61 Mary Street
Brisbane QLD 4000
PO Box 107 Albert Street BC
Brisbane QLD 4002
www.ergon.com.au
Telephone 07 3228 8222
Facsimile 07 3228 8118

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Australian Energy Market Commission
PO Box H166
AUSTRALIA SQUARE NSW 1215

submissions@aemc.gov.au

Dear Sir/Madam

AUSTRALIAN ENERGY MARKET COMMISSION
CONSULTATION ON "REVIEW OF THE ELECTRICITY TRANSMISSION REVENUE AND PRICING RULES – Transmission Pricing: Issues Paper"

Ergon Energy is pleased to make this submission, which is available for publication, in its capacity as an electricity Distribution Network Service Provider in Queensland.

We have reviewed the AEMC's Issues Paper entitled "Review of the Electricity Transmission Revenue and Pricing Rules – Transmission Pricing: Issues Paper" (the Paper). Ergon Energy recognises that the timing of the Paper has been driven by provisions of the NEL and as such has not been completely within the control of the AEMC. Nevertheless, Ergon Energy notes that the MCE is undertaking parallel processes addressing similar issues with respect to regulation of the energy sector and Ergon Energy has concerns that the AEMC process could potentially result in regulatory changes for electricity transmission that are incompatible with eventual MCE recommendations.

In preparing this response to the Paper and the AEMC' s previous Revenue Requirements Issues Paper, Ergon Energy has attempted to establish a consistent theme, namely, that the Rules should not seek to impose unnecessary prescription but rather should establish high level principles and provide the AER with discretion in undertaking its task. Further, an incentive based propose/respond model should be adopted whereby network service providers are able to submit a preferred approach consistent with the Rules and reflecting their individual commercial and operating issues. This model should include stronger incentives whereby network service providers are given property rights to a greater percentage (at least 50%) of the benefits accruing from efficiency improvements attributable to their actions. The AER should only be able to reject the proposal where it is inconsistent with the Rules or where parameter values are outside a reasonable range. The ability of the AER to reject network service providers' proposals means that it is essential that network service providers have access to merits review.

This submission follows the structure of the Paper and reproduces and responds to those questions that Ergon Energy has a specific view on. These are detailed below.

Chapter 2 – Requirement for Regulation

1. Should transmission prices be regulated and why?

Ergon Energy would first like to reiterate its views expressed in its' submission on the AEMC Revenue Requirements Issues Paper, namely that it is critical that the scope of regulation is limited to circumstances where there is a demonstrated need with Rules setting out a test and a process where network services providers can test the continued application of regulation to assets or services. Further, the Rules should specify the form of regulation and the form should be limited to a building block based revenue cap, price cap or hybrid with network service providers able to propose the form of control they believe best addresses their particular circumstances. Finally, the aim should be to ensure a high degree of consistency between the regulation of electricity transmission and distribution service providers.

Assuming that regulation is limited to those assets or services where there is a demonstrated need, and that network services providers have flexibility to propose the form of control (within limits), Ergon Energy believe that allowance for some form of regulation of transmission prices should be made. For example, under Ergon Energy's preferred propose respond model, it would be open for a TNSP to propose a price cap form of control which in turn would require some clarification of the prices that are the subject of the control.

2. If regulation is required what form should this take? For example, should it be less prescriptive and involve greater transparency or be more prescriptive?

The flexibility inherent in Ergon Energy's preferred incentive based propose respond model means that the Rules will need to be limited to providing high level guidance with respect to regulation of transmission prices. This will ensure that the AER is given sufficient flexibility to be able to tailor requirements to a particular service providers circumstances. Clearly, this increased level of discretion will need to be supported by high levels of regulatory transparency together with service providers being able to access appropriate merits review processes.

3. What role, if any, should the AER have in determining the nature and form of price regulation?

Under Ergon Energy's preferred propose respond model, service providers would develop detailed proposals for submission to the AER including details with respect to pricing that is consistent with the proposed form of price control. This in turn requires that the AER has sufficient flexibility to be able to assess each proposal on its merits given the particular circumstances faced by each service provider and the form of control proposed.

Chapter 3 – Context and Objectives for the Review

4. Bearing in mind the NEM objective, should economic efficiency of the Rules be the focus or should it also have regard to the distributional consequences of Rule changes?

