24 June 2002

Mr. Michael Rawstron
General Manager Regulatory Affairs
Australian Competition and Consumer Commission
PO Box 1199
Dickson ACT 2602

Dear Michael,

ACCC Issues Paper- Review of the Regulatory Test

Thank you for the opportunity to comment on the ACCC's Issues Paper on the Review of the Regulatory Test. This letter constitutes a submission from the National Electricity Distributors Forum (the NEDF)[1] to the ACCC on the matter.

The NEDF is generally supportive of a streamlined, workable and uniform investment approval process for infrastructure investment instituted as a Code requirement, where it is appropriate to do so.

The NEDF's principal concern, however, is that an investment approval process instituted as a Code requirement for distribution networks will overlap and in many instances contradict existing Jurisdictional arrangements for prudent investment criteria for Distribution Network Service Providers (DNSPs).

The National Electricity Code (NEC) deals principally with the wholesale market and the interaction between market participants. This generally comprises NEMMCO, generators and retailers as well as transmission and distribution networks. The interaction of the NEC with retail markets and end use customers (only one of whom is a Code Participant and bound by the NEC) is minimal, including the interaction between distributors and customers. The customer/distributor relationship is managed by Jurisdictional regulators. It is enforced by the Jurisdictional regulatory frameworks, which assign rights and responsibilities to both distributors and customers.

Jurisdictional regulators determine distribution pricing arrangements, regulated asset values, incentive arrangements to promote efficient networks and minimum standards for the delivery of service to customers. Any coverage of these issues by the NEC needs to be conducted with the close cooperation of each jurisdiction for successful implementation. It may be that a staged approach taking several years would be required for the Jurisdictional requirements to be aligned.

The differences between the general purpose of transmission and distribution networks should be considered in these matters. Transmission generally links major generation with major load

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[1] The National Electricity Distributors Forum comprises the following member organisations: Energex; Ergon Energy Corp. Ltd; Country Energy; Australian Inland Energy; EnergyAustralia; Integral Energy; ActewAGL Distribution; AGL Electricity; CitiPower; TXU; Powercor; United Energy; ETSA Utilities; Aurora Energy; and Western Power Corporation.

centres. Transmission has very few direct customers, and these are generally Code Participants. On the other hand, Distribution generally links hundreds of thousands of customers (who are not Code Participants) with the transmission system, thereby delivering energy to end use customers.

Distribution networks need to be quickly augmented to connect a new customer. Jurisdictional arrangements generally require that the beneficiaries pay any incremental costs through network tariffs and capital contributions. The distribution system is more complex than the transmission system, and augmentations are generally more localised in impact.

The NEC may be able to identify principles that distributors and jurisdictional regulators might need to consider in determining local regulatory arrangements. These principles may be similar to those used for transmission. However, the processes used are likely to be different, given the different size, relative impact of spot loads and number of customers involved. Such principles should be limited to major distribution investments, which affect large numbers of customers.

Following the promulgation of the Regulatory test in December 1999, NECA consulted on a package of Code changes during 2000/01[2]. It proposed Code changes that would have resulted in similar Code approval processes for both transmission and distribution investment. The NEDF raises concerns in this submission to the ACCC which it raised in its submission to NECA in 2001, which led to modification of those proposed Code changes and greatly reduced the degree of overlap with Jurisdictional requirements.

However, Code obligation (Clause 5.6.2(g)) still requires DNSPs to carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test. The NEDF believes that the requirement to assess market benefits in the regulatory test for proposed distribution network augmentation is not workable. The NEDF proposes that the Code specify an investment threshold below which DNSPs should not be required to apply the regulatory test.

Alternatively, it may be more appropriate for the Code to place obligations on the jurisdictional regulators to achieve the objectives of the regulatory test in relation to distribution assets.

The NEDF submits that there must be agreement of the Jurisdictions as a precondition to any extension of the coverage of the ACCC's regulatory test to infrastructure regulated by the Jurisdictions. At the time of the Code change, NECA acknowledged the need to consult with the Jurisdictions to resolve issues of uniformity and duplication of regulatory requirements, with a view to achieving greater uniformity in investment approval using the Code as a vehicle[3]. To the NEDF's knowledge, this consultation has not yet taken place.

A failure to achieve consistency will place DNSPs in the intolerable position of investing in an environment of ambiguity in the consultation and approval process, which could only serve to unnecessarily delay or even stifle prudent investment. The DNSPs believe their ability to manage their business should not be constrained by ambiguity or unduly prescriptive regulation.

I suggest the following representatives would be well placed to advise of the potential overlap of investment approval process within each jurisdiction on behalf of the NEDF.

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[2] Initially entitled "Streamlining the process for determining the beneficiaries of new regulated network investments" and later "Network and Distributed Resources".

[3] A network and distributed resources package – Report, NECA Code Change Panel, December 2000.

