30 September 1999

Mr Michael Rawstron
General Manager, Regulatory Affairs Electricity
PO Box 1199
DICKSON ACT 2602

Dear Mr Rawstron

PROPOSED NATIONAL ELECTRICITY CODE CHANGES

Powercor provides the following submission in response to the Commission's Draft Issues Paper dated September 1999 entitled "Applications for Authorisation, Application to Vary an Access Code - National Electricity Code, Network Pricing Code Changes".

Previous submissions

Powercor notes that the Commission's Draft Issues Paper states that interested parties are invited to provide to the Commission those submissions that have previously been submitted to the earlier NECA Review. Since many of the issues raised in the previous NECA review are the same as the current process, Powercor attaches for your consideration a submission to NECA dated 23 September 1998 which was made jointly by 4 Victorian distribution businesses (Citipower, Eastern Energy, United Energy and Powercor).

Further submissions

As well as considering the joint submission that was made to NECA by the four Victorian distribution businesses, Powercor asks the Commission to consider the following specific issues.

Unbundling transmission and distribution charges

The underlying intention of unbundling network charges is based on the belief customers will respond to the disaggregated price signals enabling them to make decisions in respect of their electricity supply more efficiently. Powercor is generally supportive of such an approach, however is concerned that the benefits of unbundling network charges will not eventuate in practice, due to the high costs associated with the new methodologies and supporting systems (particularly IT systems) that will be required to enable unbundled of network charges. A report by NECA working group 2 concerning unbundling of transmission and distribution charges has estimated that the costs associated with the development of billing systems of distributors will be $0.25 million per distributor. Further, it is estimated that the costs to retailers may be as high as $1.25 million. The NECA working group estimated that the total cost to the market of unbundling could be as high as $30 million. Powercor doubts the customer benefits would be of this size.

Powercor does not currently engage in unbundled charging or provide unbundled accounts. Further, Powercor's billing system is not capable of providing an unbundled network accounts. Powercor estimates that formulating an appropriate unbundling methodology, training staff to use and understand the new methodology, upgrading systems to process the information required for unbundling, and upgrading accounting systems to adequately deal with the requirements of unbundling will be costly. Powercor does not consider that these costs will be outweighed by any economic benefits that may flow from unbundling charges.

Service standards

Powercor supports the use of service standards as part of an incentive based regulatory regime. As such Powercor generally supports the introduction of uniform national service standards. However, Powercor is concerned that the service standards that it will be required to meet and publish have not yet been determined.

The proposed changes to the Code itself do not state what the service standards will be. The NECA final report states that the service standards will be based on a combination of those currently published by OFFER, ORG, IPART and those suggested by a NECA working group and the Commission. It is imperative all these regulators agree on a common set of service standards so that Powercor is not required to comply with a second or third set of indicators determined by jurisdictional regulators that are inconsistent with those stipulated under the National Electricity Code.

Powercor is currently expending significant resources to comply with the ORG's latest changes to service standards associated with the 2001 Price Review. Powercor does not wish to expend a similarly high amount of resources to comply with additional sets of service standards. Powercor considers such duplication costly and inefficient.

Network by-pass

Whilst supporting the right to by-pass, Powercor considers that any by-pass should be efficient.

Powercor is concerned that the proposed changes to clauses 6.5.8 and 6.14.6 of the Code are not sufficient to ensure that by-pass is efficient. Further, the proposed changes to the Code, which make the jurisdictional regulator take into account potential loss of revenue resulting from by-pass, do not state the principles to be followed by the regulator to take that loss into account.

Powercor is concerned that an automatic right to by-pass may not produce the best outcome for society in general and existing customers who do not by-pass the distribution network. The Victorian Government has established complex pricing structures that entail cross subsidies between users. By permitting by-pass that is inefficient, distribution businesses will be placed under considerable pressure to reduce the Government cross subsidies that have been put in place to ensure all customers receive electricity supply at a rate considered acceptable by all segments of the community.

Powercor seeks for a requirement to be placed in the Code that requires by pass to be efficient.

Conclusion

I would be pleased to discuss with you any of the issues raised in this submission. I can be contacted on (03) 9679 4465 or alternatively at bcleeve@powercor.com.au.

Yours sincerely

[signed]

Brent Cleeve
ECONOMIST REGULATION

Attachment: Submission to NECA dated 23.9.99

NECA Transmission and Distribution Pricing Review

Joint Submission of Four Victorian Distribution Businesses:

Citipower

Eastern Energy

Powercor

United Energy

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23 September 1998

Contents

1. Overview of Submission

1.1 Introduction

The four Victorian Distribution Businesses (Citipower, Eastern Energy, Powercor and United Energy) provide this submission in response to the NECA Options Papers which sought to present "a package of practical, policy orientated options for the way forward". Following a round of seminars and consultations, NECA intends to publish a draft report with a view to a final report to Governments and the ACCC before the end of 1998 and as a basis for possible changes to the National Electricity Code.

1.2 Structure of Victorian Distribution Businesses ("DBs") Responses

Four Victorian DBs provided a joint submission dated 31 March 1998 in response to the Issues Paper circulated by NECA in December 1997. This response builds upon that earlier submission and addresses the issues raised in the NECA Option Papers and the four background papers produced by NERA. The issues have been grouped into eight areas which are:

- arrangement for charging for connection;
- incidence of transmission use of system ("TUoS") charges;
- allocation and structure of TUoS and distribution use of system ("DUoS") charges;
- service benchmarks and negotiation of transmission charges;
- unbundling of TUoS and DUoS charges;
- treatment of embedded generators;
- NSPs' annual planning reviews; and
- inter-regional hedging, firm access and a framework for non-regulated interconnectors.

Each topic has been covered in an individual section which, taken together, address the issues raised in the options papers.

1.3 Detailed Proposals

In each of the eight key topic areas addressed in this report, the process is one of commenting on the issues and main preliminary conclusions set out in the NECA options paper dated July 1998.

A concern which recurs throughout this submission is that considerably more detailed analysis of the various options needs to be undertaken before any draft proposals are made by NECA. The comments made on the principles are of value in the process, however, constructing detailed proposals will allow a clear analysis of the risks, benefits and practicalities by all industry participants.