Ergon Energy notes that the current NEM objective includes reference to the long term interests of customers and as such, it may be appropriate to include a clear economic efficiency objective as part of the Rules. Ergon Energy considers that distributional impacts are important and it is likely that jurisdictions will have concern over the impact of possible price shocks. Historically, this has been dealt with at a distribution level where jurisdictional regulators have placed side constraints on prices limiting the maximum increase allowed in any given period. Ergon Energy believes this remains the best approach with the AER required to take account of the impact of any jurisdictional directions in this regard. Further, it would be open to service providers to propose a mechanism to smooth the impact of any change to pricing arrangements with the AER able to assess such a proposal on its merits. For example, Ergon Energy generally supports the use of side constraints to minimise the impact of price movements, however, Ergon Energy believes that such side constraints should be symmetrical, that is, should apply to both price increases and decreases and that there should be no negative impact on the network service providers revenue recovery over time.

5. **If the NEM objective should have regard to distributional consequences of Rules changes, how should these be taken into account?**

Ergon Energy is of the view that the NEM objective should not be modified to include an explicit requirement for regard to be given to distributional impacts.

Chapter 4 – Current Transmission Pricing Regime

6. **Is the allocation of network costs between the connection and shared network categories in the Rules broadly appropriate? If not, how could it be improved?**

Ergon Energy's experience as a DNSP is that the cost allocation between connection and shared network categories is reasonable and as such, Ergon Energy has no particular suggestions for improvement.

7. **Should a common service charge be maintained or should these costs be incorporated into another charge? If not, how should common service costs be allocated or incorporated into other charges?**

Ergon Energy is of the view that the over arching aim of any charging structure should be to ensure the efficiency of the structure with a principal focus on long term dynamic efficiency impacts (rather than short term allocative efficiency improvements) due to the critical role dynamic efficiency plays in underpinning long term growth and increased economic welfare.

The initial question is whether the cost drivers for common costs are the same as any other category of costs and therefore such categories could be combined.

In general, Ergon Energy believes that it is appropriate to recognise a category of costs related to the provision of common services, however, the allocation of such costs to particular connection points using historic consumption at that connection point from two years prior can lead to significant volatility in the magnitude of particular connection point charges where there is significant change in either load connected to that point or in the supporting transmission network. This can be a particular problem in Queensland where there is a combination of rapid growth and associated changes in both transmission and distribution infrastructure. As such, Ergon Energy believes that a more appropriate basis for allocating common service charges would be to allocate the common service charge for a TNSP across the forecast energy with the resulting charge recovered as a single charge against each connection point. The subsequent allocation of this charge to users at a particular connection point is the subject of the pricing structure discussed below.

8. **Should generator and MNSP use of system charges remain a matter for negotiation with the TNSP or should they be prescribed in the Rules?**

Ergon Energy believes that where possible system charges should be subject of negotiation guided by high level principles within the Rules rather than on the basis of highly prescriptive Rules. The negotiation framework would clearly need to be supported by appropriate dispute resolution/arbitration provisions.

9. If a modified CRNP usage charge is to remain an option:

- **should the Rules prescribe the criteria for the AER to accept implementation of modified CRNP?; and**
- **should any network customer (rather than just the TNSP) be able to request that the modified CRNP methodology be implemented?**

Ergon Energy believes that it is essential to continue to allow a modified CRNP approach given the limitations of the standard CRNP model as discussed in the Issues Paper. Consistent with Ergon Energy's preferred propose respond model, it is considered that the Rules should be limited to establishing overarching principles that provide high level guidance to the AER as to the basis for assessing whether to accept or reject a TNSP's modified CRNP proposal. TNSP's would in turn have access to suitable merits review processes where they considered that a proposal had been rejected on a basis inconsistent with the principles outlined in the Rules.

Ergon Energy considers that only network service providers should be able to propose implementation of a modified CRNP. Allowing third parties to do so could result in potentially multiple alternative proposals that would be mutually incompatible. It is considered that the views of network customers are best addressed through a regulatory framework that provides appropriate incentives to network service providers to identify service elements customers' value and to develop regulatory proposals aimed at delivering those services in the most efficient manner possible.

10. How well do the CRNP and modified CRNP methodologies accord with efficient pricing principles? Could simpler approaches be applied to produce similar outcomes?

