FINAL REPORT

Prepared for:

Total Environment Centre

Level 4, 78 Liverpool Street

Sydney, NSW 2000

Rule Changes and Other Means for Facilitating Demand Response (DR) and Distributed Generation (DG)

Prepared By:

CRA International

Level 31, Marland House

570 Bourke Street

Melbourne Vic 3000, Australia

Date: December 2006

CRA Project No: D08942-00

DISCLAIMER

TABLE OF CONTENTS

1. PROJECT BACKGROUND AND PURPOSE

In its Brief, Total Environment Centre explained the background and purpose of this project as follows:

The current National Electricity Market (NEM) structure and Rules are inappropriately focused on the supply of electricity at the expense of demand side or other non-network approaches. The current focus on large-scale generation and supply has resulted in:

- *enormous and unnecessary costs of inefficient network investment;*
- *hidden subsidies to new, remote generators;*
- *the erasure of accurate price signals at multiple points throughout the NEM, including transmission networks;*
- *the creation of a less reliable electricity system that is reliant on a few large generators;*
- *barriers to distributed generators and demand management providers; and*
- *a greenhouse gas emission intense system that contributes to climate change and a disproportionate risk of future carbon liabilities . . .*

The major focus of the project is to develop a Rule Change Package that addresses the above issues as part of an on-going effort to bring about a more efficient and sustainable NEM. TEC requires assistance in interpreting the Rules and finding points of entry for change in specific Rules – or additions to the Rules – that can be justified in the context of the Objective of the National Electricity Law. The aim is to insert consideration for DM and DG at the national level to capture issues with the NEM pool and the transmission regulation, and also in anticipation of the transfer of distribution network regulation to the AER.

2. STRATEGIC OVERVIEW

When the NEM was designed, the industry was run by utilities and dominated by traditional, large-scale generation and network divisions of the utilities. There was only limited interest in demand-side activities, and distributed generation was generally not cost effective unless it was a by-product of a co-generation facility. The design of the NEM aimed, in principle, to accommodate demand-side activities and distributed generation that were expected to emerge naturally from efficient pricing in the market. However, many of the detailed arrangements within the market were designed to ensure they were effective for the existing industry, and in practice failed in many respects to accommodate non-traditional resources. For example, there are detailed provisions for the connection and operation of market generators, but while network service providers are required to take account of and make use of the potential of demand response to reduce peak demands on the system, little detail is provided as to how they should go about doing so.

There have been a number of reviews and reports on the barriers to demand response (DR)[1] and distributed generation (DG), and each of these has noted deficiencies in the existing arrangements. We are, however, still of the view we expressed in our report to the Parer review[2] that, in the main, the high-level principles in the Rules are well ahead of their implementation, and accordingly, focus should be on implementation, rather than further changes to the substance of the market Rules. In many situations it is not necessary for the Rules themselves to be amended, but rather for detailed arrangements for implementation or other mechanisms to be developed that will ensure the high-level principles are realised.

This situation has both good and bad points for proponents of demand response and distributed generation. To the extent that major philosophical amendments to the design are not required, the task is simplified. But the devil is in the detail, and to the extent that realisation of the intent of the Rules relies on the discretion exercised by various parties – for example, in relation to technical standards for the connection of distributed generators, or the provision of information and commercial arrangements for demand response – it is important that guidance be provided regarding these matters to the parties involved.

---

1 The term 'demand response' is used in this report to denote commercially based activities undertaken by end-use customers to alter their usual use of electricity in response to price signals available at any one or more points in the electricity market, or program offers made by electricity industry or third parties outside such pricing mechanisms. It is similar to, but somewhat more restrictive than demand management, which can include changes in energy-use behaviour that is not compensated for in any way (and, hence, is not commercially motivated).

2 CRA submission to the Parer Review.

Previous reviews have made progress towards implementation of the principles, but that progress has been very slow. In this report we note how a number of what may seem relatively simple amendments to the Rules should accelerate implementation of the fundamental principles. Ultimately, however, the effectiveness of any Rules depends on their application by responsible parties, and their monitoring and enforcement by relevant authorities. It is our view that significant scope exists for more guidance to be provided to the parties, and for a more proactive stance to be taken by the relevant monitoring authorities.

Prescription vs. Principles

Where it is felt that the principle of a Rule has not been realised due to the failure or inaction of relevant parties to implement the Rule as envisaged, greater prescription is sometimes seen as the only alternative. In our view, this is not always the best answer. A balance needs to be struck between detail in the Rules and flexibility, and it is a matter of judgement about where the exact boundary between the two lies.

The change in governance arrangements that make the National Electricity Rules (NER) a statutory instrument rather than an approved industry Code makes it even more important that the balance between detail and flexibility not result in the Rules becoming overly prescriptive. When rules are overly prescriptive, transaction costs can rise, innovation can be stifled and unintended outcomes can emerge that parties are compelled, by law, to implement. In this regard we note that (a) the Draft Rules issued by the AEMC in February 2006[3] in relation to network pricing moved to strengthen the role of the Rules relative to the current position, (b) there was general support from stakeholders, including TEC in its submissions, for such a change[4], and (c) these positions were upheld in the Final Rule Determination.

Our preference is that the Rules should contain clear statements of (a) the intent of the Rules, and the roles and responsibilities of various parties, (b) sufficient detail to allow the parties responsible for application of the Rules to fulfil their roles, and (c) where appropriate, guidance to relevant parties regarding implementation procedures. To support this approach, monitoring of the operation of the Rules should pay attention to the qualitative implementation of the principles. The approach proposed by the AEMC for transmission pricing is consistent with our view, albeit shifted from a loose definition of the AER's role to a tighter one[5].

---

3 Available at www.aemc.gov.au.

4 The AEMC paper also provides a simple example of how prescription can produce unintended answers: footnote 151 notes that although the AEMC proposes a new dispute mechanism for resolution of disputes relating to price arising in commercial negotiations about negotiated services, its terms of reference prevent it from recommending that the new mechanism also apply to other terms and conditions.

5 Interestingly, in this case, the AER is responsible for both the implementation of some elements of the Rules as well as their enforcement.

It is important to note, however, that regardless of the formal Rules, the quality of implementation by individuals and organisations remains crucial, and this will remain the case under the amendments proposed by the AEMC except where problems have resulted from procedural matters such as the timetable, which are now to be prescribed.

In our view, the single most effective improvement in the overall arrangements for distributed generation and demand-side issues of interest to TEC would be to increase certainty about what the Rules intend and about how they are to be implemented.

Certainty has also been a key objective of the AEMC in relation to the Rules for transmission revenue and pricing, and one that TEC has also advocated. Increased certainty has two effects. The first is the obvious benefit that derives from improved understanding and knowledge of the market objective and processes on the part of network owners and regulators. This will reduce transaction costs. The second is more subtle, and is the more important consideration in leading us to conclude that certainty is the key factor. Increased certainty, especially through written statements, will result in the parties responsible for implementing the Rules and other arrangements being clear about how they are to meet their obligations well in advance of taking action, and as a result those actions being less likely to be inconsistent or lacking in rigour. For example, if such certainty is provided, how a distributed generation plant will be judged to contribute to network reliability and how it will affect the timing of further augmentations or arrangements for deep access will be known, and it will be reasonable to expect that those approaches will be consistently and transparently applied.

