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19 June 2008

Dr John Tamblyn
Chairman
Australian Energy Market Commission
Level 5
201 Elizabeth Street
SYDNEY NSW 2000

Dear Dr Tamblyn

Review of the Role of Demand Side Participation in the NEM: Stage 2 – Issues Paper

Ergon Energy Corporation Limited (Ergon Energy) appreciates the opportunity to comment on the Australian Energy Market Commission's (AEMC) Issues Paper relating to Stage 2 of the AEMC's review of Demand Side Participation in the National Electricity Market. The attached submission is provided by Ergon Energy in its capacity as an electricity distribution network service provider in Queensland.

Ergon Energy is available to discuss this submission or provide further detail regarding the issues that it has raised should the AEMC require.

Yours sincerely

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Ergon Energy Corporation Limited

Stage 2: Review of Demand Side Participation in the National Electricity Market – Submission

Australian Energy Market Commission

20 June 2008

Stage 2: Review of Demand Side Participation in the National Electricity Market

Submission

Australian Energy Market Commission

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This submission, which is available for publication, is made by:

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TABLE OF CONTENTS

1 Overview

Ergon Energy Corporation Limited (Ergon Energy) appreciates the opportunity to comment on the Australian Energy Market Commission's (AEMC) Issues Paper relating to Stage 2 of the AEMC's review of demand side participation (DSP) in the National Electricity Market (NEM). This submission is provided by Ergon Energy in its capacity as an electricity distribution network service provider (DNSP) in Queensland.

Ergon Energy is available to discuss this submission or provide further detail regarding the issues that it has raised should the AEMC require.

As a general comment, Ergon Energy strongly supports the development of a regulatory regime which provides for the efficient investment in, and efficient use, of distribution services. This may be facilitated through a combination of:

- Incentives for network service providers to pursue the most efficient options to deliver against their regulatory requirements, including demand management or the procurement of DSP where appropriate; and

- The removal or reduction of barriers inhibiting efficient demand management and DSP.

'DSP' for the purposes of the AEMC's review, has been defined as:[1]

> *...the ability of consumers to make decisions regarding the quantity and timing of their energy consumption which reflects their value of the supply and delivery of electricity.*

Ergon Energy notes that the Issues Paper focuses on an examination of the National Electricity Rules (Rules) to determine where there may be obstacles to efficient DSP in the NEM, including the Rules as they pertain to DNSPs. The role of DNSPs in the NEM is important in this context. In particular:

- DNSPs facilitate the physical delivery of electricity between generators and customers;

- DNSPs do not dictate or control the amount of electricity generated or consumed;

- DNSPs have no direct influence over the wholesale price of energy and only charge customers for moving it through their networks; and

- DNSPs are not Market Participants under the Rules – they are neither 'bidders' nor 'takers' in the NEM.

Ergon Energy believes that, by focusing the Issues Paper on the Rules as they apply to DNSPs, there is insufficient focus on those aspects of the Rules which are capable of influencing customer choice regarding the quantity and timing of consumption.

[1] AEMC, *Review of Demand side Participation (DSP) in the NEM – Terms of Reference*, page 1.

Ergon Energy believes that the AEMC should clearly distinguish between initiatives or regulatory changes which influence the ability of consumers to make decisions regarding their consumption (i.e. DSP) and the pursuit of demand management more broadly (e.g. industry-driven demand management initiatives which may or may not be supported through incentives under the regulatory framework):

- This distinction is particularly important given the Australian Energy Regulator's (AER) concurrent investigation of the detailed guidelines, model and schemes that will support the economic regulation of DNSPs under the new Chapter 6 of the Rules. This framework has yet to be finalised let alone tested and should be permitted to 'bed-down' before additional change is contemplated or imposed on participants. Only once this has occurred will it be possible to comment on the effectiveness of Chapter 6 of the Rules in delivering incentives to facilitate an appropriate level of DSP in the NEM.

  Recommendations for further change at this point in time would be of major concern to the DNSPs in Queensland and South Australia who are already in the process of preparing their regulatory proposals for the next regulatory control period.

