based courses to ensure training exists, but such investment will not necessarily drive the industry capacity required to manage future demand for DG[21]. This is likely to result in sub-optimal outcomes where DG is not pursued, because installation costs are artificially high due to skill shortages and connection delays.

Should an independent authority be created to undertake power system analysis work, such an authority would be ideally positioned to undertake training and industry capacity development. In the event such an authority is not created, it is highly recommended that resources be committed to develop university based training programs across the country in this field.

c) Developing a more efficient process for testing and proving reliability and safety performance of equipment not covered by Australian standards

DG proponents regularly face costs associated with meeting safety criteria specified by DNSPs. In some cases, the safety requirements specified by DNSPs exceed Australian Standards or require the DG proponents to prove the performance of an

[21] Anecdotally, the DG industry is confident that individually owned DG technologies will be able to supply individual homes at parity to the grid within 5-10 years - some DG is already providing energy equal to or better than grid quality and cost through cogeneration and heat driven cooling cycles.

equipment manufacturer's warranty even when the technology has been proven to operate safely in other comparable international jurisdictions. Such exercises incur significant time and financial costs for DG proponents. An independent authority could develop a process for testing to a reasonable standard the reliability and safety of DG technology, and facilitating the development of common standards that could be used by DNSPs and DG proponents alike. Having individual DG proponents bear unreasonable costs of certifying equipment which stands to benefit the wider industry and community is inefficient and inequitable.

This problem is not confined to electricity network businesses. With installations of Gas driven turbines, the issue of Australian certified safety standards has also been raised. In some instances, this can be a greater barrier to implementation than electrical safety standards. When testing for electricity generating equipment, the independent authority must be able to deal with gas transmission and distribution businesses.

d) Providing information to DG proponents on network connection procedures

Community based and individual DG proponents raised the complexity of dealing with connection procedures as a significant issue, particularly for installations over 10kW. Some proponents benefited from eventually identifying and contacting an individual in their local network business that was able to assist, however they generally found distribution companies unwilling or unable to assist them through the connection process. One DG proponent reported that an individual from the network business actively discouraged connection of DG and provided a degree of misinformation to deter the connection applicant. While the report must be considered anecdotal, such an account is of concern.

In the absence of appropriate incentives for DNSPs to facilitate connections, an authority is required which can field DG connection enquiries and assist customers through the connection process.

16) Jurisdictions should review the cost of the certification process for DG installers

Certification processes for installers is a costly and time consuming exercise, particularly in rural and regional areas. In many cases, installers have to travel for over two hours each way, over a period of ten training days, to obtain a certification. This creates significant cost well beyond the actual price of the installation course. This reduces the pool of available certified installers, increasing risks associated with non-certified installations and the cost of certified installations. Ultimately, this leads to increased connection costs as installers seek to recover the cost of certification.

Greater oversight is required to ensure that certification programs are low cost and accessible to a wide range of installers, particularly rural installers who are most likely to suffer from any travel/time costs associated with certification.

Responsibility for certification standards lies with individual jurisdictions, but this – and other recommendations pertaining to standardization - would seem to be an opportune area for increasing consistency between jurisdictions, to facilitate uptake across the NEM. As such, it could be considered for inclusion in the work program of the Ministerial Council on Energy.

17) *Installation approval processes must be reviewed to assess whether they can be accelerated to facilitate cash flow for installers and minimise commercial risks (and impediments)*

Installations of grid connected PV systems are subject to final sign-off by DNSPs who provide a certificate of installation. So far as there is a delay between PV installation and the provision of a certificate of installation, there is a delay in access to rebates. While DNSPs generally have a policy for providing certificates of installations, timelines are not always met. For example an installer in Castlemaine has often been left over 2 weeks waiting for sign off on connections and is currently wearing around $75,000 of unpaid grants – significant cash flow risk for a small business.