Statements about proposed implementation can then be studied in detail, and if appropriate, challenged in a timely manner. Amendments to the Rules to require such statements are relatively simple, and if the proposals for such statements are based on improved certainty for efficient investment, should be relatively easy to substantiate as compliant with the market objective, which is a necessary condition for acceptance by the AMEC.

The following sections consider demand response and distributed generation separately, although in a number of cases one provision will apply to both, for example requirements for network planners to consider non-network alternatives, which can include either distributed generation or demand response. In the case of distributed generation in particular, the position of potential investors seeking access from a network service provider in order to connect their generator will be different to the situation where a network service provider is seeking an investor (or investors) to provide non-network solutions to meet network reliability standards. In the first case the network is responding to requests for connection, while in the second it is (required to) seek offers to connect.

3. DEMAND RESPONSE

3.1. BARRIERS

The barriers to demand response and demand management have been comprehensively investigated and documented[6]. Without trying to re-create that literature here, it is reasonable to summarise these barriers as falling into four major categories, as discussed below.

3.1.1. Information and Practice

Barriers related to information and current practice in the NEM include:

- Limited awareness of DR opportunities and the technologies and strategies for capitalising on them – This is true throughout the electricity value chain, from generators, through network operators and retailers, down to customers of all classes.

- Asymmetry of knowledge between retailers and end users – Retailers have much easier access to (and readier understanding of) the wholesale market prices and price movements that are of critical importance to the value of DR and when that value occurs. This, in combination with the fact that it is very difficult (as discussed below) for almost any customer to negotiate payment for demand response outside the interest of the serving retailer to purchase it, creates a significant barrier to strictly customer-initiated DR.

- Lack of appropriate information for end users to assess the value of and requirements for DR – The information that is available to end users is often either too general to inform action, or too complicated, or assumes too high a level of understanding of the operation of the NEM to be useful to most end-use customers.

- Lack of required information for DR prospecting for network deferral – Even the information provided as part of the consideration of alternative network options generally falls far short of what is required in terms of timeliness and specificity.

- Lack of track record of DR in network applications – The lack of a track record of successful applications of DR in some applications (particularly deferral of network augmentation) makes it impossible for system planners and system operators to assess the reliability of DR. This creates a vicious cycle in which these industry specialists cannot rely upon DR because it has never been provided the opportunity to demonstrate its reliability.

---

6 For example, the reference list of studies that have identified and commented on these barriers that was included in the Terms of Reference for the MCE assessment of *Demand Side Response Policy Options* listed 19 such studies, and it was far from being a comprehensive list.

3.1.2. Regulation

Regulatory barriers include:

- Lack of adequate regulatory treatment of network DR costs — NSPs need certainty that costs incurred in pursuing DR will be recovered. These costs include the direct costs of planning and pursuing DR, and any return of and return on capital foregone due to reduced sales[7], but can extend to additional capex in the event that the DR approach is not successful and reversion to a supply-side solution is required. This last factor also raises the issue of prudency. Finally, the lack of an incentive to pursue a new approach (and one that is perceived by NSPs to be more risky) has also often been raised as a barrier.

- Mis-match of time frames in considering DR and supply-side investments for networks – Information on network needs is often provided based on the timelines required for network solutions. This often poses insurmountable constraints on the development of a demand-side solution, due to the different time scale needed for what is essentially a marketing exercise. In addition, current approaches for assessing the cost-effectiveness of DR in network applications require that the deferral value exceed the total cost of the DR option. This fails to take into consideration the potential of the same DR to contribute to the deferral of subsequent augmentations. This is most related to DR options which are based on long-lived capital assets such as some direct load control options.

3.1.3. Pricing

Pricing barriers include:

- Lack of appropriate time-based tariffs that are seen by end users – The lack of end-use prices that accurately reflect the changing cost of delivering energy at different times of day and different times of the year is a major barrier to demand response. It is a result of a number of factors including: (a) the accumulation meters that are still in widespread use for smaller volume customers cannot deliver these price signals, (b) even where interval meters are in use, most customers prefer flat or at least relatively simple banded price structures, and retailers that can deliver such price structures will have a competitive advantage in doing so. This also means that more cost-reflective pricing structures offered by NSPs can be re-wrapped by the retailer.

- Lack of half-hourly meters – As mentioned above, a significant contributing cause of the lack of appropriate time-based tariffs is the lack of interval metering in the small end of the market.

---

7 This is not an issue under a revenue cap. Even in a price cap regime, however, this barrier can be addressed without undue complexity, as IPART's d-factor has demonstrated.

- Low level of materiality of energy costs in end-user operations and aversion to risk – The lack of interest in time-differentiated tariffs mentioned above is a result of the fact that energy is only a minor part of the overall cost structure of most customers. As such, it is not 'worth' the effort that would be required by complex pricing structures.

3.1.4. Market Structure and/or Commercial Barriers

Market structure and commercial barriers include:

- Split incentives – The benefits of DR flow to different markets (i.e., wholesale energy market, ancillary services market, network reliability improvement, network augmentation deferral), and therefore to potentially different beneficiaries. Implementation by any party unable to access all relevant markets reduces the value of DR, and therefore the price it is willing to pay, and finally the amount of DR that will be obtained. There is no mechanism requiring market participants to cooperate in considering or implementing DR. As a result, re-aggregation of the benefits of DR requires the cooperation and willingness of a number of parties and can entail significant transactions costs.

- Captivity of DR to the serving retailer – End-use customers wishing to make their demand response available to the energy market have virtually no option for doing so unless their serving retailer is interested in this resource at a price that is cost-effective for the customer[8]. While customers can seek interest among competing retailers, this reliance on the serving retailer also serves to limit available DR to those customers with larger blocks of DR that require little or no capital or transaction costs.

- The net system load profile (NSLP) used in settlement by differences spreads shape risk among retailers – The use of a profile for market settlement of small customer electricity consumption is a consequence of the lack of interval metering. As all retailers settle this volume on the net system load profile, the benefit of any action by a particular retailer to improve the load shape of its small-end customers will be shared with all other retailers. As a consequence, retailers have no incentive to seek DR from small-end customers, even without consideration of the potentially significant transaction costs involved in doing so.

---

8 It should be noted that there is nothing in the Rules that precludes "selling" DR to someone other than the serving retailer. Reserve trader, ancillary services and network deferral are all potential markets for DR. DR can also be used in the wholesale market by generators equally to retailers (though they are likely to only be interested in larger blocks for DR). It is even possible to "sell" DR to a non-serving retailer, though it requires significantly more complicated contractual arrangements between the end-use customer and the serving retailer, as well as between the end-use customer and the third-party retailer (or aggregator), and has therefore not been undertaken in the NEM to our knowledge.

The exceptions to this are customers who are willing to be direct participants in the energy market (current market rules preclude this option for all but the largest end-use customers), and demand aggregators that are direct participants in the energy market. Only a very few of the former category exist, and none of the latter.