- The AEMC's review is occurring at a time when a number of other reviews, with the potential to directly impact the framework for DSP in the NEM, are partly completed. These reviews include the:

  - AER's ongoing development of the electricity distribution guidelines, models and schemes to support the operation of Chapter 6 of the Rules;
  - AER's current consideration of the potential introduction of a Demand Management Incentive Scheme (DMIS) for the electricity distributors in Queensland and South Australia;
  - Ministerial Council on Energy's (MCE) current work program and cost benefit analysis for Smart Meters;
  - MCE's ongoing review of Network Incentives for Distributed Generation and Demand Side Response;
  - MCE's ongoing review of Network Planning and Connection Arrangements;
  - MCE's ongoing development of a National Framework for the Non-economic Distribution and Retail Regulation; and
  - AEMC's final report to the MCE on the Congestion Management Review.

  Until these reviews and their recommendations are taken into consideration, it is difficult to see how the AEMC can effectively establish a 'base case' against which its options for amendment can be assessed.

- Furthermore, the AEMC's review is occurring at a time of significant policy development in the area of climate change (e.g. Emissions Trading Scheme, Mandatory Renewable Energy Target and state-based schemes to encourage increased energy efficiency at all customer levels). These policy initiatives are likely to have a significant impact on the NEM's operation and participant behaviours. The impact of these policy changes has been recognised by the MCE through its decision to instruct the AEMC to "conduct a review of the energy market frameworks to determine whether the frameworks need to be amended to accommodate the introduction of emissions trading and the renewable energy target".[2]

Therefore, when undertaking the review the AEMC should:

- *Explicitly acknowledge concurrent reviews and areas of policy development by the MCE and market institutions* – the AEMC should only seek to address those matters which are not already under consideration in another forum – i.e. duplication in the subject matter of the reviews should be expressly avoided; and

- In this context, determine:

    - *The nature of the DSP 'problem' that is sought to be resolved* – i.e. the factors impeding decision-making by consumers as to the quantity and timing of their energy consumption. The Issues Paper is unclear in this regard; and

    - *The range of measures that may be available to address the DSP problem identified* – i.e. what elements of the NEM could be modified to assist consumers in decision-making regarding their consumption. A number of the options considered in the Issues Paper respond to perceived failings in the integration of demand management into the NEM or the framework for economic regulation, rather than the facilitation of DSP.

[2] MCE, *15th Meeting Communiqué*, 13 June 2008.

2 Economic Regulation of Networks

As noted in section 1, the revised framework for the economic regulation of DNSPs under Chapter 6 of the Rules is as yet untested and should be permitted to 'bed-down' before additional change is contemplated or imposed on participants. Only once this has occurred will it be possible to comment on the framework's effectiveness in delivering incentives to facilitate an appropriate level of DSP in the NEM.

2.1: Potential Barrier – the balance of incentives may not encourage the efficient inclusion of demand side options.

Q – What are the impacts that the service incentive targets and the associated incentive scheme may have on the incentives for the use of efficient DSP?

Q – Does the regime, through the use of incentives such as the ECM, encourage network businesses to avoid operational expenditure that would be spent on DSP?

The schemes under Chapter 6 of the Rules only form one part of a broader economic regulatory framework that is encouraging DNSPs to pursue the most efficient means of meeting network demand and customer needs. Importantly, the schemes:

- Are not substitutes for the funding required by DNSPs to efficiently operate their networks (i.e. their allowable capital and operating expenditure); and

- In general, are structured as penalty and reward mechanisms which respond to the way in which DNSPs apply the Rules and operate.

In developing a scheme, clause 6.5.8(c)(5) of the Rules requires the AER to have regard to "the possible effects of the scheme on incentives for the implementation of non-network alternatives". Further to this:

- The Service Target Performance Incentive Scheme (STPIS) establishes a series of target performance values for a number of service parameters, against which a DNSP may be rewarded or penalised. The STPIS is to be distinguished from minimum service standards imposed under state-based arrangements which represent the minimum performance standards that a DNSP must achieve, but to which no direct financial reward or penalty is attached for achieving, exceeding or failing to meet the standard. Relevantly, the STPIS is not in itself intended as a mechanism for encouraging DSP. Indeed, DSP initiatives may be classified under a category of services that is not subject to the STPIS.