Financial Incentives

18) *Regulation is required to break the link between energy throughput and network revenue certainty and ensure distribution companies have certainty around recovering costs incurred from facilitating DG and other DSR alternatives*

The issue of incentive regulation of network businesses to facilitate DG and other forms of DSR has been covered widely. A useful discussion is provided by Kaufmen (2007)[22], which summarises how the current building block approach fails to incentivise DNSPs to undertake the most efficient investment in network and non-network solutions.

As this report was not designed to detail or resolve the issue of incentive regulation and given the magnitude of resolving this issue, it is difficult to give the issue meaningful coverage here. Suffice to say that it is a core barrier to DG implementation and accordingly requires immediate attention by regulators. The review underway by the Australian Energy Market Commission on demand side participation should be able to address issues of market design, and we encourage the Commission to encompass broader incentives in its deliberations.

[22] The report can be found at http://www.esc.vic.gov.au/NR/rdonlyres/7B753CB8-21A9-43A0-8972-DC8DAC849F01/0/EnergyMarketPolicyandRegulatoryBarriers.pdf

Competition Discipline

19) A low cost accessible dispute resolution authority with sufficient knowledge, technical engineering skills and power to discipline DNSPs effectively, is required to facilitate competition around provision of energy supply, including DG and DSR options.

To ensure competitive access to the network and provision of energy supply options, it is imperative that the inherent negotiating power imbalance between individual DG proponents or emerging DG and DSR providers is addressed through a low cost, independent dispute resolution body with the technical capabilities to discern the difference between real and perceived issues affecting DG proposals. Without such a mechanism, guidelines for the actions of DNSPs are unlikely to impose any real market discipline comparable to market pressures.

This need is highlighted by the repeated connection delays faced by DG proponents and consultants caused by information asymmetry and negotiating power. Many interviewees acknowledged it is virtually impossible for a connection applicant to know if they have been gamed by a distribution company. If they believe they have been gamed, the lack of low cost, accessible dispute resolution and the prospect of subsequent backlash by the distribution company means they are unlikely to seek redress.

Each NEM jurisdiction currently has an ombudsman that could - if appropriately resourced – adopt such a role.

Appendix A. Project Summary

Background

The research is driven by CUAC's concern over the quality of recommendations made in the NERA Consulting papers to the Ministerial Council on Energy (MCE) Energy Market Reform Working Group (titled: "Network Planning and Connection Arrangements – National Frameworks for Distribution Networks" and "Revised Demand Side Response and Distributed Generation Case Studies", August 2007), which outlined a series of proposed changes to the regulatory framework to improve incentives for demand side response and efficient investment Distributed Generation (DG).

Specifically, our concern is the influence these papers may have on rule development by the MCE in the process of national reform. We hypothesise that the research failed to take account of 'real world' complexities and market dynamics that impede successful implementation of DG.

Project purpose

- Develop an advocacy position which facilitates efficient investment in DG by influencing the rule making process.

Project objectives

- Ensure the proposed amendments to the regulatory framework concerning distributed generation will serve end users as is intended
- Secure well-informed policy and regulatory development that reflects the needs of rural consumers and communities, and facilitates appropriate solutions to problems of reliability and quality.

Project methodology

The hypothesis will be tested by consulting with DG proponents directly, assessing the impact NERA recommendations would have on their projects, and whether those changes would have facilitated or removed regulatory impediments. We aim to cover a mix of project types from small scale DG (such as 1-2kW PV systems) to large scale community/ privately owned DG (such as the 4MW Hepburn wind farm).

Once the impact of the NERA recommendations on these real-life DG projects has been assessed, we will develop an advocacy position through stakeholder consultation, peer review by the project Steering Committee and formal peer review by an independent consultant.

Project Output/Outcomes

The primary output will be an advocacy position to the MCE/SCO which uses empirical data and primary research to build upon and improve, where appropriate, the NERA recommendations. The desired outcome is to influence the MCE/AEMC rule making process to ensure the regulatory framework provides the correct incentives to facilitate investment in DG where it is efficient.