Ergon Energy acknowledges that the CRNP methodology relies on relatively arbitrary allocation bases to ensure full allocation of all costs. As noted in the Paper, the modified CRNP offers the potential to address some of the unintended consequences of the standard CRNP approach. For example, as discussed above, the allocation of common service costs to particular connection points using historic consumption at that connection point can lead to significant volatility in the magnitude of particular connection point charges where there is material change in either load connected to that point or in the supporting transmission network. This can be a particular problem in Queensland where there is a combination of rapid growth and associated changes in both transmission and distribution infrastructure.

As such, Ergon Energy believes that a more appropriate basis for allocating common service charges would be to allocate the common service charge for a TNSP across the forecast energy with the resulting charge recovered as a single charge against each connection point. The subsequent allocation of this charge to users at a particular connection point (and the mitigation of unintended negative impacts) is the subject of the pricing structure discussed below.

11. If the CRNP and/or modified CRNP methodologies were to be retained are the descriptions of the methodologies in the Rules sufficiently detailed and clear? If not, how could they be clarified?

Ergon Energy considers that the critical issue is to ensure that the Rules are sufficiently flexible to allow the AER the discretion to accept alternative cost allocation proposals from network service providers where such proposals are consistent with high level principles focused on economic efficiency outlined in the Rules. That is, Ergon Energy believes that retaining the current description of the methodologies within the Rules is sensible provided doing so does not preclude TNSP's proposing alternative arrangements consistent with appropriate overarching guiding principles.

12. Is it appropriate to provide scope for TUoS discounting in the Rules?

13. If so, could the existing arrangements be refined and how?

Ergon Energy wishes to address questions 12 and 13 together. Ergon Energy believes that the continued provision for TUoS discounts within the Rules is a key element in underpinning economic growth through allowing major energy users to gain competitive energy costs subject to the constraint that they at least cover the incremental cost associated with their connection.

However, it is critical that the provision of such discounts is only allowed where it is economically efficient (so that prudent discounts should be allowed wherever the TNSP or the dispute resolution body reasonably apprehends that the discount is necessary to attract the load to the network) and that TNSPs and DNSPs are not left financially disadvantaged as a result of any such discount. Ergon Energy believes that the current arrangements may excessively restrict customers ability to access discounts where the test is based on inefficient bypass rather than a minimum test based on covering incremental cost (that is, ensuring no customer is worse off) and with the aim of ensuring a contribution (albeit small) towards common costs.

TNSPs also need to have longer term certainty in not being disadvantaged from discounting – so that they do not feel exposed to offering longer term discounts from network charges that at least recover estimated long run incremental costs at the time that they were negotiated.

Further, to the extent that TNSPs continue to be subject to revenue caps, they may not have sufficient incentive to negotiate TUoS discounts even where such a discount would be efficient. As such, it is considered that the Rules should provide a dispute resolution mechanism whereby customers seeking a discount are able to approach the AER in circumstances where commercial negotiations with the TNSP fail to deliver a satisfactory outcome.

14. Is it appropriate to prescribe arrangements for TUoS rebates in the Rules? If so, could the existing arrangements be refined and how?

15. Do the current pricing arrangements appropriately cover alternatives which contribute to the avoidance or postponement of transmission augmentation?

16. Should TUoS rebates also apply to generators connected to the transmission network, DSM or other non-electricity options? Does this depend on whether generators generally pay shared transmission costs?

Ergon Energy wishes to address questions 14 to 16 together. Ergon Energy considers that it is appropriate to continue to provide guidance within the Rules for the treatment of TUoS rebates rather than simply relying on connection agreement negotiations to resolve the issue as the guidance provided by the Rules is considered to reduce the scope for disputes and to reduce network service provider revenue risk.

However, it is important that the Rules are not so prescriptive as to limit the application of rebates as doing so will result in the removal of an incentive for efficiency enhancing behaviour. That is, network service providers should be given the flexibility to negotiate rebates with any customer (and the AER have the discretion to approve such rebates) where it can be shown that the action of the customer will delay or avoid network augmentation, or otherwise reduce network system costs compared to the world without the action of that customer (that is, will lead to an incremental saving).

Chapter 5 – Efficiency and Transmission Pricing – Key Concepts

17. Should transmission pricing arrangements principally seek to promote efficiency in the short or long run?

Ergon Energy considers that it is critical that pricing arrangements seek to promote long run efficiency as this is a key factor in ensuring that consumption decisions are made with full information of long run implications. Further, the fact that the NEM has now been operating for some 7 years suggests that the majority of the easy productive and allocative efficiency gains will already have been captured. Nevertheless, an appropriate pricing structure should not focus purely on long run efficiency but should also give appropriate weight to short term efficiency improvements.