  Ergon Energy notes that the AER has proposed a mechanism for modifying the allowed performance targets under the STPIS in circumstances where a non-network alternative is expected to materially influence network reliability performance – i.e. to ensure that the measurement of a DNSP's service performance under the STPIS does not create a preference for network alternatives.[3] Ergon Energy believes that this permits appropriate recognition of the relative incentives to undertake network and non-network alternatives for those initiatives that do appropriately fall within the ambit of the services covered by the scheme, and that no other mechanisms are required in this regard.

[3] AER, *Proposed: Electricity distribution network service providers - Service target performance incentive scheme* (April 2008), at clause 3.2.1.

- The Efficiency Benefit Sharing Scheme (EBSS) is designed to provide an incentive for the DNSP to reveal its efficient levels of expenditure through the retention of efficiency gains for a period of time and to calculate the revenue increments or decrements that provide a fair sharing of efficiency gains and losses between DNSPs and customers. As with the STPIS, it is not in itself intended as a mechanism for encouraging DSP.

  It is noted that:

  - The proposed EBSS expressly excludes the costs of non-network alternatives. Ergon Energy supports this as a means of ensuring that disincentives to undertake non-network alternatives are not introduced by virtue of the EBSS; and

  - Clause 6.5.8(b) of the Rules provides that the EBSS may (but is not required to) cover efficiency gains and losses relating to capital expenditure. Ergon Energy believes that this provides the AER with adequate flexibility to extend operation of the EBSS to capital expenditure in the future if a bias towards capital expenditure is found to exist. The AER should not however be involved in operational decisions of DNSPs regarding operating and capital expenditure trade-offs.

Given that the STPIS and EBSS are as yet untested and in light of the AER's express recognition of the impact on non-network alternatives in the schemes' development, a failure in the operation of a scheme should be demonstrated prior to any recommended change. That is, whether in practice, expenditure (including that which is non-network) is being inappropriately allocated or deferred.

2.2: Potential Barrier – the building blocks form of regulation may limit the incentives for innovation on demand side participation.

Q – Do the Rules provide sufficient incentives for network business to undertake research and development and innovation on DSP initiatives?

Q – What approaches could be adopted to encourage efficient innovation on DSP?

Ergon Energy supports the provision of incentives for a DNSP to undertake research, development and innovation and believes that all expenditure incurred by a DNSP that is associated with demand management or DSP (including network support payments, marketing costs, contracts establishment, etc) should be recognised in the relevant control mechanism for its prevailing form of regulation (i.e. in the building blocks).

It should be recognised however that demand management and demand side trials and programs in many jurisdictions are in the early stages of development. The regulatory framework therefore should allow for the continued development by DNSPs of demand management and DSP experience and capability, such as through a DMIS and be flexible enough to recognise these jurisdictional differences, account for existing demand management and DSP programs, and permit future development and innovation by DNSPs.

For its own operations, Ergon Energy supports the following framework for the next regulatory control period (i.e. from 1 July 2010):

- Ergon Energy would implement a series of demand management projects and initiatives. These demand management projects and initiatives will be aimed at building Ergon Energy's demand management experiences and capability (i.e. "learn and do" for demand management products, technologies and capabilities);

- The demand management projects and initiatives would be:

  - Included in Ergon Energy's Regulatory Proposal;

  - Funded through quarantined operating and capital expenditure (as appropriate); and

  - Approved by the AER on an ex ante basis as part of Ergon Energy's building block proposal;

- The operating expenditure allowance under the DMIS should be explicitly quarantined from the operating expenditure calculation applied under the EBSS; and

- Ergon Energy would be subject to the AER's national DMIS from the following regulatory control period (i.e. from 1 July 2015).

2.3: Potential Barrier - the form of price control may not facilitate efficient demand side participation.
Q – Based on price caps and revenue caps having different incentive properties, what is the materiality of the impact of these incentives on the pursuit of efficient DSP options while having regard to the positive outcomes each form of price control may encourage?

The relative incentives and disincentives for each DNSP to conduct demand management or facilitate DSP will need to be assessed in the context of the specific control mechanisms and service classifications that will apply to that DNSP.

Ergon Energy believes that there are sufficient tools within the Rules to permit the AER to provide the required incentives (or redress any bias) through arrangements which are tailored to each individual DNSP's circumstances and form of price control.

2.4: Potential Barrier - the structure and components of tariffs may not provide customers with efficient signals about electricity use.
Q – Would there be benefits from increasing the locational components of tariffs or requiring more efficient signals about the use of network capacity to be provided to consumers?