1.4 Transition Arrangements

The position of the Victorian DBs is that the review provides an excellent opportunity for the industry to develop the optimal model to address the issues under review. This opportunity should not be wasted. This means that the best model is endorsed and then an analysis undertaken to assess the cost and price disturbance in moving from the old regime to the new. From this analysis a transition path from the old to the new can be designed which provides a smooth transition to the new arrangements. Any compromises to address historical precedents should be addressed in the transition arrangements and not through amendments to a flawed model so as to rationalise past decisions.

For participants to have sufficient confidence to make the required investment decision, a stable regulatory environment is needed such that investments are not undermined by continual rapid changes to the market framework. Thus only those changes which provide sufficient benefits against a defined set of guiding principles should be enacted. To enable this to be properly managed, smooth, sensible transition arrangements are required to be put in place such that participants are able to invest in the industry with the prospect of not having the value of their investments dramatically and unexpectedly eroded.

1.5 Transmission and Distribution Pricing Approaches

The approach to much of the material produced suggests that transmission systems and distribution systems have significant similarities and should be treated on a comparable basis.

Whilst there are some similarities, there are substantial differences when considering all aspects of transmission and distribution networks. These range from the practical considerations such as design operation, and daily reconfiguration, to the responsibility for regulating and controlling the businesses. The complexity of the distribution network is far greater with a large number of nodes and with typically half a million end users connected. In contrast, transmission systems will typically have ten customers.

The Victorian DBs believe it is wholly inappropriate to assume that what is correct for transmission systems will be correct for distribution systems, and that the same solutions can be applied for the pricing issues of the two distinct systems.

In addition, network pricing and standards are linked and should not be treated separately. It is therefore critical that the regulation of prices and standards rest with the jurisdictional regulator.

2. Arrangements for Charging for Connection

2.1 Background

NECA has endorsed existing charging arrangements for shallow connection costs on the basis that ‘it is both efficient and equitable to allocate the full costs of dedicated connection assets to the relevant participant provided that stranding and prudential risks are handled in a way that neither imparts an inefficient cross subsidy to the participant nor imposes an inefficient barrier to entry’.

The four Victorian distributors support this view.

2.2 Connection Charging Methodology

However, we do not support NECA’s proposals for charging deep connection costs to new entrant generators while allowing incumbent generators access to transmission at no cost. We see this as a major barrier to entry in the generation sector with attendant adverse implications for energy market competition, reduction in the economically efficient supply of electricity, and achievement by the electricity supply industry of its long term greenhouse gas reduction obligations.

The first aspect to observe is that the market has a “Top End” problem (ie there is insufficient peaking plant generation capacity). To assist in managing this, new generation plant (particularly mid-merit/peaking plant) should be encouraged. In addition, the location of this type of plant can be of significant importance. It is likely to be the case that a large generation plant will need to be located close to its fuel source as this will provide the greatest economy. Fuel cost benefits will outweigh transmission location signals, but this is not a reason to ignore such locational signals. However, for certain plant, particularly smaller installations it is desirable to ensure that barriers to entry do not exist and that the correct incentives are in place which will ensure the correct locational decisions are made.

The deep connection approach has a number of shortcomings and potential pitfalls particularly when considering the interaction with system reinforcement. The need for system reinforcement often arises as a consequence of changes in the configuration of demand and generation on the system as a whole and not just as a result of a decision to connect by an individual party. It is arguable whether a requirement for reinforcement in one particular area is a result of:

- a new generation development;
- a decision not to close an existing generator;
- demand growth in one specific area;
- demand decline in another area; or
- previous transmission or distribution network development decisions.

More likely it is a combination of all these factors.

A policy by which a potential new connection is made responsible for all remote reinforcement would be an extremely arbitrary approach to charging. It also implies that existing users have a right to use the system on terms which would not be available to future users (ie their rights would be preserved). Such an approach could lead to different users at similar locations with similar characteristics paying very different charges.

The specific shallow connection assets involved can be properly attributed as required by specific users as connection assets and charges for those assets can be levied on the user. Due to the interactive nature of the rest of the system it is not possible to allocate specific assets from these to specific users except on some arbitrary basis. As such the use of “shallow” connection costs can be viewed as cost reflective, but the use of a “deep” connection cost approach employing arbitrary rules could potentially raise barriers to efficient entry by being inappropriately discriminatory and this would lead to economically inefficient outcomes.

2.3 Conclusion

The deep connection approach would unreasonably:

- be a barrier to entry for new generation;
- be based on arbitrary rules, and is potentially discriminatory in nature;
- lead to similar users, making similar use of the system, paying different charges;
- be economically inefficient; and
- be complex and potentially costly to administer.

The four Victorian DBs do not support the use of deep connection charging but wish to see shallow connection costs remain the policy.

These issues are also addressed within Section 3.

3. Incidence of Transmission Use of System Charges

3.1 Background

This issue has been perhaps the most contentious of those canvassed in the NECA review. Debate has been polarised between those (including distributor, customer and cogeneration interests) who contend that existing generators should pay a share of TUoS charges and those (predominantly incumbent generation interests) who argue for continuation of existing arrangements under which existing generators pay only direct connection costs.

This section reiterates our concerns about existing arrangements (outlined in our initial submission of 31 March 1998 to NECA), assesses how well the options canvassed by NECA meet those concerns, and suggests how this matter might be taken forward.

Due to the pervasive linkages between network pricing provisions, this discussion also touches upon NECA options for charging generator connection and the treatment of embedded generation.

3.2 Concerns Outlined in our Initial Submission

We noted in our initial submission that under existing code provisions new generators would face one of two pricing outcomes:

- either the new generator would be asked to pay 'deep' connection charges ie, the full cost of new assets required to transport the generator's output to the centre of load; or
- customers would be required to pay for the transmission network augmentation.

In arguing that all generators should pay at least 50 percent of TUoS charges we commented that:

> *'Of the two options above, the first option sees a generator being allocated a charge that would not be experienced by its competitors. And, in fact, the generator simply may be the 'straw that breaks the camel's back' where it is the load from all existing generation that is contributing to the need for an augmentation. This would appear somewhat unfair.*
>
> *Under the second option listed above, customers are being asked to pay for a generator augmentation while the generator is locating its plant with no locational signal. It may have been the case that an alternative siting for this or another generator may have been close to the point of load with minimal additional capital cost to the generator. Overall such an alternative would have been economic, however, was not adopted because the generator never saw the full pricing signal.*
>
> *Customers would then be required to pay for this sub optimal locational decision. This model too is unfair.*
>
> *The only equitable model appears to be allocating charges to generators based on the cost of transporting power to the notional centre of load, regardless of whether that generator is 'existing' or 'new'.'*

3.3 Assessment of NECA Approach

In essence, the approach currently proposed by NECA retains the barrier to competitive generator entry and inefficient pricing outcomes outlined above and does nothing to alleviate the concerns which we have expressed about that approach.