- Absence of either a firm short- or long-term price for DR – The fact that energy prices in the wholesale market can change at short notice makes advance notification of the value of DR difficult, and therefore its use more challenging than contractual instruments for the energy trading operations of the retailers. This factor can also lead to frustration among DR providers. The lack of longer-term prices tends to inhibit the potential for capital investment to optimise the amount or dispatchability of DR, as well as to increase transaction costs for retailers and demand aggregators.

- High transaction costs and potential stranded assets for investment in DR at the small end of the market – The high transaction costs (particularly relative to the per-unit amount of load reduction available) makes harvesting of the DR capability of low-volume customers problematic. This is exacerbated by the capital costs required to enable price response (which would require either interval metering and/or direct load control to reach significant levels). The commercial potential for such an investment has not yet been proven in practice, and in any case, there is no market participant with the required capital and standing with the customer base to provide these services. DNSPs could do so but would require a means for cost recovery of the asset investment.

3.2. Options to Address Barriers

3.2.1. Improved and Clearer Regulatory Treatment

There is significant scope for improving regulatory treatment of DR and making existing regulations that apply to DR clearer. The most important aspects of this are:

- Recovery of DR costs

- Recovery of lost margins on sales where DR reduces sales

- Prudency of DR undertakings and the performance measures to be applied

- The ability to recover additional costs associated with either the implementation of DR or the need to revert to a supply-side solution where DR resources cannot meet performance requirements.

Jurisdictions have only relatively recently taken action with regard to these issues, and, not surprisingly, their approaches have taken different courses. This provides the opportunity to assess the effectiveness and second-order effects of the different approaches. Such an assessment could help identify the combination of elements that would provide the greatest certainty of approach consistent with the intention of the NER. Of particular interest in this regard will be examination of the relative merits of the approaches undertaken by IPART in NSW, ESCOSA in SA, and the ESC in VIC.

NSW d-factor

The NSW d-factor provides certainty to DNSPs of the recovery of costs incurred in developing and implementing DR programs, and the recovery of lost revenue due to the implementation of DR programs. This has gone a long way in encouraging DNSPs to undertake DM.

Any similar approach adopted at the national level for application to NSPs should build on the experience and learning from use of the d-factor. Specifically, any such approach should seek to provide (a) recovery of direct expenses on the non-network solution (up to the cap of the value of augmentation deferral or the cost of the next cheapest means for ensuring conformance with service requirements), (b) recovery of lost revenue[9], (c) recognition of reduced return on capital as a result of opex/capex trade-offs, (d) prudency assurance, (e) continuity of these financial arrangements across determination periods, and (f) at least for a transition period, the ability to recover costs (but not returns) in the event that the non-network solution is subsequently found to be inadequate and a traditional network solution needs to be undertaken to ensure adequate network capacity and reliability[10].

ESCOSA's Explicit Inclusion of DM Funding in Price Determination

The Essential Services Commission of South Australia (ESCOSA) made explicit provision in its *2005-10 Electricity Distribution Price Determination* of $20 million in operating expenditure for ETSA Utilities to develop capabilities in network demand management and undertake pilot demand response programs. The decision to provide this funding was the outcome of a study commissioned by the regulator to determine whether network demand management or the roll-out of interval metering would provide a more certain means for reducing the capex required to meet short-duration peak demands on the state's electricity distribution network.

Funding for capability and resource development was provided to:

- assist ETSA in developing better information on appliance penetration, customer end uses (including the contribution of different end uses to peak demand at present and as forecast for future years), and the number of different types of customers within each network area, and
- trial a number of specific DR programs.

---

9 It is worth noting that under the revenue cap form of regulation that applies to TNSPs, item (b) above would not be needed. It is still a relevant consideration with regard to DNSPs involvement in DR.

10 Note that items (c) through (f) are not addressed by the d-factor, but are elements that would need to be included in a comprehensive regulatory framework to encourage DR.

The SA approach is very different to the NSW approach, but also has merit for consideration on a national level. It is important to note that the two approaches are not mutually exclusive and in many ways are reinforcing.

ESC (Vic) Provision for Recovery of Inter-Regulatory Period DM Benefits

The Essential Services Commission, Victoria (ESC), in its 2006-10 Electricity Distribution Price Review (EDPR) reviewed and specifically rejected the approaches undertaken in South Australia (explicit funding for network demand management capability building and activities) and NSW (the d-factor) based on (a) the higher costs these mechanisms will impose on customers in the short term, and (b) the fact that Victoria's pending roll-out of interval metering will provide a much better information base for (i) developing pricing signals to encourage demand response (and to ensure cost-reflectivity of prices in the absence of demand response), and (ii) accurate and effective consideration of the applicability of network demand management (NDM) to system augmentation needs. It assumed that the DNSP would recover any costs expended on NDM because it would only undertake NDM (or other non-network solutions) where the cost of doing so was less than the cost of the supply-side alternative. However, it also:

- Provided a $600k allowance (for the determination period) for NDM benefits that could potentially accrue in a subsequent regulatory period, and are therefore at risk of not being obtained by the DNSP, and required each DNSP to provide annual reports during the current regulatory period of its NDM initiatives and the outcomes of those initiatives.

- Stated that DNSPs will be allowed to keep the capex savings of all NDM undertakings for a period of not less than five years, regardless of when the NDM is implemented in the regulatory period. This provision was intended to significantly reduce the disincentive to DNSPs in Victoria for implementing NDM in the later years of any particular regulatory period.

Including DR in the Regulated Asset Base (RAB)

There needs to be a means whereby the cost and value can be assessed of allowing DNSPs to put capex associated with DR at the small end of the market into RAB. We do not believe this issue requires a Rule change, however.

Capex for DR at the small end of the market can relate to communications and controls systems, and in some cases equipment on the customer side of the meter. Asset basing of communications and controls systems would not require a Rule change; such investments have been made and asset based in the past.

In the case of DR equipment on the customer side of the meter, this would seem to be a prime candidate for treatment as a network support contract. Doing so would not require a Rule change either. In our view, the current arrangements would allow for it, providing there is a willingness on the part of the DNSP to employ DR and also an acceptance by the relevant regulator of the legitimacy of the particular expenditure. As noted, the Rules would seem to allow both and we are aware anecdotally of network support arrangements where non-network expenditures on the customer side of the meter have been included in RAB.

There has been a more general problem with the revised Regulatory Test of which this is an example, however. The Test requires assets to be justified using ***either*** the Reliability Limb or the Market Benefits Limb. Benefits of one test cannot be used in the other test. Consider the case of a communications and controls system that might be implemented by a DNSP throughout significant portions of its service area. It is unlikely that the full system would be needed in the first instance for reliability reasons. It is also likely that parts of the system not used for reliability (or used for reliability for a period of time and then no longer needed for that purpose) would subsequently be used to provide market benefits (such as an enabling platform for demand response in the wholesale market, or frequency control in the ancillary services market). Unless the market benefits or the reliability benefits justified it on their own, the investment would not be allowed.