Ergon Energy believes that the Rules should only provide high level pricing objectives that must be applied by the AER when assessing DNSPs' pricing proposals. That is, there should be no mandated requirement about operational pricing matters.

If it is assumed that a high-level pricing objective is to encourage customer response and changes in behaviour through the delivery of price signals, an efficient pricing structure would ideally reward customers for appropriate behaviour / actions and penalise customers for unwanted behaviour / actions.

Although Ergon Energy fully supports the development by DNSPs of efficient pricing structures, the ability to communicate locational price signals to customers may be limited as a consequence of Government policy or the inability of retailers to pass these costs through to customers (whether as a consequence of regulatory constraints, competitive pressures or simply as a consequence of tariff 'bundling').

By way of illustration, in Ergon Energy's distribution area:

- Only a small number of Ergon Energy's distribution customers (typically large contestable customers) see their actual network charges. The vast majority of Ergon Energy's customers are on Government regulated notified prices – these do not separate the tariff payable by the customer into network and retail components (i.e. the notified prices are 'bundled');

- Queensland's uniform tariff policy means that the delivered cost of energy for a large percentage of Ergon Energy non-market customers is subsidised by the Queensland Government through a Community Service Obligation paid to Ergon Energy Queensland Pty Ltd (the Local Retailer). This subsidy is not explicitly identified to individual customers. Therefore, even if the notified prices were unbundled, the majority of non-market customers in Ergon Energy's distribution area would not see a cost reflective price; and

- Side constraints have traditionally been imposed on increases in distribution prices for individual customers or customer classes, to limit price shocks.

Policies and technology limitations may therefore limit the ability for customers to receive and respond to the price signals that are communicated through a DNSP's pricing structure.

3 Network Planning

As an overarching comment, Ergon Energy does not support any modification of the Regulatory Test as it applies to distribution as part of the current review process. This would be consistent with the position adopted in the AEMC's Draft Report on national transmission planning arrangements:[4]

> *The Regulatory Investment Test for Distribution will be the current regulatory test. The MCE is currently finalising its review on distribution and retail regulation and the appropriate project assessment framework for distribution projects should be considered through the process of developing the new Rules for distribution, rather than as part of this Review.*

Issues regarding the consultation processes to be applied by DNSPs should not be considered in isolation from a broader assessment of the policy objective that is sought to be achieved through the application of the Regulatory Test to DNSPs, including whether the existing framework for distribution is effective in achieving this objective.

A holistic review of the Regulatory Test as it applies to DNSPs is therefore required. The current process is not the appropriate forum for this review to occur.

3.1: Potential Barrier – the Regulatory Test threshold may be limiting the ability for alternatives to smaller network augmentations to be considered.
Q – Do the consultation requirements for new small and large network assets provide sufficient opportunity for non-network options to be revealed in the planning process?

In drawing parallels between the regulatory arrangements that apply to transmission and distribution, the AEMC should note that DNSPs undertake a significantly higher number of small distribution augmentations compared to transmission network service providers (TNSPs). As a consequence, a requirement for DNSPs to publicly consult on both new small network assets and new large network assets would:

- Impose a material administrative and cost burden on DNSPs that does not appear justified in terms of the response that has been received to date on those augmentation proposals which have proceeded to public consultation under the Regulatory Test (refer to section 3.2); and

- Adversely impact the time taken to complete projects given the high volume of new small network augmentations that are undertaken. This is an issue of particular impact for Ergon Energy given the geographic spread of its distribution area and high growth on its network.

Ergon Energy is of the view that:

- The current processes for consultation under the Regulatory Test generally provide an adequate opportunity for interested third parties to propose options, including non-network, to meet identified network limitations; and

[4] AEMC, *National Transmission Planning Arrangements – Draft Report* (2 May 2008), at page 32.

- It has not been demonstrated that the existing threshold for public consultation under the Regulatory Test has acted to limit the uptake of non-network solutions. In this context, Ergon Energy draws attention to the fact that the monetary thresholds in the Rules have not been escalated as they apply to DNSPs since the inception of the Regulatory Test - this is despite clear recognition by all parties, including the regulators, that network service provider costs have escalated over time. It is acknowledged that the AEMC is currently considering a Rule change proposal to increase the monetary thresholds as they apply to TNSPs.