In specific terms NECA's 'preliminary conclusion' is that:

- *'**location signals for new generation** should be provided by a requirement for generators to pay 'deep' connection charges in specific defined circumstances: where substantial investment in the shared radial network is required as a result, where the benefits of that investment accrue to one user and where the costs can be clearly identified. Existing generators should not be shielded from the effects of those new locational decisions ie, there should not be free 'firm access' for incumbents. On the other hand, new generators embedded in the sub-transmission or distribution networks and that contribute to the relief of local congestion should receive an appropriate rebate on network charges;*
- *although NECA would welcome further views on this issue, the balance of the arguments on efficiency and equity grounds for seeking to provide locational signals for all, including existing, generators by **requiring generators to pay a share of network charges** is probably not proven.'*

In adopting this position NECA appears to have been persuaded by arguments put forward by the National Generator Council supported by a report prepared for them by Putnam Hayes and Bartlett.
The Victorian DBs **fundamentally disagree** with the arguments put forward by the National Generator Council and others, that:

- current TUoS pricing methodology does not provide good locational signals but in any event sufficient locational signals for new generation are provided through the energy market design, deep connection charging and negotiation of rebates to embedded generators which relieve congestion in distribution and sub-transmission systems;
- recovery of part of the TUoS costs from generation would result in higher energy prices and could distort efficient despatch if undertaken through a variable charge, or generation investment/retirement if undertaken through a fixed charge; and
- recovery of TUoS costs entirely from customers is the most economically efficient method in that distributor charges to customers can be designed in such a way as to minimise distortions in network use.

The following issues require further consideration:

3.3.1 Locational Signals for New Generation

While it is true that the existing CRNP model would not provide effective locational signals for either loads or generation, NECA has identified (page 8, Options Paper 1) possible modifications with the potential to help remedy this problem. These include using asset revenue requirements that relate to the cost of augmentation, adjusting each asset's revenue requirement for prevailing congestion levels and providing equal and opposite pricing signals to loads and generation derived from these adjustments.

Indeed, the problem of low entry pricing signals in low congestion areas of the network, could be alleviated by the use of power flow modelling rather than fault level modelling. This would lead to a more economically representative method of implementing CRNP. Alternatively, the effect of over pricing the poorly utilised areas of the transmission network could be partially eliminated by the use of "capacity utilisation" in the pricing model. Thus only the capital costs of utilised assets are allocated directly to particular customers (ie end users or generators), whilst the remaining underutilised capital assets are allocated under a "postage stamp" arrangement.

This option exists in the model developed by the National Grid Management Council ("NGMC"). This approach to locational signalling via a "reasonable" TUoS charge to all generators would lead to much more economically efficient outcomes than at present. However, the benefits of this proposed modification to CRNP should be closely evaluated against the costs, in particular given the complexity of the existing methodology.

While adding to the complexity of CRNP these potential modifications warrant further examination. However, any modifications should be in the context of a broader review of pricing arrangements and the establishment of an appropriate transition path (refer to Section 4). It is not entirely certain that modification to CRNP will provide the optimal solution and other methodologies should be considered in parallel.

As NECA has recognised, locational signals provided through the market design (such as the application of inter and intra-regional loss factors and regional spot pricing) are too low, are transitory and need to be supplemented by network pricing signals. However the NECA proposals for achieving this - negotiation of deep connection charges and rebates to embedded generation – face substantial problems of their own. Both may involve contentious and protracted negotiations with potential for frequent recourse to arbitration.

Negotiation of deep connection charges will require agreement on alternative investment scenarios with and without the new generation, arrangements to avoid asset stranding and provisions to vary charges when initially dedicated network assets become shared with other network users. The protracted nature of these processes will further undermine network efficiency and reliability. It will not lead to efficient market outcomes.

Similar issues will arise with negotiations on rebates to embedded generation as well as the further complexity of allocating any savings in TUoS charges which may be made by the host distributor. (The NGMC and TransGrid have argued against any pass-through of such savings to embedded generation in that they involve cost transfers rather than genuine cost reductions.)

3.3.2 Distortions in Network Use

As NECA has noted, in a competitive market there is no guarantee that generators will be able to readily pass on TUoS charges through pool or contract prices. However, it should be recognised that any price increase in the pool is offset by a corresponding reduction in customer supported TUoS charges.

Whilst it seems that generators will come under some pressure to absorb these costs by obtaining further efficiencies elsewhere in their operations, not all costs will be unsupported by the market.

If generators were required to bear part of the cost of investment in the meshed network they could play a more constructive part in investment decision making and establishment of service standards than they do while customers bear all the costs.

To the extent that generators are unable to absorb transmission costs, those using more transmission resources would pay more than those more adjacent to loads who use less of the transmission network. This is as it should be under application of user pays/cost reflective principles. It is certainly preferable to the situation which will prevail under the current NECA proposals where incumbent remote generation well served with transmission assets at no cost to themselves would retain long term competitive advantages over new entrants including those using much less in the way of transmission resources. As a consequence new entry would be deterred and competition in energy markets would be less than it should be. Environmental benefits from cogeneration and other more greenhouse friendly generation would also be deferred.

3.3.3 Charging TUoS to Generators

The transmission capacity required is a function of the level and the location of both demand and generation. It would therefore be appropriate for both generation and demand to be charged based upon their capacity requirements. Similarly in planning the system, the presence of generation in certain locations and of demand in other locations can save costs of reinforcement. Hence signaling both the costs which may be incurred and the savings which may be achieved by the transmission system in meeting the requirements is needed to influence siting decisions of both demand and generation.

From the point of view of transmission and viewed, on a nodal basis, increases in generation in a given location can be viewed as equivalent to decreases in demand at that location. Conversely decreases in generation can be viewed as equivalent to increases in demand. That is, demand is equivalent to negative generation, and generation is equivalent to negative demand. This suggests that TUoS charging must be on both demand and generation.

On this basis, generators should pay a proportion of the TUoS charges which provide locational signals. To the extent that TUoS is reflected in pool prices, market signals are enhanced.