This is clearly sub-optimal, as it prevents the implementation of a system with clear, if shared, benefits to the network and the market more generally. The AEMC has preserved the separation of the two limbs in its Final Rule Determination, but also noted that the Electricity Reform Implementation Group (ERIG) has proposed "integrating the two limbs of the Regulatory Test as part of a single Project Assessment and Consultation"[11] process, which could provide the basis for further changes to the Regulatory Test.

Prudency Reviews to Encourage Network Involvement in DR

Prudency reviews could be a means for penalising NSPs that were found to have given inadequate consideration to DR and/or other non-network strategies.

However, the most recent AEMC Final Rule Determination in relation to transmission regulation has confirmed that *ex post* prudency reviews will no longer be a feature of the regulatory regime for transmission. This was a significant element of the Determination on the Rule and we would not expect the Commission to adopt a different position with regard to distribution.

11 AEMC, *Final Rule Determination: National Electricity Amendment (Reform of the Regulatory Test Principles) Rule 2006*, 30 November 2006, p 41.

In transmission this places increasing importance on the conduct of the Regulatory Test and capex incentives. At least for now, this is the same position in distribution although the MCE has flagged a different approach in the future that, as we understand it, would not involve explicit regulatory tests. No details of the MCE alternative are available at this stage to our knowledge. This situation underscores one of the themes of our advice that efficient operation of the NEM and particularly the regulated sectors assumes that affected stakeholders are actively engaged in consultations and negotiations and make full use of the checks and balances built into the Rules for consultation, disputes, enforcement and negotiation.

AEMC's Transmission Revenue Rule Proposal Report

More clarity regarding the application of the Regulatory Test to DR could still usefully be provided. The following areas in particular require attention, and would most reasonably be referred to the MCE or the AEMC for consideration:

- The Reliability Limb requires that the total cost of options – regardless of who bears them – be included in the assessment. This may disadvantage DR where additional revenue streams may allow reduction of the cost claimed against the network use of the DR. For example, the cost of a DR program or option will not vary with the benefits derived from the DR. In the case of network applications of DR, there is a very good likelihood that the DR will be used for purposes beyond the network benefit it provides. For example, the provider of the DR is likely to also "sell" the DR to a retailer for use in the wholesale market. Requiring that the total cost of demand management arrangements to be exercised by networks be justified by the network benefit ignores the potential for other benefit streams that could provide the rest of the justification. If all costs are to be taken up, so should all benefits. Conversely, the test could simply require that the portion of DR costs that are to be paid for by the DNSP does not exceed the benefits the DNSP will accrue from the DR.

  In summary, more detailed definition of the costs to be included or provision for relaxation of the requirement for all costs to be included should be considered as a means for avoiding unintended barriers to the use of DR to defer network augmentation.

- The Reliability Limb also requires that the option has "a clearly identifiable proponent". It is important to ensure that this can be extended to multiple proponents in the case of DR.

- Clarification should be sought regarding (a) which of the two Limbs would be applied in the instance where an NSP was proposing either capex or opex in order to reduce a shortfall in meeting performance requirements (i.e., where the shortfall would be reduced but performance requirements would still not be entirely met), and (b) the applicability of DR and therefore eligibility of its costs for recovery in such applications.

While it is assumed that NSPs will meet service requirements and will use the Regulatory Test to evaluate and justify the costs incurred for doing so, we are certainly aware of situations where an NSP has operated outside reliability requirements and was unable to rectify the situation in the near term. Under such a situation, it would seem prudent to have a means for valuing any reduction in the shortfall in service requirements that could be delivered by a non-network solution. Neither limb of the Regulatory Test addresses a situation where the network cannot meet service standards, but is proposing to reduce the amount by which it fails to meet service standards through the use of DR or DG.

- The ability of DR to provide competition benefits, as defined in the Market Benefits Limb of the Regulatory Test, should also be sought. DR can reduce the market power of generators and potentially reduce pool prices. These benefits should be able to be counted in the Market Benefits Limb.
- The Market Benefits Limb also states that where an option enables the NSP to provide both prescribed and other services[12], "the costs and market benefits associated with the 'other services' should be disregarded". While it is fair that double dipping be precluded, it will also be important to ensure that there are no gaps that would undercount the benefits of DR. It will also be important to have reasonably clear and accepted means for allocating DR costs between the prescribed and other services provided.

All of the above points concern either issues of definition within or implementation of the Regulatory Test. None require a Rule change; all can be addressed directly with the AER.

Finally, as discussed earlier, there needs to be a means whereby the cost and value can be assessed of allowing DNSPs to put capex associated with DR at the small end of the market into RAB. Associated issues concern the circumstances and requirements under which an NSP can act as an agent or aggregator of DR at the small end (or other portions) of the wholesale energy and other markets for DR services, or whether the role of the NSP should be limited to provision of an open access platform for DR. These issues would most reasonably be referred to either the MCE or the AEMC.

12 Other (non-prescribed) services would be those that the DNSP could provide at a market (rather than set or prescribed) price. In the case of DR, this could include payments from retailers to the DNSP for acting as an agent to secure and deliver DR to the retailer for use in the wholesale market. Such payments would reduce the amount of cost recovery required from network users, thereby making DR more cost-effective. This is essentially the same issue as discussed in regard to multiple benefit streams in the Reliability Limb (see the first dot item in this section), and will require the same solution. In both cases, the exact level of "other benefits" that may be accrued from the DR are likely to have to be estimated at the time of the Regulatory Test. These estimated benefits would be used to apportion costs. Annual reporting could be used to track the magnitude of "other benefits" actually received by the network, and adjustments made to cost recovery where deviations from the initial estimates (in either direction) are material.

3.2.2. Improved Pricing Arrangements

Options for improving network pricing arrangements and price signals more generally include:

- The roll-out of interval metering at the small end of the market will provide improved means for price signals to be delivered. COAG is in support of these improvements and the MCE could be asked to consider requiring the jurisdictions to undertake individual or a joint assessment of the benefits and costs of interval metering using a methodology to be developed in advance.
- Retailers could be required as a licence condition to offer cost-reflective pricing options to all customers, and to publicise their potential benefits.
- Similarly, retailers could be required as a licence requirement to offer pricing options at the small end of the market in which network tariffs are included as transparent pass-throughs, with information on how customers can benefit from such arrangements.

We are not of the opinion that the latter two options would be particularly effective in addressing this barrier, and therefore do not recommend pursuing them.

Standard Offers versus Negotiated Prices in DR Programs

DR programs constitute a form of innovative prices. Of particular relevance to NSPs, DR programs allow the NSP to provide a price signal directly to the end-use customers, without the retailer having the opportunity to re-wrap and mask that signal. It is also the case that DR programs provide attractive price signals, in that they represent a means for customers to receive payments (or bill credits) rather than face the potential for cost increases, and do not entail any penalty for failing to act.

Within the realm of DR programs debate has arisen as to the relative advantages and disadvantages of standard offer programs, in which the NSP posts a price for demand or energy reduction that non-network service providers can simply assess, and then take or leave. Negotiated price programs (for example, bidding programs or negotiated tenders) are those in which there is not posted price, and the NSP and the non-network service provider must jointly settle on a price. They are more complex and place a greater burden on offerers.