Ergon Energy does accept the need for transparency in its planning and network expansion arrangements and would support a requirement for DNSPs to undertake and publish annual planning reports which include information that can be reasonably provided and is of real and measurable benefit to the market. It is envisaged that this would be of a similar nature to the annual Network Management Plan (NMP) that Ergon Energy is required to publish under clause 2.3 of the Queensland Electricity Industry Code.

Annual planning reports should:

- Be limited to the sub-transmission level and above to ensure that specific projects can be detailed, rather than the high volume of smaller projects that occur at distribution voltages and below;
- Contain information that can be provided with reasonable certainty and accuracy;
- Provide meaningful data to the audience, including proponents of non-network solutions;
- Not expose DNSPs to liability from persons seeking to rely on the information; and
- Balance the cost (and resource) burden on DNSPs to compile the report and the likely benefit to the market from its publication.

These reports could be published in a central location (e.g. the NEMMCO website) to facilitate access by prospective proponents of non-network solutions.

The publication of annual planning reports would be preferable to the significant impost associated with either a lowering of the monetary thresholds for the Regulatory Test or requiring DNSPs to publicly consult on both new small network assets and new large network assets.

3.2: Potential Barrier – the planning arrangements may not allow sufficient time for demand side options to integrate in the planning process.

Q – Do the arrangements in Chapter 5 of the Rules provide potential demand side proponents with sufficient time to develop alternative proposals when options are being sought?

Q – What are your views on the nature and extent of any inconsistencies in jurisdictional planning requirements and which jurisdictional arrangements most effectively reveal efficient demand side options in response to a proposed network investment?

Ergon Energy believes that the arrangements in Chapter 5 of the Rules provide potential demand side proponents with adequate time to develop alternative proposals when options are being sought.

The consultation processes applied by DNSPs under the Regulatory Test ensure that necessary information regarding emerging network constraints is provided to potential proponents at an early stage of the development process. In Ergon Energy's case, this includes:

- Providing information about the existing distribution network in the impacted area;
- Providing information about emerging distribution network limitations and the expected time by which action must be taken to maintain the reliability of the distribution system;
- Providing information about the criteria (technical and non-technical) that must be satisfied; and
- Explaining the process (including approach and assumptions) to be used to evaluate alternative solutions, including distribution options.

In addition to the existing consultation processes prescribed under the Regulatory Test, Ergon Energy:

- Issues Requests for Information (RFIs). Although not a requirement under the Regulatory Test as it applies to distribution, Ergon Energy voluntarily issues RFIs for all new large distribution assets as an input into its economic cost effectiveness analysis of possible options under clause 5.6.2(g) of the Rules and subsequent consultation on this aspect of the Regulatory Test process.
- Produces an annual NMP which details the nature and timing of identified constraints and associated projects over a five year horizon, including:
  - network capacity information and load forecasts;
  - network limitations;
  - augmentation works scheduled to undergo the Regulatory Test or other public consultation;
  - analysis, options and potential projects;
  - opportunities for non-network solutions; and
  - a summary of priority projects.

  One of the functions of the NMP is to facilitate stakeholder feedback on network constraints, supply issues and proposed solutions, and thereby provide awareness of potential investment opportunities which may be cost effective in avoiding or postponing network expansion.

It should be noted that, despite the planning information that is currently provided to the market, Ergon Energy has to date not received any formal proposals in relation to an identified network constraint, although it has received one informal proposal that did not ultimately proceed.

When considering the level of disclosure that should be mandated and its timing, it is important that both the size / expected value of the project and the level of anticipated response are weighed against the transaction costs that will be incurred by the DNSP, and ultimately paid for by consumers.

As noted above, the publication of annual planning reports by DNSPs, spanning an appropriate time horizon, and the timely commencement of consultation on constraints where appropriate, would assist in providing 'advance notice' of emerging network limitations and thereby provide proponents of non-network alternatives with a reasonable opportunity to develop a proposal and commence discussions with the relevant DNSP.

3.3: Potential Barrier – consultation on augmentation options rather than on the needs of the network may create bias against demand side options.

Q – Do the current planning arrangements encourage an undue emphasis on network options to the disadvantage of efficient DSP options? If so, please identify the causes of any under-consideration of non-network options and measure that might be adopted to improve the efficiency and balance of the planning process?