Whilst it is clear that generators should pay a proportion of TUoS charges, the issue of how much the generators should pay needs to be addressed. There is no defined single point of delivery between a generator and a supplier, thus any particular apportionment of the TUoS charges is variable by location. Earlier versions of the transmission pricing models that were in existence prior to the finalisation of the Victorian and national regimes were based on the LRMC of new generation and new load. Generators typically paid 50% of TUoS charges under these regimes. International comparisons, including those made within NECA's Transmission Pricing: International Developments, show that generators pay TUoS charges with a variety of percentages being applied.

The four Victorian DBs recommend generators pay at least 50% of TUoS charges.

The objective must be to put in place the best model and then address any transition issues and not construct a model which adversely affects competition and efficiency of pricing signals.

3.4 Conclusion

The Victorian DBs have serious concerns regarding the NECA framework of no TUoS charges for generators, negotiation of deep connection charges for new entrants and rebates for embedded generation. Instead, we would prefer a framework that is more equitable and competitive.

The Victorian DBs suggest the following approach:

- shallow connection charges;
- improved locational signals; and
- generators to pay at least 50% of TUoS charges.

4. Allocation and Structure of TUoS and DUoS Charges

4.1 Background

Whilst the Victorian DBs are broadly supportive of the findings and the debate presented by NECA in the options papers, a number of issues still require further detailed consideration and are discussed further below.

4.2 Balance Between Cost Recovery and Efficiency Promoting Signals

We propose that the issues of cost recovery and efficiency signalling be dealt with discretely by virtue of a pricing method for new investment which involves the allocation of new asset costs based on the full benefits gained from the incremental investment. This will allow the most appropriate efficiency signals to be established whilst still allowing appropriate cost recovery for the existing asset base. This approach is outlined more fully within the next section.

4.3 Effectiveness of CRNP and postage stamping as a means of providing efficient location and congestion signals and potential alternatives

It is recognised that both CRNP and postage stamping have significant limitations.

Whilst CRNP should in theory provide efficient locational signals and equitable cost recovery, the options paper correctly identifies a significant number of deficiencies with CRNP. Additionally, the 1996 IPART determination confirmed that in the case of mature networks CRNP prices were negatively correlated with congestion.

In practice CRNP does not always adequately serve the objectives of providing efficient location and congestion signals. Postage stamping, on the other hand can lead to cross subsidies which promote inefficiencies.

We do not believe that the deficiencies of the CRNP model can be best addressed through extensive further modifications. The CRNP process is already overly complex and it is unlikely that further tampering will satisfactorily address its deficiencies.

4.4 TUoS Charges and Locational Signals

It is critical that transmission pricing provides the strongest possible locational signals to allow for the efficient siting of generators and loads. The pricing should however be consistent with the established pricing principles.

We believe that “Common Service” costs should be allocated in accordance with asset usage as per other shared network costs. On this basis these costs will also apply location signals.

It is important that the efficiency of location pricing framework principles are not diluted because of social policy issues. We strongly recommend that equalisation mechanisms or CSOs be employed on a jurisdictional (ie state) basis. This approach has already been proven to work effectively in Victoria.

4.5 The balance between CRNP and postage stamping

We support NECA's view that the establishment of an appropriate balance between CRNP and postage stamping for distribution businesses is best left to the discretion of individual jurisdictional regulators. A set of nationally developed principles can most effectively be implemented at a jurisdictional level. Establishment of the appropriate balance between CRNP and postage stamping requires full consideration of local conditions and social policy issues are best addressed through a jurisdictional determination.

4.6 Structure and weighting of the elements of TUoS and DUoS charges

We fully support the view put forward by NECA that the establishment of a set of high-level nationally-consistent principles should be within the Code. However, distribution network pricing is a matter for the jurisdictional regulator. This approach best captures the specific characteristics of each of the jurisdictions and respects transitional arrangements supported by jurisdictional regulators. As stated in our previous submission, we believe that Part D provides an appropriate national framework for distribution prices.

The Victorian DBs support the use of a demand-based component within DUoS as a mechanism by which to encourage demand side management and enhance network efficiency. DNSPs are likely to give consideration to weighting the demand element so as to reflect the costs of providing service to a particular class of customer and the characteristics of their particular network.

4.7 Conclusion

The Victorian DBs recognise that the continued use of a combination of CRNP and postage stamp pricing in the short to medium is the only practicable alternative. It is important that NECA continues to explore alternatives and on this basis we would recommend closer consideration of a reliability improvement based calculation for new investment in parallel with a more traditional cost reflective pricing approach for existing (ie pre-national code) assets.

Whilst we strongly support the rationale for changes, any changes to the allocation and structure of TUoS and DUoS charges must be accommodated within an overall transitional framework that allows for maximum market and regulatory certainty for all participants.

5. Service Benchmarks and Negotiation of Transmission Charges

5.1 Background

The Options Paper identifies three specific issues for discussion in relation to service benchmarks and negotiation of transmission charges, namely:

- the proposed criteria for determining benchmark levels of service by NSPs;
- the scope for bilateral negotiations about premium levels of service, entirely outside NSP's revenue caps; and
- the necessary framework for negotiations to ensure a level playing field between the parties.

It is evident that NECA is seeking to investigate this issue in significant detail through the establishment of the Transmission and Distribution Pricing Review Specification and Negotiation Working Group ("the Working Group"). It appears that *inter alia* the Working Group will be seeking to further clarify the above issues.

5.2 Proposed Criteria for Determination of Benchmark Levels of Service by NSPs

NECA currently supports the definition, on a 'reasonable endeavours' basis, of benchmark service levels for NSPs beginning with transmission. NECA has suggested that these benchmarks need to be auditable, focused, practical and cost-effective, equitable, compatible and consistent, and provide incentives for NSPs to achieve them. The benchmark standards themselves and NSP performance against them should be published and incentives for performance against them should be included in revenue cap arrangements.

The Victorian DBs support the application of an incentive based regulatory regime for the regulation of Network businesses. Incentive based regulation, as against heavy handed regulation, is the model which is consistent with the intent of the Hilmer competition reforms and the COAG reforms for the electricity industry.

The Victorian DBs support a regime of competition by comparison (ie comparison to peers or benchmarks), as being consistent with the incentive based approach to regulation. Competition by comparison has been adopted by the Victorian Office of the Regulator General, and has proven successful in that regime.