The main virtue of standard tariffs is their simplicity and the fact that they reduce transaction costs for offerers. However, the trade-off for simplicity is that the standard offer will almost invariably result in (a) a lower quantity of non-network solution being offered than would be the case under bid or negotiated price, (b) a higher average price for the non-network solution obtained, and (c) overpayments to some providers.

In and of themselves, standard offers do not reduce asymmetry in bargaining positions – they simply remove the potential to bargain. Further, unless standard prices are produced through a mandated calculation procedure, they do not ensure a “fair” price. Even where they are regulated or are “fair” in their own right, standard offers limit benefits to non-participating customers. This may be worthwhile where the absence of a standard offer would mean that non-participating customers would receive even less benefit.

Standard offers are more appropriate where (a) costs per kW reduced are likely to be very similar across providers and (b) simplicity is a program design value. These considerations argue for the use of standard offers with smaller customers, but perhaps less so for larger customers where non-network solutions are likely to come from a wider range of approaches (with different underlying costs) and where the offerer is likely to be more technically and financially sophisticated.

Standard offers are a pricing mechanism. They are appropriate in many cases, and the best approach in some. However, they are an implementation detail, and therefore should not be mandated. DNSPs and TNSPs should be educated as to the appropriate use of this pricing approach. As such, they should be considered for coverage (though not mandated) in Codes of Practice. They would not be an appropriate subject for treatment in a Rule, legislation or licence.

3.2.3. Improved Information Availability

While the principle that network owners should investigate non-network alternatives is reasonably clear in the Rules, there are a number of ways in which operational performance in this area could be improved.

- In relation to Rule 5.6, standing methodologies for generic assessment of reliability of non-network options should be required. The methodologies should be required to be developed using normal consultation processes. The network owners would be obliged to develop the proposals, but organisations such as TEC would have a formal opportunity to shape the form of the assessment and it would be a breach of the Rules to not give adequate consideration to submissions. Factors such as notice and advertising periods and the nature of information to be provided should be included either in the Rule itself or in the methodology and would apply to all technologies providing non-network solutions.

- Information provided by NSPs to potential DR providers in response to opportunities for network augmentation deferral or network reliability performance improvement could be improved. For TNSPs this could probably be accomplished under Rule 5.6. For DNSPs the most fruitful course of action would be to propose that the AEMC and AER consider parallel initiatives to those proposed for TNSPs. Again, the specific information required to support effective DR prospecting could be developed through a consultation process open to all relevant stakeholders.

Codes of Practice

NSW has implemented a DM Code of Practice, and SA has implemented a DM Guideline. A Code for Embedded Generation is expected to be released soon. We note that such Codes have had very mixed results in terms of the amount of incremental DR that has taken place due to their implementation[13].

Where they are implemented, it is only logical that Codes should be subservient to Rules. The Codes themselves should have two functions:

- to provide the details of how Rules are to be implemented, and particularly where including these details within the Rule would make the Rule impracticably bulky; and
- to provide the details of how a party will from time to time exercise a discretion given to it under the Rules.

Again, because a Code should always be subservient to a Rule, a Code should never create an obligation or right, but may describe how an obligation that is created under the Rules is to be met or undertaken. The key test for whether something should be in a Code or in the Rules is whether changes to a Code that still satisfied the authorising Rule could affect achievement of the market objective. If the answer is yes then the provision should be in the Rules.

Based on the above, our view would be that Codes would rarely if ever be inserted within the Rules, thought they might be referred to. However, Codes do not have to be mentioned in the Rules in order to have effect or be effective.

If reference to a Code in a Rule is thought to have material impact on achievement of the market objective, a proposal should be put forward to the AEMC to this effect.

Greenhouse Gas Emissions Information on Customers' Bills

In Victoria, information on the greenhouse gas emissions associated with a customer's electricity consumption is required to be disclosed on the bill.

Requiring similar disclosure in the other NEM jurisdictions could be mandated by the inclusion of the requirement as a licence condition. This would have to be enacted at the jurisdictional level. Alternatively, a NEM Rule could be established requiring such disclosure. It is important to note in this regard, however, that a timeline for the transition of retail regulation from the jurisdictions to the AER (or other national body) has not been set.

---

13 In SA, despite the DM Guideline having been in place for over 3 years, not a single network DR project had been undertaken. As a result, in 2006, ESCOSA undertook a review of the Guideline with the intention of revisions to make it more effective.

Having said that, it is also important to recognise that in order for a requirement that greenhouse gas emissions statements appear on customers' bills to be in the Rules, even after retail matters are subject to national regulation, it would need to be demonstrated to the satisfaction of the AEMC that this inclusion was in the “long term interests of customers”. That is, the AEMC would need to be convinced that the requirement enhanced achievement of the market objective. More specifically, the AEMC would need to be convinced not just that the provision of greenhouse gas emission information provides benefits, but that providing that information on a customer’s bill provided benefits above and beyond other means for disseminating that information.

However, the AEMC would, in the first instance, need to decide if it was even entitled to take a decision about whether information about greenhouse gas emissions is valuable. This is not a trivial issue, and there is reason to believe that the AEMC might believe that it is not entitled to do so.

In sum, the inclusion of greenhouse gas emissions statements on customers' bills could be required via a Rule, but the road to such a Rule change has several checkpoints.

An important first step in determining whether this route might prove possible would be to assemble and review information on the degree to which such a feature on the bill would provide benefits to consumers not available through other information dissemination mechanisms.

3.2.4. Consideration of a Dedicated Fund to Build Track Record

A dedicated DR fund could address several of the barriers discussed above, including:

- Provision of funding for the development of network DR proposals;
- Provision of the means to establish the information base needed to support the application of DR to network needs; and
- Development of a track record of DR performance in multiple applications, including real-world information on the costs and benefits of DR.

There is ample precedent for the establishment of such a fund. The NSW Energy Saving Fund is one example, and there are numerous examples overseas.

It would be reasonable to recommend that the MCE consider (a) the applicability of such a fund to the NEM, given the degree to which DR has remained under-developed, and (b) if applicable, whether the fund should be funded by a levy on electricity usage (as is done in NSW) or by general tax revenue. The decision between the two will depend on the nature and magnitude of the benefits assessed to justify the creation of the fund.

3.2.5. Consideration of Possible Means for Providing a Firm Short-Term Price for DR

Development of firm short- and long-term prices for DR is likely to require further demonstration of the availability of DR on demand, which may be advanced through one or several of the other actions recommended in this section. However, the following initiatives could also usefully be undertaken:

- It is our understanding that the MCE will be sponsoring a study of possible means for establishing firm short-term prices for DR. This initiative should be supported, and the potential for each option to assist in the establishment of suitable financial instruments (for example, the use of DR as the physical backing for a cap contract) should be included as an integral part of the assessment.