Q – Are there any lessons from the NTP review that could be applied to distribution networks in this context?

Ergon Energy does not believe that the current planning arrangements unduly emphasise network options over non-network options.

Ergon Energy's public consultation processes do not pre-suppose a particular solution or constrain the range of non-network alternatives that may be raised for consideration by project proponents. For example, the RFI establishes a series of broad criteria to assist solution providers to understand the technical (e.g. those contained in Schedule 5.1 of the Rules) and other requirements that must be satisfied if a non-network solution is to compensate or rectify emerging technical limitations in the distribution network.

In this context, it is important to recognise that a non-network solution, whether it is the implementation of local generation or DSP, may only reduce or delay the need for new network investment – it will not, in all instances, remove the need for augmentation to occur. Flexibility is therefore required throughout the public consultation process to enable the investigation of options or combinations of options that represent the most efficient response to the identified need – e.g. a hybrid response that allows for an overall lower economic cost, or optimisation of a customer's load as part of the connection planning process. It is for this reason that an alternative and more structured process, such as a tender, would unnecessarily constrain DNSPs, proponents and customers in the development of viable and timely solutions.

4 Network Access and Connection Arrangements

Ergon Energy notes that pricing, access and connection arrangements for embedded generators (EGs) have been the subject of significant consultation by the MCE throughout 2006 and 2007, including:

- The Renewable and Distribution Generation Working Group's review of policy directions for removing impediments to, and promoting the commercial uptake of renewable and distributed generation technologies and practices; and

- The Energy Market Reform Working Group's review of the network incentives under the regulatory arrangements for networks and impacts for non-network alternatives such as distributed generation and demand side response.

Ergon Energy understands that, following consideration of the recommendations contained in the independent reports that were commissioned by the MCE and submissions received through the process of public consultation:

- A series of amendments to the framework for distribution revenue and pricing were included as part of the MCE's economic legislative package and are now reflected in the revised Chapter 6 of the Rules;[5] and

- Recommendations or outstanding issues which are relevant to network planning and connection are under consideration for possible inclusion in the non-economic regulation package for distribution.[6]

Given the MCE's recent and ongoing consideration of these issues and the amendments to the Rules in response, Ergon Energy queries whether the scope of the issues proposed for consideration by the AEMC is appropriate.

Ergon Energy believes that any issues which duplicate matters addressed or under consideration by the MCE should be removed from the scope of the current review.

4.1: Potential Barrier – arrangements for avoided TUOS and DUOS may under/over value demand management options.

Q – Do the existing requirements for avoided TUOS and DUOS in the Rules provide efficient incentives for investment in an location of EG and whether the current rebate arrangements reflect appropriately the network benefits provided by EG? Can the efficiency of these arrangements be improved?

Ergon Energy supports a framework for connection charges which provides a locational price signal to large loads and EGs, and which includes 'dedicated assets', 'extension assets' and attributable costs of augmenting the shared network. Ergon Energy believes that, for this framework to be efficient, both the benefits and costs of large loads and EGs to the network should be recognised (e.g. liability associated with performance failures).

[5] NERA, *Part One: Distribution Rules Review – Network Incentives for Demand Side Response and Distributed Generation* (April 2007) and SCO, *Response to Stakeholder Comments on the Exposure Draft of the National Electricity Rules for Distribution Revenue and Pricing (Chapter 6)* (August 2007).

[6] NERA/ACG, *Network Planning and Connection Arrangements – National Frameworks for Distribution Networks* (August 2007) and MCE, Energy Market Reform Bulletin No 99 – National Frameworks for Distribution Networks: Network Planning and Connection Arrangements (August 2007).

Ergon Energy notes that the AEMC's Congestion Management Review (commissioned by the MCE) has recommended a series of measures to improve the levels of information available on congestion points. This information will assist market participants and DSP proponents in understanding congestion, whether that congestion is enduring, and the optimal locations for investment.

4.2: Potential Barrier – minimum technical standards for connection to the network may provide a barrier to potential embedded generation options.

Q – Do the existing technical standards contained in the Schedules of Chapter 5 of the Rules reflect the minimum requirements for connection?

Q – Are the minimum standards for connection consistent across jurisdictions and reflect appropriate minimum requirements for connection of EG to the network?