The incentives associated with the competition by comparison can be further strengthened by the introduction of forward looking financial incentives at the time of the price review.

If there is a concern that the incentive based approach does not sufficiently protect customers the model can be supplemented by the specification of minimum service standards. The minimum service standards provide a performance safety net for all customers. It is strongly recommended that any minimum standards are set and left at a level which does not interfere with the incentive regime. If the NSPs believe that the regulator is prone to modifying the standards, perverse incentives may be created, with such incentives ultimately being to the customers' detriment.

The regime described above should be left to the relevant regulator to implement. The establishment of any incentive mechanism, benchmarks or minimum standards must be integrated into NSPs' periodic price review process as it is not possible to decouple price and performance. As such it is inappropriate and impractical to include the mechanisms for providing competition by comparison within the National Code.

5.3 Scope for Bilateral Negotiations about Premium Levels of Service

NECA has suggested that bilateral negotiations could occur based on requirements by users for premium levels of service beyond the minimum standards at commercial rates outside of the price control prevision. Negotiation of those premium levels of service might focus on:

- lower failure rates of nominated network elements;
- increased maintenance effort; and/or
- network augmentation.

Whilst not disagreeing with NECA's view in relation to the above, we note that only one of the three items for negotiation relate to performance outputs. Importantly, most effective performance monitoring is either output based (a partial indicator) or based on a total factor (ie inputs and outputs). It is critical that service standard measures give strong consideration to outputs. As such, the Victorian DBs prefer to focus negotiations with customers on outputs, and should not be obliged to engage in negotiations about inputs. We acknowledge, however, that there are some circumstances where it is not possible to define the service purely by outputs. A key feature of micro-economic reform is to allocate the incentives and risks associated with asset management to the network service providers, rather than to customers.

As stated in our initial submission, negotiation should be conducted in a 'fair and reasonable' manner in order to protect other parties in the negotiation process without unduly restricting the results of the negotiation. The definition of fair and reasonable should be left to the jurisdictional regulator to determine and this would be consistent with other areas.

There should be a disputes resolution process, however, the precise mechanism does not have to be specified at this stage. In that, the incentive based arrangements would be agreed with the Regulator, the disputes procedure would be via the Regulator and hence not specified by NECA.

Other submissions also supported the concept of negotiation to varying degrees. We support IPART's comments that the provisions relating to the customers' ability to negotiate, and NSPs' obligations to do so, be clarified by NECA.

5.4 Conclusion

To address issues of information and negotiating asymmetry, NECA has suggested it may be appropriate to impose obligations on NSPs to negotiate in good faith and provide access to necessary information, and to provide for appropriate dispute resolution arrangements.

We accept the need to ensure a level playing field to the extent that guidelines are established which detail information that is considered to be commercially sensitive as being 'off-limit'.

Any guidelines for negotiations should, where possible, focus the negotiations on performance outputs rather than inputs. Such an approach allocates the incentives and risks associated with asset management to the network service providers rather than to customers. This is consistent with reform objectives

6. Unbundling of TUoS and DUoS Charges

6.1 Background

The NECA Issues Paper notes that Distribution customers often see a single network service charge that combines both TUoS and DUoS.

In its Options Paper NECA has stated that unbundling of TUoS and DUoS will "*make a worthwhile contribution to removing the disadvantage of information asymmetry and thus assist in providing a more level playing field including in relation to negotiations over standards of service by NSPs*." However, NECA also states that in relation to the concerns outlined by the Energy Users' Group, "*Unbundling will not of itself provide a solution to these perceived disadvantages*."

The Victorian DBs assume that any suggestions of unbundling of TUoS and DUoS relates to the separation of charges on bills, rather than any proposal to alter the contractual arrangements across the industry.

6.2 Principle of Unbundling

In general, the Victorian DBs support the principle of cost reflective charging where practicable and where this encourages price responses which increase the economic efficiency of providing the service. Unbundling of TUoS and DUoS charges may help enable this, but unbundling for its own sake will not necessarily achieve the economic outcomes required, and may do more harm than good.

There are a number of points which need consideration; these are set out below:

- The current practice is to use average network prices (combining TUoS and DUoS) for the majority of customers. Ideally it would be possible to calculate a spectrum of fully cost reflective charges for customers based on their specific demands. However, it is impractical to individually calculate network prices for each and every customer. Therefore, the approach of averaging TUoS and DUoS charges is necessary for the majority of customers.

- The allocation of the fixed and demand components of the TUoS charge are likely to prove problematic. The establishment of an allocation basis for fixed costs, whether it be based on customer numbers or energy usage is likely to be arbitrary and is unlikely to be truly reflective of a customer's contribution to the fixed charge. Allocation of the demand component is even more difficult. Customers are billed based on their maximum demand at any time of year. Distributors are billed based on an average maximum demand for the whole network for a number of peak days. As a result of the lack of coincidence between these two demand measures, it is impossible to relate system demand (on which TUoS is billed to the distributor) to a customer's maximum demand. In addition, customer charges would be subject to significant variability depending upon the extent to which a customer's demand peak is coincident with the overall system demand peak.

If the approach requires the DNSPs to build systems for the purpose of unbundling TUoS and DUoS, there is the requirement to develop common specifications and then agree on funding responsibilities. The costs associated with systems development are likely to be significant and are most likely to be recovered through charges to customers. These costs must be considered in assessing any net benefits arising from unbundling.

6.3 Impact of Unbundling

If the unbundling of TUoS and DUoS charges is to include alterations in the contractual relations between retailers, DNSPs and TNSPs, and fuller cost reflectivity is to be introduced, the following may be required:

i) For Transmission Charges:

  - transmission businesses to calculate cost reflective prices;

- transmission businesses to separately contract with individual customers (or their retailers) and establish necessary customer service systems (call centres, enhanced billing systems, etc)
- transmission businesses to separately bill individual customers (retailers) for transmission charges;
- transmission businesses to take risk of large customers avoiding a disproportionate level of charge relative to the cost savings;
- transmission businesses to take risk of year to year volatility of charges; and
- transmission businesses to analyse benefits of embedded generation.

ii) For Distribution Charges:

- distribution businesses to remove transmission from their charges; and
- distribution businesses to calculate network charges on a cost reflective basis taking due account of urban/rural variations.

iii) For Retailers:

- pay transmission and distribution charges separately;
- bundle all charges together where appropriate;
- show unbundled charges where requested; and
- construct cost reflective/retail tariff charges on either an individual customer basis or on a localised geographic basis.

iv) For Customers:

- full cost reflective prices;
- significant increase in rural prices; and
- even within seemingly homogeneous built up areas customers will see differing price depending how the DNSPs and TNSPs have located and configured their networks relative to the location of the customers premises;

To achieve the benefits of unbundling will require some significant investment in developing new methodologies and supporting systems to put an unbundled system in place.