Project Contacts

For all enquiries, please contact Tosh Szatow by email using toshszatow@cuac.org.au or by phone on (03) 9639 7600.

CUAC has received a grant from the National Electricity Consumers Advocacy Panel to undertake the research.

Appendix B. Summary of ACG/NERA Recommendations

Revised Case Study Recommendations

Large scale PV roll out

Rule recommendations

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;

- Where tariff reassignment restrictions are to be included in the Rules, these should be limited to principles that ensure tariff assignment and reassignment are based upon:
    - customers' usage and connection characteristics, i.e. the drivers of network costs; and
    - providing equal treatment to customers with similar usage and connection characteristics.

Recommendations for consideration beyond the revenue and pricing Rules

- 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.
- Further analysis should be undertaken on whether or not the current treatment of losses is consistent with promoting efficient distributed generation projects.

Advanced Metering Infrastructure (AMI)

Rule Recommendations

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

Recommendations for consideration beyond the revenue and pricing Rules

- 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.

Large user with DG that requires back-up connection

Rule Recommendations

- The requirement for the periodic review of side constraints should be retained in the initial Rules.
- DNSPs should be required to submit to the AER for approval and publish protocols for the assessment 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).
- 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.

Recommendations for consideration beyond the revenue and pricing Rules

- 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 standards and their relative costs and benefits as compared with deterministic standards.

Mid-size DG supplying peak power & network support

Rule Recommendations

- Provision in the Rules for the inclusion of payments made by DNSPs for 'network support' expenditure in the derivation of the building block revenue requirements 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.
- 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 for the transmission system.
- The 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 cost, 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 cost or the connection constraint consequences of these not being funded (either by 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.
- 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.

Recommendations for consideration beyond the revenue and pricing Rules

- It is important that jurisdictional standard setters be cognisant of the DSR and DG incentive implications of planning standards. Consideration should be given to the use of probabilistic planning standards and their relative costs and benefits as compared to deterministic standards.
- A review of the information requirements in Chapter 5 of the Rules 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-utilisation existing transfer capabilities in order to allow DGs to identify and sit 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 does not satisfy the regulatory test; and
    - the DG proponent chooses not the fund the deep connection costs.
- Further analysis be undertaken on whether the current treatment of losses is consistent with promoting efficient distributed generation.

Large DSR project to relieve CBD network constraints

Rule Recommendations

- 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 of 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.

Recommendations for consideration beyond the revenue and pricing Rules

- A review of the information requirements in Chapter 5 of the Rules 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-utilisation existing transfer capability in order to allow 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 does not satisfy the regulatory test; and
  - the DG proponent chooses not the fund the deep connection costs.

Large industrial user actively engaging in demand side markets

Rule Recommendations

- 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 (this should be limited to say 12 months).

DG project Questionnaire
on
National framework for distribution networks:
Network planning and connection arrangements

Recommendation 1

The Rules should require DNSPs to undertake an annual planning process and publish an annual planning report that sets out the outcomes of that planning process. The annual planning report should include:

- a 5-year forecast of potential constraints, together with preliminary estimates of the costs of network solutions;
- a forecast of areas of substantially under-utilised existing transfer capability;
- a forecast of average and marginal distribution loss factors for different points in the network over the planning horizon; and
- a description of the DNSP's compliance with their planning-related obligations, including:
  - a summary of case-by-case applications of the regulatory test completed in the previous year, and on the status of the relevant projects (and the status of any projects from previous years); and
  - the results of applying the regulatory test to projects below the threshold for a case-by-case process but that meet the threshold for transparent reporting and the status of the relevant projects (and the status of any projects from previous years).

The annual planning reports (and any other planning-related information) should be made public and available from a single point (such as the NEMMCO website).

Recommendation 2

The AER should be required to produce a statement of specific requirements that is given effect by the Rules that sets out the standard format and required contents of the annual planning report.