Ergon Energy supports, in principle, a common framework for the connection of EGs. A distinction however needs to be drawn between the arrangements that apply to micro EGs (e.g. solar PV primarily for a customer's own use) versus other (i.e. larger commercial) forms of EG:

- For micro EGs, Ergon Energy supports the development by a DNSP of a 'standard' contract and a standard network consent agreement which addresses technical specifications and ongoing operational interactions. This documentation would be approved by the AER; and

- For other EGs, Ergon Energy believes that the framework of 'automatic', 'minimum' and 'negotiated' access standards provided for in Chapter 5 of the Rules allows the necessary flexibility to account for the EG's and DNSP's specific technical and operational circumstances, while maintaining system security and reliability. DNSPs (individually and collectively) will pursue standardisation where practical, to assist in alleviating the administrative burden for both parties. It is noted that the Energy Networks Association has acknowledged the issue of national consistency and has initiated work on an issues paper which is expected to be finalised in late 2008.

4.3: Potential Barrier – deep connection costs to the network may be a barrier to potential embedded generation options.

Q – What is an appropriate framework to ensure consistency regarding the connections costs of EGs?

Q – Noting the different treatment of connections costs across jurisdictions, is there a framework that would better facilitate the efficient connection of EGs?

The Issues Paper raises the potential for consistency between the arrangements that apply to transmission and distribution (i.e. to permit the recovery of shallow connection costs only). Ergon Energy does not support this approach and notes that differences in the nature of distribution and transmission networks means consistency in this instance is not justified.

Ergon Energy supports a framework that is consistent between large customer loads and generation in that:

- There is recognition of the impact of new connections on upstream shared network assets. This is because every new connection has some impact on the shared network and to the extent that a new customer or EG's impact is uneconomical (i.e. is above the average cost being funded by existing customers), then there should be an accompanying price signal; and

- A DNSP is allowed to recover:

  - all the cost if the shared network works are outside the DNSP's planning horizon; or

  - the cost of advancing these works if the shared network works are within the planning horizon,

  in circumstances where a connection (for load or generation) triggers an identifiable requirement for a DNSP to carry out works on the shared network.

Recognising the differences that exist between jurisdictions in the treatment of connection costs, the policy implications of any change to the existing regime need to be fully understood, including consideration of transitional arrangements that may be required to manage a shift from existing practices.

4.4: Potential Barrier – contracting arrangements for embedded generation may not reflect the network support benefits that can be provided.
Q – what is the extent to which EGs are able to negotiate their contractual arrangements in a timely manner, with sufficient information, such that the remuneration they receive is an appropriate reflection of the network support benefits they are providing?
Q – Are the dispute resolution arrangements adequate in this area? And is there any benefit in clarifying dispute resolution provisions in the Rules?
Q – Is the treatment of the benefits that aggregators provide as a package of network benefits appropriate?

As noted above, Ergon Energy supports, in principle, a common framework for the connection of EGs. A distinction needs to be drawn however between the requirements that apply in the pre-connection phase versus the connection phase.

Pre-connection

The pre-connection phase refers to those circumstances where the EG does not have an existing connection to the network and the DNSP has to undertake information exchange and works to provide a physical connection.

Ergon Energy supports a requirement in the Rules for a:

- 'Non-Standard' contract or letter of offer for pre-connection for micro EG to be developed by DNSPs and approved by the AER. The non-price terms in the pre-connection letter will necessarily be highly dependent upon each customer's physical location and circumstances but not subject to negotiation. Negotiation on price will depend on whether the services are classified as Direct Control Services or Negotiated Services; and

- For all other (usually larger) loads and generation, the pre-connection process may or may not include a negotiation on technical and operational matters, and co-ordination of the parties during the construction phase. Negotiation on price will depend on whether the services are classified as Direct Control Services or Negotiated Services.

The price for services that are Direct Control Services will be regulated and not subject to negotiation. In this key respect, the process will differ form the Negotiation Framework provisions in Chapter 6 of the Rules.

Connection

The connection phase refers to those circumstances where there is an existing physical connection to the network, or the pre-connection works have been completed, and the EG is seeking access to the network.