The net result will be a significant change in the prices charged to all customers with some major price disturbances.

The benefits of unbundling have not been quantified whilst the costs of system development and the social costs of the price disturbance are likely to be substantial. Although parallels can be drawn and lessons learnt from the unbundling of charges within the telecommunications industry, there are greater inherent constraints in electricity networks that may marginalise the benefits of unbundling. It is not clear what the magnitude of the benefits of electricity network charges unbundling are (if any). It is important to quantify these benefits first, then develop the process to realise these and then estimate the costs of developing systems to support these. A cost benefit analysis can then be carried out and a way forward agreed.

In addition, whilst the current retail pricing regime is in place, that is Maximum Uniform Tariffs (“MUTs”), the retailer has limited scope to pass the effects of unbundling through to its customers. This situation will change when MUTs finish on 31 December 2000. However, this needs to be considered as part of any transition arrangements.

6.4 Conclusion

Whilst the Victorian DBs see some benefits in unbundling, we believe that the costs are likely to far outweigh the benefits and hence we do not support the unbundling of TUoS and DUoS charges.

To progress this issue further would require detailed analysis of the costs and benefits, such that there is a clear, proven case that unbundling of TUoS and DUoS and a move to full cost reflection is economically justified. Then a detailed transition plan which manages the price disturbance aspects would need to be drawn up.

7. Treatment of Embedded Generators

7.1 Background

As we noted in our initial submission, "*the allocation of cost reflective network charges to all generators would see efficiently sited generators, such as embedded generators, receiving the appropriate competitive benefits. This approach seems to be far more desirable than creating artificial mechanisms that favour an embedded generator over another generator which may site at a similar location but connect directly to the transmission grid*".

However, we accept that negotiation of arrangements on the treatment of embedded generation will continue to be necessary until clearer congestion signals are available from the energy market itself and through network pricing.

7.2 Benefits of Embedded Generation

To enable satisfactory arrangements to be put in place between embedded generators and NSPs, both parties must have appropriate incentives. It is not unreasonable for embedded generators to share benefits conferred by virtue of their position on the system or by other characteristics.

The incentives on each party should be the sharing of benefits/cost reductions, and may potentially include such benefits as:

- system reinforcement postponement;
- effect on system planning;
- constrained operation;
- losses; and
- reactive power.

Each of these are outlined below.

7.2.1 System Reinforcement Postponement

At the “deep” level, if the presence of the embedded generator actually results in the avoidance of a remote reinforcement which could be in the transmission network, then the resultant benefit could be identified and such savings shared. The requirements for standby supplies at the generators’ premises will reduce the prospect for any savings at the “shallow” level as assets are still likely to be needed by the embedded generator so as to provide standby. Deeper in the system, not all the assets may be required for standby so some benefit is possible.

These benefits need specific modelling on a case by case basis.

7.2.2 System Planning

For the DB to take account of the capacity value of embedded generators in planning their systems, contractual and operating agreements need to be put in place between the parties covering the generator’s contribution to system security.

These benefits are a function of the individual generation installation.

7.2.3 Constrained Operation

There are potential opportunities for embedded generators to increase output or to generate only at times of peak system demand. The majority of the benefits would accrue to the embedded generator directly via the energy market or potentially from ancillary payments.

However, such running regimes may avert the need for system reinforcement in specific parts of the system where demand is increasing. These benefits need specific modelling on a case by case basis.

7.2.4 Losses

Losses are applied to energy purchases and would not be a network benefit that would be shared between the embedded generator and the network service provider.

7.2.5 Reactive Power

Embedded generators could provide local sources of reactive power, however, these are ancillary services which would be remunerated through a different route.

7.3 Apportionment of Benefits

There is scope for the distributor, retailer and embedded generator to share the benefits of embedded generation, and hence the end use customer is more likely to benefit from embedded generation.

The benefits associated with the network, both transmission and distribution, are addressed below. These benefits have a number of common attributes. They are potential future benefits and are marginal benefits only. It is also likely that a single generator on its own will not accrue any significant benefits but a number of generators located in the same area may provide some benefits in terms of network deferrals.

The other significant feature is that the potential benefits of embedded generation may never actually accrue, hence the distribution business takes some risk in crediting each embedded generator with a share of benefits which may not be realised. Thus the distributor must share in the potential benefits so as to have an incentive to negotiate terms for embedded generation. The issue of stranded network assets also needs to be considered and this may be a feature of any negotiation of benefits.

The analysis of network benefits can only be carried out on a case by case basis by applying the generator characteristics and operating regime to the specific network.

This analysis can be time consuming and costly.

It is inappropriate to carry out such analysis for small generators which probably provide little or no benefits/cost reductions on an individual basis. Large numbers of small generators similarly located may provide some network benefits. Larger generators may provide directly quantifiable benefits which can be qualified with some detailed modelling and analysis.

7.4 Conclusion

Embedded generation can potentially, over time, reduce the need for upstream investment and hence reduce costs and charges to customers.

Benefits/cost reductions for generators should be calculated on a specific basis and an appropriate sharing negotiated between the parties of the benefits of these circumstances and any performance guarantees that the embedded generator is prepared to contract for. In the case of small generators, detailed analysis of benefits may not be appropriate given their relative small size and a standardised regime may be a better option.

There is also some regulatory risk/uncertainty which must be clarified. Any disputes that arise from the failure to conclude satisfactory terms between distributors and embedded generators should be the preserve of the jurisdictional regulators and not with NECA.

8. NSPs’ Annual Planning Reviews

8.1 Background

The options paper proposes an enhancement to the Statement of Opportunities and describes a number of market pressures that would be addressed. These pressures include:

- more explicit consideration of the least-cost alternatives to network investment;
- “deep” connection charges that derive from existing network planning and investment projections;
- the calculation of demand-side management payments based on network planning and investment projections; and
- management of asset stranding risks for NSPs through enhanced planning and consultation processes.