The Rules should set out the matters the AER's statement of specific requirements is permitted to address, which should include:

- requiring an accessible summary of where and when constraints are expected to emerge over the planning horizon and of the value of deferring the associated network augmentations (e.g. in $/kVA per annum terms);
- requiring an accessible summary of the extent of surplus capacity at different points in the network;
- requiring an accessible summary of the magnitude of current and forecast average and marginal distribution loss factors at different points in the network; and
- requiring a standard format for reporting on applications of the regulatory test.

Recommendation 3

For any project to alleviate a network constraint for which the network solution would require an estimated capitalised expenditure of $2m or more, DNSPs should be required to perform an economic cost-benefit assessment of that project (see recommendation 6). As part of this assessment, the DNSP should be required to consult publicly and be required to issue an RFP from potential providers of non-network solutions to the network constraint. The DNSP should be required to report publicly the results of its assessment immediately after its assessment has been completed, and also to summarise the outcomes of the assessment in its annual planning report (see Recommendation 1).

Recommendation 4

For any network constraints for which the network solution would require an estimated capitalised expenditure of $0.5-2m, DNSPs should be required to undertake an economic cost-benefit assessment of the project and publish the results in the annual planning report, without being required to issue an RFP or consult on the options. We observe that for network constraints for which the network solution would require an estimated capitalised expenditure of less than $0.5m, there would be no formal ex post reporting requirement: DNSPs would not be required to undertake an economic cost-benefit assessment of the project, to issue an RFP or to consult on the options. The ex ante requirement to identify emerging constraints in the annual planning report would, however, apply to projects of this magnitude.

Recommendation 5

The Rules should require the AER to issue a statement of specific requirements that sets out the contents of a Request for Proposals for non-network solutions to address an emerging network constraint and that sets out the process to be followed in issuing such requests.

The Rules should require the AER statement to require the RFP to include, at a minimum:

- the technical requirements that the non-network solution would need to meet;
- the estimated range of costs for network solutions and an indication of the resulting annual cost that a non-network solution would need to better in order to be selected; and
- an indication of whether the DNSP considers non-network alternatives to be a feasible solution for the project.

The Rules should require the AER statement to require the RFP process at a minimum to:

- provide sufficient time for proponents of non-network solutions to prepare their cases while allowing the DNSP, in the absence of a committed non-network project, to implement a network solution after a cut-off date; and
- ensure that the RFP process is be capable of being brought to closure, with the non-network solution either committed (and bound) to deliver in a reasonable period of time, or the DNSP free to select an alternative option. The Rules should require all RFPs to be published in the same central location as the annual planning reports.

Recommendation 6

DNSPs should be required to apply the standard regulatory test (rule 5.6.5A) when undertaking a cost-benefit assessment of alternative projects (requiring amendment to clause 5.6.2(g)) so long as it continues to provide the flexibility for the test to be applied in a manner that is proportionate to the size and scale of the project.

Recommendation 7

The DNSP's obligations to undertake the annual planning and reporting activities, and to undertake project evaluations, should be Rules obligations and able to be enforced through standard Rules-enforcement processes.

Recommendation 8

A dispute resolution regime based on rules 5.6.6(j)-(n) should exist in relation to the DNSP's conduct of a cost-benefit assessment (and associated RFP for non-network options) for particular distribution projects, which should have the following features:

- threshold – should be limited to projects that are new large distribution assets (currently projects whose total capitalised cost is $10m and above);
- parties to the dispute – extend to parties directly affected, which would include proponents of non-network options, end-users and agents on their behalf;
- scope of the dispute – should not be significantly limited;
- dispute resolution process – the AER should have the role of hearing the dispute and adopt a low cost process for this; and
- effect of the dispute – the current effect of the mechanism, whereby the DNSP cannot be directed in its activities, should be maintained.