- As part of the above or as a separate undertaking, it would be worthwhile to understand the prerequisites that a financial player would require of DR in order to see it as a physical basis against which to offer financial instruments that could be used to set firm prices in either the short- or long-term. These would presumably include factors such as response time, minimum block sizes, nameplate vs. delivered capacity and a track record of successful dispatch. However, it will be important to understand requirements from the perspective of financial players, as they could play a potentially important role in establishing firm, short-term prices for DR.

4. DISTRIBUTED GENERATION

4.1. BARRIERS

This section briefly summarises key barriers to distributed generation. The following section discusses the options to address those barriers focussing on changes in the NER.

- Disaggregated revenue streams – Distributed generation can provide a number of services and products ranging from network support, wholesale energy market sales and hedging and ancillary services. The ability to value and access these different markets can be important to establishing a business case for a distributed generation project.

- Differing technical requirements – The significantly different operating characteristics of distributed generation and networks mean that distributed generation is not well suited to meeting connection obligations that have been devised between networks and large generators.

- Deep connection cost allocation – The debate about the merits of deep connection costs and their allocation remained unresolved for many years, and posed a potentially significant cost impost on distributed generation.

- Planning statements – Network service providers are required under the Rules to issue statements annually that are intended, amongst other things, to identify the opportunities for non-network solutions in future years and also to give notice of individual constraints as they emerge. The content and timing of these statements is not well defined and there is scope for improvement.

- Pricing of network services – This has been and remains a major and contentious topic. However, we note that in respect of distributed generation individual contracts may be of more significance than tariffs.

4.2. OPTIONS TO ADDRESS BARRIERS

The NE Rules relating to distributed generation include specific requirements for relevant authorities to include consideration of non-network alternatives to enhance network capability. Recognition of the contribution of large and small generation is a long-standing and integral part of the planning and operating regimes of transmission, and where generation is present, for distribution. Ownership of networks and generation has now been separated and network businesses have been regulated under mechanisms that place stringent controls on and monitoring of their capital expenditure. The arrangements under the new regime were created by the existing industry participants and naturally crafted to work for the status quo with high-level recognition of what would be necessary to implement principles of open access. In parallel, generation technology has evolved to lower the unit cost of distributed generation, a range of environmental "externalities" have become important, and demand management opportunities have grown significantly. It is notable that the AEMC has not proposed material changes to the principles for determining the revenue of transmission service providers but has significantly increased the level of prescription in the Rules, thus highlighting that the major concerns it sees and that stakeholders have presented to it relate to implementation of principle.

4.2.1. Disaggregated Benefits

A relatively complex limitation concerns the ability of embedded generators to participate in the full range of arrangements in the NEM, for example in offering network support and ancillary service or energy. Rule 5.6.2 (m)(2) provides that a generator contracted to provide network support is to be registered with NEMMCO by the network service provider and may provide network support, but may not set spot price when it is constrained on under the contract. We are aware that in certain cases the generator has not been eligible to earn energy revenue under any circumstances and hence the business case for the use of network support fails compared to a network solution. The difference can be simply the way the contract is formed; that is, if it is formed so that the network owner/operator may call on the generator to suit network loading, it should not be prevented from running of its own accord at other times. We are not aware of whether this is a material problem but a Rule to require contracts to be formed to maximise the potential for the generator to earn other revenue streams in addition to network support would enhance the business case for non-network solutions.

The Final Rule Determination by the AEMC addresses this area in the sense that it allows for non-network solutions and appears to be aimed at preventing double dipping by referring to non-network resources solely to assist network reliability. We suggest this should be clarified to ensure that this provision does not inadvertently lock out non-network solutions that are only viable if multiple sources of revenue are available, but still achieves the objective of preventing double dipping.

4.2.2. Connection Costs

In the NEM the shared network can provide both Prescribed and Negotiated services.

The Prescribed component is the service (including physical assets) an NSP must provide to meet its obligations for reliability or that it can show provides market benefits. The AEMC has confirmed that only customers will pay for Prescribed Services, and that they must pay the full cost of these services.

The Negotiated component of the shared network is comprised of those services and physical assets that are provided for the benefit of a particular party, but were not needed in order for the NSP to meet its regulatory obligations or entitlements. Installation by the NSP of new protection gear required by the connection of a distributed generator is an example of a Negotiated Service within the shared network.

The cost of any Negotiated Service is arrived at through discussions between the NSP and the party requiring the service, but is also subject to a maximum price set by regulation. Negotiated Services are paid for in full by the party requiring the service. Assets that allow a generator to connect to the shared network are logically Negotiated Service.

While there is little or no debate about pure connection assets in the NEM being regarded as a Negotiated Service, there may be scope for changing or refining either (a) the definition of what is required for or additional to the shared network, and/or (b) whether and when a service that was initially a Negotiated Service should more logically become a Prescribed Service.

For example, we note that the connection of remote generators to the transmission system is routinely deemed to be a Prescribed Service, and is therefore paid for by customers. While it is certainly the case that the network is unlikely to have had to incur the cost of the connection of a distributed generator to meet its reliability requirements, it is also generally the case that once in place, the distributed generator enables the NSP to meet future reliability requirements to some degree. Therefore, it may be of merit to seek an investigation into whether the Negotiated Service for which the DG initially pays should at some point in time be converted to a Prescribed Service, possibly by the payment for it being set to represent a portion of the total cost, and it being made on a front-loaded sliding scale over a period of say five years.

4.2.3. Connection Obligations

The technical requirements imposed on new entrants have proven to be very problematic. There have been a number of improvements, all progressively enhancing the position for distributed generators. For example, changes to the South Australian Distribution Code in 2005 significantly relaxed the requirements for inverter-based technologies connecting to the network. However, there remains a requirement for significant negotiation and discretion on the part the DNSP with regard to other types of distributed generators. We understand the implementation of that discretion is regularly problematic. This is an area where prescription is unlikely to resolve concerns of distributed generators because a prescriptive approach will need to cater for the worst case, and although it may be possible to create different categories based on say capacity and technology, inevitably a prescriptive rule will need to handle the worst case. There will be many cases where the worst-case requirements will be unnecessary, suggesting that negotiation and case-by-case analysis will still be required.

We therefore propose an amendment to Rule 5.3 that would have the effect of requiring NSPs to justify each technical requirement. Again, our suggestion is for a subtle change and is intended to prevent NSPs starting with a standard (worst-case) list and access-seekers being required to argue against provisions in each case. Rather, NSPs would need to argue for each provision in each case. In order to avoid inefficiency for obvious requirements where a NSP wished to start with a minimum set, the minimum set could be subject to approval by the relevant Regulator. Depending on the approach of the Rule drafters, Rule 5.3.6 dealing with the offer to connect would be the appropriate sub-Rule to amend. We would also note that parallel amendments may need to be made within jurisdictional Distribution Codes to the extent that they remain relevant under the proposed changes to responsibility for regulation of distribution networks.