To enhance the Statement of Opportunities, the options paper proposes that:

- distribution NSPs publish an annual statement of network utilisation; and
- longer term opportunities for private sector investment as alternatives to network investment be explicitly identified as part of NSPs annual planning reviews.

Although the options paper indicates that “*a number of pressures point to the advantages of enhancing [the Statement of Opportunities]*”, it is not clear how the proposed amendments will allow these pressures to be fully alleviated and whether these pressures of themselves justify enhancing planning reviews and information disclosure.

In advance of any enhancements to the Statements of Opportunities a clear evaluation of the costs and benefits should be performed. It is not clear that what is proposed will assist significantly in addressing areas of real priority. Whilst enhanced information disclosure has some benefits, the options paper does not consider the potential disadvantages.

8.2 DNSP Annual Statement of Network Utilisation

The publishing of DNSP network utilisation data is not likely to directly address any of the four pressures referred to above. Although it would provide signalling to customers and embedded generators of network utilisation issues, we believe that given the costs of additional disclosure (discussed further below), the incremental benefits achieved on existing market incentives does not justify the publication of network utilisation data. Commercial incentives within the existing regulatory framework already encourage DNSPs to work with generators and customers in assessing augmentation needs. In addition, the publication of this data would not in itself address any potential shortfalls in the planning and investment projections undertaken by the DNSPs nor in the computational methods used to assess the impacts of augmentation options.

8.2.1 Additional disclosure further adds to information provision compliance costs

The Code and other regulatory requirements already result in DNSPs incurring significant compliance costs in meeting, inter alia, network information requests from the jurisdictional regulators. These include the costs of regulatory reporting (separate regulatory accounts), ring fencing of distribution and retail elements of the business, completion of statement of opportunities/annual planning review and provision of information to NEMMCO (eg network capability and electrical data). Increased information provision will further add to already significant compliance costs.

8.2.2 Network utilisation information is commercially sensitive

The publication of an annual statement of utilisation would bring into the public domain information that is commercially sensitive and that could put distributors in an inequitable position with respect to their customers in light of the regulatory price setting process. In addition, under proposals for competitive distribution (ie by-pass) the public disclosure of a DB’s competitive network information would result in a major disadvantage relative to its potential competitors.

It is not clear that the publishing of utilisation data will of itself address the four pressure points referred to in the options paper. For example, it is unlikely that the enhancement of the statement of opportunities will mitigate the risks of stranded assets which are to a large extent the outcome of the commercial dynamics of the market.

8.2.3 Usefulness of Planning Information for Distribution Networks

Unlike transmission networks, planning for distribution networks is subject to greater change as a result of numerous customers and load and generation variability. As a result of the variability of these factors, detailed distribution plans are more likley to change during the year. As such, the usefulness of any annually reported planning information is likely to be impaired. In addition, the risk arises that distribution customers may not fully understand the information and will misinterpret utilisation data. As such, risks would transfer from DBs to customers who are less able to manage these risks. We believe that existing arrangements whereby DBs work closely with large customers and embedded generators in sharing the benefits of enhanced systems efficiencies provides sufficient incentives to work effectively for all parties. We would strongly caution against the provision of utilisation data for distribution networks given the volatility of distribution planning and the significant risk that data will be misunderstood.

8.3 Enhancement of TNSPs Annual Planning Reviews

It is proposed within the options paper that private sector investment is explicitly identified as part of the NSPs' annual planning reviews. Whilst private sector investment can make an important contribution to enhancing the network, we consider that it should not be subject to explicit consideration. We believe that sufficient incentives already exist for NSPs to consider a wide range of options both as a result of market mechanisms as well as through the Code. The Code has a number of provisions which require that augmentation issues be given due consideration as part of the annual planning review. These include the requirement for full consultation procedures (cl 5.6.5(f)), disclosure of the methodology applied in the process, and an evaluation of the costs and benefits of augmentation options and evaluation of any practicable alternatives to augmentation (cl 5.6.5(h)).

8.4 Conclusion

A more robust evaluation of the costs and benefits of enhancing the statements of opportunities is required. We believe that the evaluations to date have not adequately considered the costs associated with the proposed enhancements. We believe that the Code, the regulatory regime, and existing market incentives already provide a number of drivers that facilitate a satisfactory planning process to ensure that issues of network constraint and losses are adequately addressed. We recommend that NECA ensure that a robust and balanced evaluation of any proposed enhancements is undertaken which fully recognises the incremental costs and gives full recognition to existing incentives.

9. Inter-regional Hedging, Firm Access and a Framework for Non-regulated Interconnectors

9.1 Background

It is recognised that this area is arguably the least contentious of the three areas reviewed in the options papers. Whilst we support a number of the initiatives proposed it is important that any options pursued are viewed in the broadest context. A number of proposed arrangements may create more problems than they actually solve.

9.2 Inter-Regional Hedging

The Code provides little guidance on objectives for inter-regional hedging ("IRH"). However, there is strong support amongst market participants for the recycling of settlement surpluses back into the market to enable participants to contract their risks efficiently and encourage inter-state trade. NECA should clarify, inter alia, the objectives in the Code and develop a plan to achieve the objectives.

The original market design assigned the settlement surplus to TNSP to be passed back to consumers through lower Network Charges. Any departure from this must consider carefully the cash flows and demonstrate the economic benefits.

9.3 Link-based inter-regional hedging

NECA suggests that inter-regional hedges have a potentially important role in:

- providing a market based mechanism to coordinate investment and maintenance;
- providing a non-distorting revenue source to help pay for network augmentation and refurbishment (reducing the need for more arbitrary cost recovery vehicles); and
- assisting in overcoming inefficient barriers to trade.

9.3.1 Auction based inter-regional hedge trading and the proposed trials are important steps in market development

We support the roles outlined above and agree with the examination of an auctions based trade in link-based inter-regional hedges. The current auction trial provides a valuable mechanism by which to gain experience in the operations of an auction based hedging facility. NECA should satisfy itself that the outcomes of the trial are clearly measured and subsequently communicated to stakeholders and that sufficient consultation will be allowed for. Link based IRHs are essential to participants for them to minimise their risks and we encourage NECA to review the IRH trial six months after market start.