18. If transmission pricing arrangements should consider both the short and long run, what approach should the Commission take to determine the appropriate balance between these aims?

Ergon Energy considers that the overarching regulatory principle should be that transmission pricing should seek to maximise efficiency in the broadest sense with service providers given the opportunity to propose an appropriate pricing structure consistent with the principles. For example, through the development of appropriate multipart pricing arrangements. The AER should in turn be given the discretion to accept a proposal consistent with the principles and reflecting the particular operating characteristics of the service provider.

Chapter 6 – Relevant NEM Context

19. To what extent are existing signals from other aspects of the NEM arrangements (or requirements from regulatory settings outside the NEM) sufficient to promote efficient behaviour by actual and potential consumers and producers of electricity in the short and long run?

Ergon Energy notes that even for large industrial customers connected directly to the transmission network, TUoS charges are unlikely to exceed 20% of the total cost of delivered electricity and will be significantly less for customers connected to distribution networks. Further, under an efficient multi part tariff structure aimed at providing a mix of short and long term efficiency signals, the proportion of the total energy cost available to act as a signal is likely to be very low. As such, signals from other aspects of the NEM arrangements (such as the non-firm access discussed in the Paper), are likely to have a more significant impact than transmission pricing.

20. Given current distribution network pricing arrangements, is it appropriate to prescribe transmission pricing structures in the Rules?

21. If so, should prescription be limited to prices for particular network users?

Ergon Energy wishes to address questions 20 and 21 together. As noted above, Ergon Energy considers that the Rules should be limited to providing overarching principles to guide the development of pricing structures by network service providers. That is, network service providers would propose a pricing structure to the AER that would need to be consistent with the overarching principles contained in the Rules. As such, the Rules would not need to prescribe transmission pricing structures per se. At a framework level, Ergon Energy believes that it would be appropriate, where possible, for both transmission and distribution network service providers to face the same Rules with respect to pricing. However, it is noted that the high level of interconnection between TNSP networks may suggest the need for increased standardisation compared to DNSPs.

Chapter 7 – Allocation of Regulated Revenue Across Transmission Users

22. Should NEM connection charges continue to be based on a shallow connection approach or should a deep connection approach be adopted?

23. If a shallow connection approach is broadly to be maintained, are there any circumstances where connecting parties should pay for up or downstream upgrades to the shared network?

24. If a deep connection approach is to be adopted in the NEM, how should it be formulated?

25. Is a deep connection approach compatible with the open access transmission regime of the NEM (which is not a subject of the present Review)? If so, how should potential "free-rider" effects be managed?

Ergon Energy would like to address questions 22 to 25 together. Ergon Energy considers that the key issue in moving from shallow connection charge basis to a deep connection charge basis is the difficulty of matching the property rights of the customer to the charging basis. That is, deep connection charging is not compatible with the non-firm open access arrangements of the NEM. Ensuring the enhanced congestion and locational signals possible under a deep connection charging basis do not result in unwanted disincentives for investment requires that enhanced property rights are developed.

26. Do signals from the regional pricing structure of the NEM, non-firm generator access and transmission investment arrangements provide efficient locational and operational signals to generators, loads and competing sources of energy supply?

As noted in question 19 above, transmission charges represent a relatively low proportion of the total delivered cost of electricity for most customers. While transmission charges can still have some locational signalling role, it is likely that this role will be better addressed by other mechanisms such as those outlined in the Paper.

27. Are there reasons why generators should make some contribution to shared network costs? If so, what approach should be used to determine the share of shared network costs should be paid by generators?

Ergon Energy considers that there is potentially significant locational signalling benefits from generators making some contribution to shared network costs. One difficulty associated with implementing such a system is that it is aimed at in signalling future investment. Given that the vast majority of generation capacity is already installed (that is, the investment is sunk), it cannot respond to enhanced locational signals but rather will simply face the possibility of a material change in relative competitiveness which may raise equity issues. As such, the implementation of generator contributions to shared network costs is desirable but requires significant analysis to assess the likely benefits and costs and to identify the optimal proportion of shared costs that should be borne by generators.

28. Is the current shared network charging regime the best approach for achieving the NEM objective? If not, what improvements could be made?