4.2.4. Deep Connection

Major concern has been raised by a number of parties, including TEC, about deep connection. The deep versus shallow connection cost debate raged for years, and has only recently been resolved (as discussed below). In response to the original debate about who should pay for the shared network (i.e., only customers, or customers and generators in some proportion), NECA proposed the concept of “beneficiaries pay” as a means for allocating cost responsibility. However, no satisfactory methodology to implement the concept was developed (i.e., an acceptable algorithm was never worked out for determining who was a beneficiary and to what extent), and hence the allocation of deep connection costs remained a regulatory quagmire.

More recently, the AEMC, in its Draft Rule in relation to transmission regulation, came down against deep connection as the locus for cost recovery. They further stated that, even if they had accepted deep connection, they would not have endorsed a “beneficiaries pay” approach in any case. The AEMC has held to these views in its Final Rule Determination. Based on this, arguing for deep connection in relation to distribution would require demonstration that there is some critical difference between distribution and transmission that justifies a deep connection approach to the former when a shallow connection approach has been taken with regard to the latter.

Even if an argument could successfully be made for deep connection costs in distribution, there would likely be other consequences of shifting cost recovery responsibility for the shared network away from consumers solely to include generators. For example, if there were a move to introduce deep connection and make generators pay some of the prescribed service costs, then things like TUOS pass-through might need to be changed, since customers would then not be paying the full cost of the network (and so would not be entitled to rebates based on the full cost). Further definition of how these changes might affect DGs would depend on the particular regulatory regime put in place.

There is scope (beyond this paper) to consider both the longevity of TUOS rebate and what comprises prescribed services over time. In respect of the TUOS rebate the argument can be made, for example, that over time, the avoided TUOS charge dissipates because the total network charge must recover the transmission system cost. Although TUOS is reduced initially, the effect goes away as tariffs are reset. If the tariffs are designed perfectly, the effect will be efficient, but there is a risk that the rebate can be lost in the reset, and its effect is therefore uncertain. The AEMC noted the question of the boundary between negotiated and prescribed services in its pricing determination, referring to work by VENCorp[14].

TEC has also proposed that a distinction be made on the basis of size of generator and that small generators should not pay deep connection but large generators should. TEC suggests this is justified as large generators generally will have less favourable environmental characteristics. Even if the responsibility for deep connection costs were to be re-assigned to generators at some point in the future, we expect there would need to be a clear, probably quantitative, case showing economic benefit for the Rules to distinguish between large and small generators as suggested. We note that the Rules for assessment of network projects currently distinguish between small and large network projects on the basis of likely expenditure in order to manage the costs of analysis, but not on the basis of technology. We also note that the “spirit of open access” should not be interpreted as *free* access. Recognition of fuel type would imply that the Rules should take account of what is an externality now and it would be unlikely that this could be done without wide discussion about the merits and precedents of such an action for the Rules generally. For example, should wind pay less than gas which pays less than coal, etc? We recommend that issues of discrimination on the basis of technology be considered separately from cost allocation – that is, technology should remain an externality in respect of network cost allocations. This will allow consideration of subsidies or other provisions in relation to technology to be treated on their merits and increase the probability of resolving both issues.

In our view the highest priority is to get certainty about whether deep connection is to be charged to generators. The recent AEMC Rule Determination provides this.

4.2.5. TUOS/DUOS Rebates

DR and DG can reduce the loadings on both transmission and distribution networks. In certain instances, this can justify the payment of rebates, where those reductions result in lower payment requirements from, say, a DNSP to the serving TNSP.

---

14 The AEMC has noted that further work is needed in this area, and VENCorp has undertaken some initial work to develop principles for such a transition. Until such work is completed it is not possible to propose any specific Rule changes regarding this matter. (See footnote 94 in AEMC *Rule Determination for Pricing of Prescribed Transmission Services* regarding VENCorp, Victorian Electricity Transmission Network Connection Augmentation Guidelines, August 2005.)

Our preference in such instances would be for the Rules to lay out the principles that would apply generally, and for a Code to be issued that provides detailed worked examples of how the rebate would be calculated for particular examples.

We note that required principles are already included in the Rules and have been considered by the AEMC in its recent reviews. We believe that the best approach that TEC could take would be to approach the DNSPs directly to get an understanding of how they interpret and apply the existing Rules. It might be good to ask for some worked examples. If, upon examination, the interpretation or application being undertaken by the DNSPs is either (a) at odds with the intent of the Rule, or (b) inconsistent across DNSPs, it would make sense for TEC to go to the AEMC with this information and seek a Rule change that requires the publication of a Code of Practice with worked examples to clarify the intent of the Rules in this regard and provide a means for ensuring compliance with that intent.

4.2.6. Planning Statements

The principle that network owners should investigate non-network alternatives is reasonably clear in the Rules. Consistent with our view that details in relation to implementation are lacking we can see a number of improvements by simple additions to the requirements. These include:

- In relation to Rule 5.6, standing methodologies for generic assessment of reliability of non-network options should be required. The methodologies should be required to be developed using normal consultation processes. The network owners would be obliged to develop the proposals, but organisations such as TEC would have a formal opportunity to shape the form of the assessment and it would be a breach of the Rules to not give adequate consideration to submissions. Factors such as notice and advertising periods and the nature of information to be provided should be included either in the Rule itself or in the methodology and would apply to all technologies providing non-network solutions.

- At relevant points, Rule 5.6 could require NSPs to include, in their annual planning statements and in their considerations of particular augmentations, statements about how the reliability of non-network options for each situation is to be accounted for. This would necessitate statements about the level of plant performance assumed by the NSP.

The Rules limit some of these requirements to transmission and a further amendment should be to require the information about planning and methodology obligations to also apply to distribution.

These simple amendments will require network owners to state how they will deliver on the principles already embedded in the Rules, and will establish the basis on which they will be held accountable for following the procedures.

4.2.7. Network Pricing

The structure of pricing arrangements is a significant barrier to distributed generation, especially for smaller units within the distribution system. These units are caught by the impact of averaging of costs across groups of customers and locations within the network that is common within distribution tariffs. Advances in metering technology and pricing policy are progressively improving this situation. Isolated propositions to amend arrangements related to pricing are fraught with problems as pricing is best considered as a coordinated package. As a result we hesitate to suggest a specific Rule change to “fix” pricing.

Distributed generation offers the potential for efficiency gains in two ways. Mass-market installation of micro generation, generally based on inverter technology, will reduce throughput on networks, but depending on the technology may in fact degrade load factor (as in the case of photovoltaics) and thus lead to an increase in capacity charges. This would have two effects. The first is that the economic case for other technologies that could counter the peak would be strengthened, providing appropriate price signals were present. The second is that a combination of technologies may be more efficient. Other types of distributed generation have a localised effect, which can be recognised through more location-specific tariffs or case-by-case contracting with networks. By far the simplest way to achieve this is provision for case-specific pricing or contracting, and this is already established through arrangements for non-network solutions to ensure networks meet performance standards for reliability. Accordingly, while we consider tariff design to be highly relevant in the longer term, it is a very difficult area and regulators will likely continue to struggle with how to set the balance between costs and efficiency. On the other hand, as site-specific pricing and contracting become more readily available and achievable, tariffs become less significant. In practice, both tariff redesign and site-specific non-network alternatives should be pursued, but as will be apparent, we consider the latter to offer the greater benefit.