9.3.2 Inter-regional hedges must be viewed in the context of overall trading arrangements

Inter-regional hedges underwritten by settlement surpluses are an integral part of the overall trading arrangements that will facilitate the development of an effective national market. Assessment of the overall effectiveness of inter-regional hedging must be made in the context of its incremental contribution in light of the impact on other arrangements eg ancillary services. In addition, the prevalence of swaps across regional borders provides an alternative mechanism by which to hedge inter-regional positions. A key NECA objective must be to ensure the creation of the right environment to facilitate efficient development of appropriate market-based instruments.

9.3.3 Hedging mechanisms must reflect the peculiarities of the Australian market

The inter-regional hedging mechanism adopted must be reflective of the unique characteristics of the Australian market. Whilst we note a number of overseas jurisdictions that have successfully introduced a number of forms of tradeable transport rights, the translation of these to our environment must be critically reviewed.

9.4 Firming-up Inter-Regional Hedges

9.4.1 Development of firm inter-regional hedges

We support the principle of the development of firm inter-regional hedges which would cover against inter-regional price differences under a wide range of circumstances provided there will be a practicable solution. A firm hedge would be simpler from the holder's perspective, allow the allocation of certain transmission costs to generators, transfer the risks of transmission failure to those who are best positioned to manage it (ie the TNSPs) as well as provide greater definition of the risks and rewards of the contracting parties. As such, we support the additional work being undertaken by the NEMMCO working group aimed at developing the current proposal into fully firm hedges. However, as NECA has identified many complex issues would arise in developing such arrangements. These include:

- provision, and incorporation into settlements residues of the cost, of ancillary services;
- harmonisation of contractual arrangements with multiple TNSPs;
- underwriting of risks associated with interconnector transmission losses and network failure not able to be underwritten by settlement surpluses; and
- management of involvement of regulated NSPs which are not market participants but who would be crucial in guaranteeing network performance.

In addition to the above, the DBs note that a clear practical solution to the issue of how to make the hedges firm, has not yet been found. Victorian DBs support, in principle, working towards the long-term development of Firm Inter-Regional hedging. However, the costs and benefits must balanced in the development of a model.

9.4.2 Firm inter-regional hedges

The extent to which TNSPs can be exposed to appropriate commercial drivers in relation to the availability of transmission assets without undue damage to their risk profile, is perhaps the key issue to be considered with respect to firm inter-regional hedges. In light of these complexities the development of firm hedge instruments should ensure that it does not create more problems than it solves.

It is expected that the risk management skills required of a TNSP in dealing in financial instruments is outside of the existing competencies and risk profiles of these businesses. A strong incentive exists for a regulated interconnector owner who is forced to take market risk for availability to ascribe an overly conservative rating to the interconnector, insure the unavailability risk with a third party, and pass the costs onto end customers through the regulated tariff. The potential for this sub-optimal scenario should be closely evaluated.

9.5 Intra-regional firm access and negotiation of service levels with TNSPs

9.5.1 System Constraint Compensation

In our 31 March 1998 submission we raised a number of concerns in respect of what generators proposed, namely, *that "firm access is a system by which network service providers are **compelled** to compensate generators when access to the market is constrained*." We would like to emphasise that the significant issue raised in our previous submission that the level of service provided to the generators for network access should be commensurate to the level of charges paid.

9.5.2 Quantification of TNSP Service Levels

The Code allows (cl5.5) generators to negotiate firm access arrangements with network service providers and we fully support the development of incentive mechanisms for TNSPs to enhance firm access arrangements. However, in advance of the negotiation of firm access arrangements a clear definition and quantification of the current "base level" of service is required. This will allow the establishment of a clear cost/benefit starting point for the evaluation of firm access proposals. The provision of negotiated incentives will drive TNSPs to improve performance to maximise market efficiency.

However, the Code should not be prescriptive in this area and should allow individual generators to negotiate with their local TNSP. Because of the geographic and technical differences between generators, these arrangements should rightly be the subject of commercial negotiation, not a centrally imposed outcome.

The Victorian DBs support the need for minimum standards to be contained within the Code but not target standards. These should be part of an incentive mechanism which is agreed with the Regulator and must be consistent with the pricing regime pertaining at the time.

9.6 Non-Regulated Interconnectors

9.6.1 Mandating that all new interconnectors be non-regulated will not accommodate current market constraints and introduces excessive risk to TNSPs

The code already allows for non-regulated interconnectors. We noted in our initial submission that some industry participants are proposing at industry forums three policies:

- that all new interconnectors be non-regulated;
- that transmission companies face greater incentives to make interconnectors available; and
- that eventually all existing interconnectors become non-regulated.

We still maintain that non-regulated interconnectors are a good model for some interconnectors in the medium to long term, but the code should not mandate now that all new interconnectors be non-regulated. We would like to reiterate the key arguments put forward in our previous submission as to why regulated interconnectors must be allowed to continue to proceed:

- mandating that all new interconnectors be non-regulated will only exacerbate top end problems in the generation market - if regulated interconnectors or interconnector upgrades are installed, the capacity constraints and gaming opportunities at the top end of the market will be eased significantly; and
- the establishment of only non-regulated interconnectors in the short to medium term is likely to significantly increase risks faced by TNSPs to inappropriate levels if regulated interconnectors are not encouraged.

9.6.2 Interconnector Development Framework

We support, in principal, the introduction of non-regulated interconnectors but only when the circumstances are appropriate and not to the exclusion of regulated interconnectors. It is likely that non-regulated interconnectors will be the exception and that regulated interconnectors will be the norm. This is due to the nature of the investment, that is, high up front capital costs with the prospect of gaining adequate incomes only once the interconnector nears full capacity utilisation. For this reason, the viability of non-regulated interconnectors in many circumstances is questionable.

We are very concerned that NEMMCO and NECA will not progress the interconnectors that are actually needed and recommend that NECA documents, in the Code, the principles which reflect the current transmission model. We also recommend that the rules/methods adopted do not exclude, as a matter of course, all regulated interconnectors and would see that a review of the planning methodology should be carried out as a matter of urgency.

In conjunction with this, a framework should be developed for non-regulated interconnectors which accommodate issues such as the provision of a level playing field, abuse of market power, and spot market participation.

9.7 Conclusion

The Victorian DBs believe that clear objectives should be defined and agreed for these issues so that a clear direction is established. Against this the recommendations of the Victorian DBs which are contained throughout this Section, can be viewed in the appropriate context.