29. Are there arrangements operating in other jurisdictions for the recovery of shared network costs that would be more appropriate for the NEM? If so, which jurisdictions and which aspects of their arrangements would be appropriate for the NEM?

Ergon Energy wishes to address questions 28 and 29 together. Ergon Energy considers that the Rules should be limited to outlining the overarching principles to be incorporated into the shared network charging regime developed by the network service provider. This requires that the AER have sufficient discretion to approve alternative charging arrangements where they can be shown to satisfy the principles. The overarching consideration from a network service provider's perspective is that an alternative to current arrangements should only be entered into where it can be shown to convey net benefits.

As acknowledged in the Paper, in many ways the NEM is still relatively undeveloped, a characteristic particularly apparent in Queensland where significant expansion and enhancement has been mooted for the future to cope with major forecast growth. As such, principles that continue to allow use of a CRNP or modified CRNP approach which is consistent with underlying network planning tools is likely to be preferred in the short to medium term with a move to a pricing structure providing pricing signals based on at least a component of LRMC is likely to be increasingly desirable as networks mature. However, network service providers are likely to be in the best position (in conjunction with the AER) to determine when such a change can be most cost effectively and efficiently introduced.

30. How much discretion should TNSPs have to discount charges?

Network service providers should be given broad discretion to negotiate discounted charges rather than attempting to prescribe such arrangements through the development of detailed Rules (other than the need for the TNSP to demonstrate in its reasonable opinion that the discount was necessary to attract the load to the network for whatever reason and that incremental cost was recovered). This is consistent with the commercial negotiations that a service provider will routinely undertake with major customers and should be supported by a dispute resolution mechanism whereby customers seeking a discount are able to approach the AER in circumstances where commercial negotiations with the TNSP fail to deliver a satisfactory outcome. This is especially important if TNSPs continue to be regulated under revenue caps.

31. Should TNSPs be entitled to recover the cost of discounts from other loads?

Ergon Energy considers that it is essential that efficient discounts do not leave the network service provider financially disadvantaged, that is, to the extent that a discount would result in a reduction in the TNSPs returns below that provided for by the regulator, then that shortfall should be allowed to be recovered form other loads. However, it is noted that the majority of such discount applications are likely to be with respect to new network connections and as such, given that at a minimum charges will be required to cover the incremental cost of the connection, there should not be any need to "recover" discounted revenue from other customers relative to a situation where connection would not otherwise occur. That is, no other customers price will need to increase to compensate for the discount offered to the new connection.

32. Should any conditions for recovering the cost of discounts from other customers be prescribed in the Rules or left to the AER to determine? If so, what should be the general content of these Rules or AER discretions?

Ergon Energy considers that the Rules should specify the over arching principle that only efficient discounts should be allowed and that at a minimum, charges should recover the incremental cost of the connection. Ergon considers that the scope of discounting should be increased to where it is prudent – not limited to where bypass would otherwise occur. This would extent to where such discounts are necessarily to attract significant load to the NEM that is the subject of international competition.

33. Should avoided TUoS rebates be retained in the Rules or left for negotiation between the DNSP and connected party?

Ergon Energy considers that the treatment of TUoS rebates should be consistent with TUoS discounts. That is, such discounts should be the subject of negotiations between the DNSP and the connected party with the Rules establishing high level principles to guide such negotiation and with access to dispute resolution by the AER where an agreement cannot be reached.

34. Is the appropriateness of TUoS rebates contingent on whether generators pay shared use of system charges?

35. If TUoS rebates are retained, what charges should they comprise?

Ergon Energy wishes to address questions 34 and 35 together. Ergon Energy considers that in a market exhibiting strong growth such as the NEM with associated high investment requirements, TUoS rebates need not be contingent on generators paying shared use of system charges. Rather, the issue is one of a cost benefit analysis of the world with and without the embedded generator – that is, savings on future network expansion and any other incremental cost savings.

Chapter 8 – Structure of Prices

36. To what extent is it necessary or worthwhile to prescribe transmission pricing structures in the Rules in order to promote the NEM objective?

37. Would it be appropriate to provide guidance to TNSPs on what pricing should achieve instead of prescribing the structure? If prescription is required, which charges should have price structures prescribed in most detail?

38. Should the degree of pricing structure prescription vary depending on the relevant class of network user paying the charge? If so, how could this be implemented?