Ergon Energy supports a requirement in the Rules for a:

- 'Standard' contract and a standard network consent agreement for micro EG. A 'negotiation' process should not be applied to connection services for micro EGs as it would be:
    - unworkable in practice given the large number of connections undertaken each year; and
    - unnecessary given the standardised nature of services and the previous recommendation that the application form and contract for these services would be subject to approval by the AER; and
- A 'non-standard' contract for other (usually larger) generation which recognises there are significant differences in technical specifications and ongoing operational interactions between large loads and generation and DNSPs. As noted above, the price for connection services that are Direct Control Services will be regulated and not subject to negotiation.

Ergon Energy supports in principle, the adoption of a standard information exchange process for establishing non-standard connections (that is, arrangements for large load and small, medium and large EGs) covering both the pre-connection and connection phase. This would include:

- A requirement for the exchange of technical, price and other non-price information. As noted above, the price for connection services that are Direct Control Services will be regulated and not subject to negotiation on price terms;
- A requirement for the DNSP to use reasonable endeavours to provide the user with the service it requires;
- Any offer to be consistent with the safe and reliable operation of the power system (e.g. by reference to the technical standards in the Rules); and
- A requirement for the DNSP to consult with any affected network users and NEMMCO, if the DNSP believes, in its reasonable opinion, that compliance with the terms and conditions of those connection agreements will be affected.

5 Wholesale Markets and Financial Contracting

5.1: Potential Barrier – wholesale market processes may exclude potential demand side resources from efficiently participating.
Q – Can more flexibility be provided in the dispatch arrangements to facilitate DSP and what would be the impact of doing so?
Q – Can the accuracy of NEMMCO's demand forecasts be improved? If so, what are the ways?

Ergon Energy understand that companies providing demand side response may require varying lead times and therefore, an inaccurate forecast may lead to an incorrect commitment decision by the DSP provider. Although this error is compensated by NEMMCO dispatched generation so that supply equals demand, the overall price outcome may be sub-optimal.

Even in circumstances where there is a demonstrated need for additional flexibility in the NEM's dispatch arrangements, it will be difficult to amend the Rules to introduce the required flexibility while preserving the integrity of the bidding and dispatch processes. Ergon Energy believes therefore that the focus should be on the improvement of short term forecasts, rather than any amendment to the bidding and dispatch arrangements.

5.2: Potential Barrier – demand side participants may not be adequately compensated for providing a demand side response.
Q – Are the costs to participate in the wholesale market too high or inappropriate for demand side proponents?
Q – Is there merit in developing mechanisms in the Rules to reduce the costs of contracting between retailers and demand side proponents?

While Ergon Energy is not opposed to the concept of a DSP bulletin board, this may in practice be a costly means of achieving the objective of bringing retailers and demand side resources together. As evidenced by previous attempts in the Australian gas market, bulletin boards can readily fail through a lack of participation.

There may be value in a central register (e.g. maintained by NEMMCO) of DSP providers, so that network service providers have a consolidated list of interested parties to whom information can readily be disseminated.

5.3 Potential Barrier – the costs of involvement in the wholesale market and in financial contracting may be unnecessarily high.
Q – What are the costs for various demand side resources to participate?
Q – Is there a need for additional uplift payments to compensate demand side resources for the benefits they may provide to the market?

Ergon Energy does not support the provision of an additional uplift payment to demand side resources. The provision of an uplift payment would be premised on the load or generator's participation in the wholesale market. Such a payment would therefore appear to be contrary to the market design principles in clause 3.1.4(a) of the Rules, in particular, the "avoidance of any special treatment in respect of different technologies used by Market Participants".

6 Reliability

6.1: Potential Barrier – the use of short-term emergency Reserve Trader may not facilitate the development and use of efficient demand side participation for reliability. *Q – Would there be benefits from increasing the certainty and reducing the costs of the arrangements through a standing reserve?*

Measures to reduce the costs of the Reserve Trader mechanism are supported in principle although alternatives must have the same guarantees of performance.

The failure of alternative measures to deliver the level of response required will result in consumers bearing higher energy costs than under the status quo.

6.2: Potential Barrier – the use of reserves may not allow demand side participants to obtain a fair market value for their services. *Q – Without the Reserve Trader, or through the use of alternative mechanisms, would the demand side be able to better participate in providing reserve to the market?* *Q – Are there any other alternatives for maintaining reliability of supply without distorting market outcomes and investment signals?*

No comment is provided.