State	Representative	Organisation	Contact number
ACT	Mr. David Howe	ActewAGL	02 6293 5871
NSW	Mr. Harry Colebourn	EnergyAustralia	02 9269 4171
Queensland	Mr. Tony Pfeiffer	Ergon Energy	07 3228 7711
South Australia	Mr. James Bennett	ETSA Utilities	08 8484 5261
Victoria	Mr. Siva Moorthy	United Energy	03 9265 7824

Detailed comments on many of the issues raised by the ACCC have been provided as an Attachment. These comments must be placed in the context that the provisions of the Regulatory Test could only apply to DNSPs after the precondition above has been met.

I trust this submission and the comments will be of assistance to the Commission in its review of the Test.

Yours sincerely

Patrick McMullan
Secretary, National Electricity Distributors Forum

Attach.

Attachment – Issues for discussion

Maximising net benefits

Does the regulatory test need to differentiate between TNSPs and DNSPs?

The same ***principles*** should apply to both TNSPs and DNSPs. However, some discretion should be allowed in the application of the regulatory test between transmission and distribution networks. It is important that in its application, the ***processes*** required by the Code to implement the regulatory test should appropriately reflect the scale, complexity and number of investments at different levels of the network. If this is not the case, the regulatory test will unnecessarily complicate the approval process, at best delaying investment beyond the optimal time and at worst imposing costs which could render economic investment less efficient.

The DNSPs are presently subject to Jurisdictional regulation of most aspects of their businesses. Whilst the Jurisdictional requirements have many common elements, there are significant differences between Jurisdictions which preclude the use of a common regulatory test for investment in distribution networks. The variation n approach between the Jurisdictions is demonstrated below.

- ***NSW –*** The Ministry of Energy and Utilities with broadly based assistance has developed a "Demand Management Code of Practice"[4] which specifies the consultation processes DNSPs should follow to elicit appropriate non-network solutions.

  More recently, IPART was requested by the Premier to undertake an Inquiry into the opportunities for demand management in NSW. The Tribunal has issued a draft report recommending a range of initiatives and is presently seeking submissions from interested parties.[5]

  Furthermore, in NSW the 'Planning Guidelines' outlining community consultation responsibilities for DNSPs are being rewritten to put utilities' responsibilities in a single document. This document is being prepared by a working group set up by the Ministry of Energy and Utilities and will replace an existing document.

- ***Victoria –***Victorian DNSPs are regulated by the ESC for new network investments, requiring DNSPs to apply good asset management principles (Clause 3 of Electricity Distribution Code), which includes compliance with laws & performance obligations. Distributors are required to minimise risks associated with the failure of or reduced performance of assets in a way that minimises costs to customers.

  During the recent price review, the ESC commissioned independent analysis of the conditions and network investment requirements of Distributors to ensure the 5-year forecasts were on sound and realistic asset management plans. In the Electricity Distribution Price Determination 2001-05, the ESC structured the price controls and performance incentives in a manner that encourages efficient investment by the DNSPs.

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4 Final Report to the Ministry of Energy and Utilities and Recommended Demand Management for Electricity Distributors" Code of Practice (NSW), Demand Management Code Review Working Group, 18 May 2001.

5 Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services - Interim Report, IPART, April 2002.

The Electricity Distribution Code (Clauses 3.4 & 3.5) requires DNSPs to develop Transmission Connection Planning Report and Distribution System Planning Report on an annual basis. It provides background information to the proposed augmentation and signaling opportunities for market participation.

- ***South Australia –*** ETSA Utility's obligations for connecting and modifying customer connections are set out in the South Australian Distribution Code Chapter 3. The Electricity Pricing Order (EPO) sets out further pricing obligations for such connections, and also applies when connecting generators to the distribution system. The SA regulatory framework also controls the ability to differentiate network pricing on the basis of geographic location for most customers.

While this situation of Jurisdictional regulatory control pertains, the Test also needs to differentiate between TNSPs and DNSPs.

If so, [regulatory test to differentiate between TNSPs and DNSPs] should different approaches apply to each?

As outlined above, differences in the approach to investment approval between TNSPs and DNSPs need to recognise existing Jurisdictional controls as well as the scale, complexity and number of investments. In particular there should not be a need to carry out market modelling where projects do not have a significant market impact.

Is the current test dealing with reliability driven augmentations appropriate?

The current requirement of the regulatory test for a reliability driven augmentation, which require NSPs to minimise the net present cost of the augmentation is considered adequate. This accords with normal practice. What is an issue is the additional administrative burden imposed by the Codified process, by which the test is to be implemented.

Should reliability driven augmentations be required to follow a similar process to market driven augmentation?

No. The principles of the regulatory test should apply in an even-handed manner to all infrastructure investments. However, in the interests of streamlining the consultation and approvals process, it is convenient and appropriate to categorise the types of investment. It is also considered that in the interests of streamlining the investment process the regulatory test should involve disclosure of the pricing allocation using whatever approach is adopted as the outworking of NECA's current review of "Beneficiaries Pays" arrangements.