39. How much discretion over charging structures should be left to the TNSP and the AER?

Ergon Energy wishes to address questions 36 to 39 together. Consistent with its views on the regulatory framework, Ergon Energy considers that the Rules should not prescribe pricing structures but rather should only provide high level principles with network service providers to propose to the AER pricing approaches consistent with the Rules. This general approach should be followed irrespective of the class of network user paying the bill. This approach requires that both the TNSP and the AER are given significant discretion over the shape of the charging structure.

Chapter 9 – Pricing of Non-prescribed Services

40. Are the negotiation provisions in the Rules regarding prices for non-prescribed services appropriate? What difficulties (if any) have been experienced?

41. Should Rules provide criteria in relation to pricing outcomes for non-prescribed services?

Ergon Energy wishes to address questions 40 and 41 together. Ergon Energy considers that the current arrangements based on a "negotiate-arbitrate" approach to establishing prices for non-prescribed services are appropriate. The Rules do not need to provide criteria in relation to pricing outcomes for contestable customers, although it may be appropriate for pricing of non-contestable but non-prescribed services to be required to satisfy high level pricing principles..

42. Should a price monitoring regime be considered for non-prescribed services?

43. If so, what criteria would be appropriate? Would these be the same for all non-prescribed services?

Ergon Energy wishes to address questions 42 and 43 together. Ergon Energy does not believe that a price monitoring regime for non-prescribed services needs to be prescribed. The current Rules provide scope for such an approach to be adopted by the AER, that is identification of contestable transmission services and application of a more light handed form of regulation. The critical issue is to ensure that the principle of minimising regulatory intervention is enshrined in the Rules with regulation only imposed where it can be clearly shown to be justified on cost benefit grounds.

44. Are the current dispute resolution provisions in Chapter 8 of the Rules appropriate for disputes over pricing of non-prescribed services? What (if any) alternative dispute resolution processes may be appropriate?

Ergon Energy considers that the current dispute resolution processes are appropriate.

Chapter 10 – Inter-regional Issues

45. Could the current provisions in the Rules regarding inter-regional TUoS payments be improved? If so, how?

46. What are the impediments, if any, to reaching interregional agreements?

47. Should the Rules provide criteria for determining the 'extent of use of a network'? If so, what criteria would be appropriate?

48. Is there a need for greater clarity in the Rules on the treatment of the negotiated charge paid by the importing region to the exporting region for the purposes of determining annual aggregate revenue requirement of a TNSP?

Ergon Energy wishes to address questions 45 to 48 together. Ergon Energy considers that the current arrangements for inter-regional TUoS payments are less than ideal and should be reviewed with the aim of ensuring incentives are established consistent with those for transmission. Overall, it is considered that the same overarching principles can be applied to this issue as to the connection of any other load. That is, that such interconnection should not result in existing customers being worse off and at a minimum, importing regions should at last cover the incremental costs they impose on the network.

49. Would it be appropriate to extend the expiry date of clause 3.6.5(a)(5)(ii) from 1 July 2006 to 31 December 2006 to coincide with the conclusion of the Commission's review?

Ergon Energy believes it would be reasonable to extend the expiry date of clause 3.6.5(a)(5)(ii) from 1 July 2006 to 31 December 2006 to coincide with the conclusion of the Commission's review.

50. Do the current, or alternative arrangements provide TNSPs with adequate incentives to invest in assets that facilitate electricity flows between adjacent jurisdictions? If not what improvements could be made?

51. Should the negotiations of inter-regional payments be between TNSPs rather than jurisdictional governments?

52. Should incentives/penalties be in place in the Rules to ensure that an inter-regional agreement is in place?

53. Should the provisions of clause 3.6.5 be replaced by a modified approach to TUoS pricing more generally?

Ergon Energy wishes to address questions 50 to 53 together. Ergon Energy considers that there are problems with current arrangements. For example, with the interaction between regulated and market interconnectors where the possibility of additional (non-commercial) regulated interconnectors is likely to make investment in market interconnectors less attractive. However, this is a complex issue and Ergon Energy believes that it should be the subject of a more comprehensive review as mooted by the ACCC.

If you have any questions on this and related matters, please contact our Manager Regulation Networks, Tony Pfeiffer (07 3228 7711).

Yours faithfully

for

Tony Pfeiffer
Manager Regulation, Networks

Cc: Mr Alan Millis
Deputy Director General
Department of Energy
P O Box 15216
City East Qld 4002