5. SUMMARY AND CONCLUSIONS

Two general points should be kept in mind with regard to whether Rule changes are needed to effectively encourage the use of demand response (DR) and distributed generation (DG) in the NEM:

1. Because regulation of the DNSPs is scheduled to transfer from the jurisdictional regulators to the AER, it is unlikely that the jurisdictional regulators are going to put a great deal of time or energy into reforming their regulatory positions, their Codes of Practice, or licence requirements. At the same time, the AER will have a very big job on its hands when the responsibility is handed over to them in rationalising and harmonising the myriad details of the regulatory frameworks, codes and licences of the individual jurisdictions. From these observations flows the following recommendation: TEC should focus its efforts on the specific issues that the AER will need to address after it takes over the responsibility for regulating the DNSPs. There is little to be gained by engaging the jurisdictional regulators.

2. As will be evident below, our view is that the Rules already provide sufficient direction to make it clear that non-network solutions should be pursued. We do not believe that much more can be done with the Rules in this regard. It is clear, however, that very little implementation of non-network solutions is being undertaken. The challenge, therefore, is to get the intent of the Rules acted upon. In this regard, we believe that TEC and others should focus on whether the current level of implementation suggests that compliance with the existing Codes and intent of the Rules is lacking. This could entail monitoring the degree to which the assessment of non-network alternatives is being undertaken by the DNSPs and engaging in dialogue with the AER about this, and about alternative means for encouraging or enforcing compliance.

In particular, it is our view that a Rule change is not needed to ensure that DR is implemented by network businesses whenever it is found to be cost-effective. Rather, as stated above, the focus should be on removing barriers and getting the networks to more consistently and more proactively pursue non-network alternatives.

The Rules and various jurisdictional Codes already require networks (both transmission and distribution) to consider alternatives to network augmentation when such alternatives can provide services that meet relevant requirements at lower cost. Our view is that this requirement is about as far as the Rules can or should go in this regard. Several things are needed, however, to make the relevant Rules and Codes effective, including (a) proper financial cover for non-network investment (including provision of a transitional period during which networks are allowed to recover costs in the event that the selected non-network solution proves inadequate in magnitude or timing), (b) explicit acknowledgement of the potential use and value of non-network solutions in covering relatively modest amounts of load or hours at risk in order to ensure that investment in non-network solutions is considered and can be recovered in these applications, and perhaps (c) some means of checking/ensuring that the network has not ignored such alternatives.

The “proper” financial cover referred to above must include return of and return on capital (including recognition of the opex/capex trade-off that non-network solutions often entail and the implications of this for network revenue), and treatment of risk (including prudency). Our view is that addressing these issues would be more effective than a Rule change, and that were a Rule change undertaken without addressing these issues, it would be ineffective.

Further, as stated above, it may also be worthwhile to try to document whether and the extent to which the DNSPs are proactively pursuing non-network alternatives. This could take the form of monitoring the rate at which the various DNSPs are issuing calls for non-network solutions, and the degree to which they actually achieve their objectives through non-network solutions.

Where the provisions of the Rules appear adequate but there is still dissatisfaction with the outcome, there are mechanisms within the NE Rules and the National Electricity Law (NEL) for raising a dispute (see cl 8.2) and, where appropriate, for the AER to enforce the NE Rules (see Parts 3 and 6 of the NEL), and thus test the implementation by parties with obligations.

The NER is fairly direct about the obligations of NSPs to consider non-network solutions. An objective approach to monitoring and enforcement that pushes for an explicit demonstration that the requirements to consider non-network solutions have been considered could be a very useful option. Under the NER (cl 8.7.1) the AER must determine whether Registered Participants and NEMMCO are complying with the Rules and the NEL (cl 15 and various provisions within Division 6) gives it an obligation to pursue the matter if it thinks there is a case.

It is also important to note that if the AER[15] has no reason to believe any particular Rules are not being complied with, then it is not reasonable to expect that it will necessarily discover a problem. It may also be that there is a difference of view about whether a distributor has given adequate consideration to non-network solutions. An objective monitoring and enforcement regime could provide a means for testing the strength of the case that non-network solutions are not being considered as required by the NER. If the AER cannot be convinced there is a problem (or possibly even that there is a case for investigation) then it would point to either unrealistic expectations on the part of

15 The AER is responsible for enforcement and is also the manager of the dispute process. The AER website provides information on the organisation’s role in these matters and the process to be followed by stakeholders wishing to bring an issue regarding the Rules, or an alleged breach of the Rules, to its attention. The AEMC website provides information on the process to be followed in proposing a change to the Rules.

proponents or that there is a more pervasive deficiency in the Rules that can only be changed by policy, and this would require that the change satisfy the market objective.

APPENDIX A: SPECIFIC RULE CHANGE RECOMMENDATIONS

Rule changes have been recommended in several areas. The sections below provide additional information on the specific changes to be sought and the justification for those changes.

A.1 NER CLAUSE 5.6

This clause concerns standing methodologies for generic assessment of the reliability of non-network options, including notice, advertising periods, nature of the information and performance and plant performance.

- Amend appropriate points within cl 5.6.2 to require each DNSP to develop the standing methodologies it proposes to use to assess the contribution of typical non-network options to the reliability of supply to connection points.

- Market objective rationale: This amendment will enhance the market objective by lowering a barrier to entry, and will increase efficiency by providing increased certainty and rigour about how the DNSP will assess an embedded generation proposal and thus allow proponents to focus on proposals more likely to succeed.

- Amend cl 5.2.5 to require DNSPs to prepare and publish details of the content and format of technical requirements expected to be provided by a generator.

- Market objective rationale: This amendment will enhance the market objective by making the process of applying for connection more efficient by ensuring the applicant is aware of all the information it is required to provide at an early stage.

A.2 NER CLAUSE 5.6.2(M)(2)

This clause, as amended, would require contracts to be formed that would allow an embedded generator to maximise the potential revenue it could raise beyond only network support services.

- Amend the clause to ensure that the fact that a generator has entered into a contract for network support will not prevent that generator from participating in other markets or services operated by network service providers or NEMMCO.

- Market objective rationale: This amendment will enhance the market objective by lowering a barrier to entry by ensuring contracting for network support does not inadvertently inhibit proposals that provide overall benefits to the market that are spread across a number of services.

A.3 NER CLAUSE 5.3.6

This clause, as amended, would put the responsibility for establishing suitable technical connection requirements on the NSP instead of the DG proponent.

- Amend to make it the responsibility of (a) the NSP to develop one or more sets of interconnection requirements, where different sets would apply to different classes or configurations of interconnection proposals, and (b) the jurisdictional regulator (or AER after such time as it assumes these responsibilities) to review these connection requirements to ensure that the necessity of each specific requirement is justified and that the requirement as a whole represents the most cost-effective means for achieving the objective of the requirement.

- Market objective rationale: This amendment will enhance the market objective by lowering a barrier to entry by ensuring that connection requirements are cost-effective and justified, and do not pose an undue technical or financial hurdle to proposals that can provide benefits to the market.