Recommendation 9

The Rules should ensure that DSR/DG trials and risk sharing arrangements are encouraged in order to build trust and communication between DNSPs and proponents of non-network alternatives.

In addition, the regulatory framework should be reviewed to determine whether insufficient incentives are provided to DNSPs to invest efficiently in research and development, warranting the development of a specific incentive mechanism in the Rules

Recommendation 10

Specify in the Rules the connection requirements that must be met by a user which include the requirement for users to:

- pay the DNSP for the construction of any dedicated connection assets (where the construction of these assets is not contestable) and any extension works to the distribution system required to effect the connection; and
- comply with technical and safety requirements in relation to the customer's installation or equipment, ie, payment for extension assets, dedicated connection assets and compliance with technical and safety matters.

Recommendation 11

Schedules to Chapter 5 of the NER should be amended to include a definition of the technical requirements for small load, large load, micro, small and medium DGs.

Recommendation 12

The NER should define the standard connection services to apply to micro DGs.

Recommendation 13

The NER should set out the minimum content for standard applications in a schedule to Chapter 5.

Recommendation 14

The NER should:

- set out the minimum content for standard connection contracts in a schedule to Chapter 5 including a requirement for the DNSP to specify the number of days after the finalisation of the agreement that the standard connection will be effected;
- require the AER to approve the content of the standard application form and the terms and conditions specified in the standard contract and require the AER to apply the 'fair and reasonable' test when determining whether to approve the proposed standard contracts.

Recommendation 15

The NER should state that the negotiation framework developed in accordance with Draft Rule 6.7.5 and as modified should apply in the negotiated connection application process.

Rule 6.7.5(c) should be modified to include the following additional provisions which would require the DNSP to specify:

- a requirement for the exchange of technical as well as commercial information between the two parties;
- a requirement that when considering a connection application the DNSP is to use its reasonable endeavours to provide the user with the service it requires in accordance with the reasonable requirements of the user, including without limitation, the location of the proposed connection point and the level and standard of power transfer capability that the network will provide (currently Rule 5.3.6(d));
- any offer pertaining to a negotiated distribution service to be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER and consistent with the technical requirement schedules contained in Chapter 5 (as applicable) and must not impose conditions on the user that are more onerous than those contemplated in these technical schedules (currently Rule 5.3.6(c));
- the cooling off period that will apply to any contract negotiated with vulnerable users;

- a requirement that when considering a connection application the DNSP must consult with any affected Distribution Network Users and NEMMCO (where relevant) if the DNSP believes, in its reasonable opinion, that compliance with the terms and conditions of those connection agreements will be affected, in order to assess the application to connect and determine:
  - the technical requirements for the equipment to be connected;
  - the extent and cost of augmentations and changes to all affected networks;
  - any consequent change in network service charges; and
  - any possible material effect of this new connection on the network power transfer capability including that of other networks (currently Rule 5.3.5(d)); and
  - the time periods for the commencement and finalisation of negotiations relating to negotiated connections once a completed application form is submitted to the DNSP for the alternative types of users and connection requirements.

Recommendation 16

Schedule 5.6 of the NER should be amended:

- to ensure that it can be utilised in contracts negotiated with small users, large users, micro, small and medium DGs;
- to include a cooling off period for those contracts negotiated with small users; and
- to include provisions which enable the connection agreement to be modified over time where both parties agree to changes in non-price terms and conditions including technical conditions which may require NEMMCO involvement) and where those changes have no associated cost effects.

Recommendation 17

The NER should require a DNSP, within five business days of receiving a user's initial enquiry:

- to advise the user whether there is a standard connection service that would encompass its connection requirements and if so:
  - supply the user with the relevant standard contract and application form; and
  - inform the user that they have the option of using either the standard connection service or negotiating an alternative connection service.
- to provide the user with a copy of the negotiation framework it has developed in accordance with Rule 6.7.5 and that has been approved by the AER which will come into operation if the connection service is to be negotiated;
- to inform the user of whether any aspects of the connection service are contestable;
- to inform the user of any additional information required which is of the kind specified in Schedules 5.4; and
- to inform the user of the indicative value of the loss factor applying in the area within which the user is seeking connection

Recommendation 18
The NER should require a user in the connection enquiry phase to advise the DNSP whether it will be seeking connection via the standard connection service route or the negotiated connection service route.