It is proposed that a more streamlined process might result if investments subject to regulatory tests were categorised slightly differently. They are as follows:

- Investments that have a material market impact, where it would be normal for the costs of the investment to be borne by both generators and customers in some proportion. The level of materiality would need to be defined;
- Investments that serve both customers and generators but do not have a material market impact, where non-market generators or generators below a threshold size (say 30 MW) are involved. In this instance, sharing of the costs between customers and generators may also be involved but a simplified pricing allocation could apply; and
- Where investment is required to meet network security and reliability criteria, the costs of network investment are to be borne by customers.

The additional investment category would facilitate application of the Regulatory Test to smaller generators located within distribution networks. It is unlikely that the beneficiaries cost allocation process to be developed by NECA for interconnected transmission networks would be necessary or appropriate within distribution networks.

The requirement to carry out market modelling for distribution projects which are reliability driven or for projects that do not have a material market impact due to their size adds unnecessarily to the complexity of the assessment process. At the very least, simplification of market modelling requirements is required for projects which will not have a significant market impact.

Competitive impacts of network investment

Should the test ensure an alignment between the beneficiaries of the investment with those who pay for it?

It is considered that the regulatory test and "beneficiaries pays" process currently being developed by NECA should be aligned and combined for the purposes of any consultation. This should result in significant streamlining of the process associated with large new investments.

Network and distributed resources code change package

Should the regulatory test be more prescriptive?

The present level of prescription in the test leaves it too open for interpretation and possible dispute. A clearer definition of the benefits and costs to be considered in the test and worked examples would assist.

Should the test define which costs and benefits should be taken into account?

Yes.

If so, what should those costs and benefits be?

The costs and benefits normally taken into consideration include:

- Capital costs (presently these are restricted to the electricity market which may miss costs associated with augmentation of gas supply infrastructure etc)
- Operating costs (including network support)
- Electrical losses (difference as cost or benefit, as applicable)
- Out of merit generation (difference as cost or benefit, as applicable)
- Reliability (value to customers of improved service standards, critical issue is the value of unserved energy)
- Treatment of depreciation and residual value of equipment)
- Legislated or regulated environmental costs

Other critical factors in the analysis are the discount rate and evaluation period.

Should the test include a glossary of definitions?

Yes.

If so, which terms should be defined?

All those terms which are likely to be subject to interpretation and possible dispute. In particular, definitions of the costs and benefits above.

It is considered that a few worked examples (using a similar approach to that adopted for the Negotiation Guidelines[6]) would be very helpful in providing interpretation of the Commission's intentions. Such examples should provide an indication of the treatment required for projects involving different levels of complexity and market impact.

What special provisions should be introduced for DNSPs to assist them and the market to ensure that the most appropriate investment option is pursued?

The Code should specify an investment threshold below which DNSPs are not be required to apply the regulatory test.

Any requirement to carry out market modelling for distribution projects which are reliability driven or for projects that do not have a material market impact due to their size would add unnecessarily to the complexity of the assessment process. At the very least, simplification of market modelling requirements is required for projects which will not have a significant market impact.

Timing delays

Have the problems of time delays been sufficiently addressed in the network and distributed resources code change package?

Yes. The processes for TNSPs and even the abbreviated process for DNSPs are considered to impose a significant burden and time delay. In the case of DNSPs, the Codified arrangements do not always align with Jurisdictional requirements.

Other issues for consideration

Should the Commission clarify its optimisation of network investment that has been assessed in accordance with in the regulatory test?

Yes. Inter alia, Clause 6.2.2 of the Code requires the ACCC to seek to achieve:

> *(d) an environment which fosters an efficient level of investment within the transmission sector, and upstream and downstream of the transmission sector; and*
>
> *(i) reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions;*

It is therefore considered incumbent upon the ACCC to clearly state its intentions in respect of the optimisation of network investment.

Is the choice of discount rate, being the rate appropriate for the analysis of a private enterprise investment in the electricity sector, still appropriate?

The NEDF considers that a discount rate appropriate for private investment will not provide the appropriate outcome for regulated network investments in all circumstances.

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6 Statement of Principles for the Regulation of Transmission Revenues – Guidelines for the Negotiation of Discounted Transmission Charges, ACCC, 3 May 2002.

The existing networks have been progressively developed, by choosing from augmentation and design options at each stage. Each choice has been made using a discount rate appropriate for relatively low risk investments. The networks are largely optimal and within regions, have relatively low costs of losses and generally small levels of out of merit generation, which continue to benefit customers.

To move towards a cost of capital reflecting higher risk would result in an inappropriately short-term focus for investments. The inevitable result would be a move to the minimum sized, least capital cost solution, which would be accompanied by much higher:

- cost of losses;
- risk of non supply, where this is factored into account;
- out of merit generation; and
- opex.

Furthermore, the pricing associated with regulated network investments reflects their economic life and would not be aligned with the investment process.

Such an approach would be of particular concern if applied to regulated network investments designed to meet specified regulatory reliability standards.