Recommendation 19
The NER should state that where a user selects the standard connection application route the DNSP must:

- advise the user as soon as practicable, and no later than five business days after receiving advice from the user that it will be seeking the standard connection service route, if the application should be processed by another DNSP; and
- within five business days provide the user with any technical information necessary to process the application in accordance with the technical schedules in Chapter 5 to the extent that it holds such information.

Recommendation 20
The NER should require the DNSP to issue a connection offer and a standard connection agreement within twenty business days of receiving a completed standard application form.

Recommendation 21
The NER should allow a user (utilising the standard connection application route) two months to accept the offer otherwise the offer should be deemed to have lapsed unless the DNSP agrees to extend the offer.

Recommendation 22
The NER should state that where an application is for a negotiated connection service the DNSP must within ten days:

- advise the user if the application should be processed by another DNSP; and
- provide the user with any technical information necessary to process the application in accordance with the technical schedules in Chapter 5 to the extent that it holds such information.

Recommendation 23
The NER should:

- combine the technical, price and non-price negotiation phases currently set out in the application for connection and offer to connect phases;
- remove any provisions which will be captured in the negotiation framework specified in Rule 6.7.5;
- require the DNSP to commence negotiations with the user as soon as it submits a completed application form; and
- require both the DNSP and user to negotiate in good faith state that any negotiation relating to access standards must:
    - be no less onerous than the minimum access standard contained in the relevant schedules in Chapter 5;
    - not adversely affect power system security;

    - not adversely affect the quality of supply for other users; and
    - involve NEMMCO in an advisory capacity and accord NEMMCO twenty business days to inform the parties in writing of any advisory matters arising as a result of the proposed negotiated access standard.
- require the DNSP to develop an offer to connect which contains the information specified in Schedule 5.6 and specifies the outcome of any negotiation relating to access standards, connection charges, prudential requirements and any other terms and conditions within the time specified in the preliminary program or later if the access standards have been negotiated.

Recommendation 24

- The NER should allow the user (utilising the negotiated connection application route) two months to accept the offer otherwise the offer should be deemed to have lapsed unless the DNSP agrees to extend the offer.

Recommendation 25

The NER should allow, subject to a decision by the AER as to the form of regulation to apply to the provision of connection assets, a DNSP to recover from connecting users the cost of dedicated connection assets as well as extension assets for the sole use of a new connection that, but for the new connection, would not have been incurred – a connection asset charge.

Recommendation 26

The NER should adopt the terminology in Box 4.1 for the purposes of calculating a connection asset charge.

Recommendation 27

A compulsory connection asset charge should not include the cost of any shared network augmentation that may be required to service the load/generation output arising from a new connection. However, a connection applicant may also choose to fund shared network augmentation by negotiation between the DNSP and the connection applicant.

Recommendation 28

The NER should require the AER to develop a Guideline for the determination of connection asset charges. The Rules should provide that the Guideline include:

- a definition of a standard small customer connection asset that may vary for each DNSP, for which no connection asset charge may be levied; and
- a definition of the relevant connection point.

Recommendation 29

The NER should require the AER to develop a Guideline that provides a methodology for the partial repayment of connection asset charges when a new customer connects to an extension asset within 7 years. The Rules should provide that the Guideline include:

- an obligation for a DNSP to provide a repayment to a connection customer in the event a new connection utilises part of the previously dedicated assets;
- dispute resolution procedures;
- the basis for calculating the repayment; and
- a requirement that the asset becomes treated as a shared network asset at the expiry of the seven year period**.**

Recommendation 30
Provisions within the NER that currently refer to the recovery of network augmentation costs through a connection charge should be removed (ie, Rule 5.5(f)(3)(i) and Draft Rule 6.22(1)(b)).

Recommendation 31
DG should receive a DLF that reflects the amount of losses that the DG would avoid by being present and operating (i.e. a marginal loss factor). In contrast, customers would continue to receive a loss factor that distributes the losses to be recovered across customers in proportion to each customer's usage, where the losses to be recovered are the sum of the forecast of actual losses and the sum of the 'avoided losses' from DGs.

Recommendation 32
Marginal loss factors for site specific DG should be calculated on the basis of the forecast losses with the DG being present and operating as forecast, compared to the losses that would be forecast in the absence of that DG. For smaller sites, the distribution loss factor should reflect a marginal loss factor (averaged across the relevant geographic area), but estimated in a manner that keeps the computation burden to a reasonable level – for example, through the use of a 'rule of thumb' relationship between average and marginal loss factors.

Recommendation 33
The AER should be encouraged to require the price that a DNSP charges to determine a site specific DLF for a DG or a customer that is below the threshold in the Rules to be a regulated service (by listing the service in the Rules as an example of an alternative control service).

Recommendation 34

DNSPs should be required to calculate a separate marginal loss factor for geographic regions that are expected to suffer materially different levels of losses, and to combine geographic regions for this purpose only where they are expected to suffer materially similar levels of losses.

Recommendation 35.
A site should be treated for DLF purposes as a 'customer' when it imports, and a 'generator' when it exports, on the gross flows of electricity, requiring two metered connection points at a site that is a combined distributed generator and customer.

Recommendation 36.
Allow, but not require, the AER to develop an incentive mechanism for DLF management guided by the principles of:

- the need to ensure DNSPs' motivations for controlling and forecasting losses are aligned with the potential costs / benefits of changed losses or better forecasts; and
- the need for neutrality in deciding between network and non-network options Control of losses – rather than accuracy of forecasts – is likely to be of more significance to efficiency

Proposed clause 6.6.2 in the draft Distribution Rule appears sufficiently generic to accommodate a loss incentive scheme.

Appendix C. Sample Stakeholder Questions

1. Please briefly describe DG projects you have worked on:
    a. Size
    b. Location (connection point)
    c. Technology
    d. Date of implementation or expected completion date

2. What was the reason(s) for implementing DG?
    a. Improved reliability of supply?
    b. Meet peak demand?
    c. Save money
    d. Reduce emissions
    e. Any other reasons?

3. Implementing a DG project is affected by rules governing negotiations with distribution companies and regarding connection issues and sale of electricity exported to the network. Please describe your experience of negotiating with distribution companies on these issues.

4. If implemented, would this recommendation affect previous or current DG projects that you have worked or are working on?

5. If yes, how would the DG project be/have been affected? If no, why wouldn't the recommendation affect/have affected the DG project?

6. Based on your experience, what changes to the recommendation would you like to see?

7. Based on your experience, what are the main issues that need to be addressed to help DG projects succeed (for example negotiation processes with distribution and retail companies, certainty around financial returns, ability to get accurate/timely/competitive quotes for connection services etc)

8. Based on your experience and understanding, what emerging or near term DG technologies exist and what are their performance characteristics likely to be?

9. Would these recommendations accommodate or allow for these technologies? Are they likely to stifle or facilitate the implementation of new technologies?

Questions on specific recommendations:

- How important is information provision as part of network planning?
- What size of project is it appropriate to do a cost/benefit study on?
- What should be covered in the RFP

- How should negotiation frameworks be managed? i.e. the timing of information provision, compliance with guidelines etc
- How should value of network support be quantified and recognised?
- How should the costs of DG be allocated (e.g. network augmentation is typically smeared, should DG costs be smeared?)
- What performance characteristics are important for DG?

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