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1 February 2008

Mr Chris Pattas
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Dear Mr Pattas

Issues Paper: Guidelines, models and schemes for electricity distribution network service providers

Ergon Energy Corporation Limited (Ergon Energy) appreciates the opportunity provided by the Australian Energy Regulatory (AER) to comment on the development of the guidelines, schemes and models to best support the transition to a nationally consistent framework for economic regulation of electricity distribution networks.

The attached submission represents Ergon Energy's response to the AER's Issues Paper.

Ergon Energy looks forward to providing continued assistance to the AER in the development of a national regulatory framework for energy.

Yours sincerely

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Ergon Energy Corporation Limited

Guidelines, Models and Schemes for Electricity Distribution Network Service Providers

Australian Energy Regulator

1 February 2008

Guidelines, Models and Schemes for Electricity Distribution Network Service Providers – Issues Paper

Australian Energy Regulator

1 February 2008

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

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in its capacity as a Distribution Network Service Provider in Queensland.

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1 Overview

Ergon Energy Corporation Limited (Ergon Energy) welcomes the opportunity to provide comment to the Australian Energy Regulator (AER) on its consultation *"Guidelines, models and schemes for electricity distribution network service providers (November 2007)"* (Issues Paper). This submission is provided by Ergon Energy, in its capacity as an electricity distribution network service provider (DNSP) in Queensland.

Ergon Energy would welcome the opportunity to discuss this submission or provide further detail regarding the issues that it has raised should the AER require.

2 Approach

The Issues Paper identified a number of possible parallels between the National Electricity Rules (Rules) provisions supporting the regulation of transmission network services providers (TNSPs) and those which may be applied to the regulation of DNSPs.

Ergon Energy believes that there are a number of key differences that exist between TNSPs and DNSPs, and individual DNSPs, within and across jurisdictions, that serve to influence the extent to which the same, or similar, regulatory approaches should be adopted. These differences are largely reflective of sector-specific issues, variations in operating environments and the content of existing jurisdictional regulatory regimes.

This implies that the AER should not attempt to develop guidelines and models that are generic across network service providers but rather, the AER should ensure that the framework is flexible enough to recognise:

- An individual DNSP's circumstances as influenced by issues such as service classification, the form of price control and method of cost allocation;
- Modifications that are required as a consequence of transitional arrangements, including for those matters identified in Chapter 11 of the Rules; and
- The financial implications for a DNSP which may arise in the course of transitioning from prior regulatory regimes to those regulated by the AER.

3 Post Tax Revenue Model

Basis and policy objectives

The AER seeks comment on whether other rule provisions exist that are relevant to developing the PTRM for electricity distribution. Comments are also invited on whether the provisions mentioned here may require a different approach or have different meaning in the context of distribution and transmission regulation.

The transitional arrangements in Chapter 11 of the Rules will be relevant to the AER's development of the Post Tax Revenue Model (PTRM). For the Queensland DNSPs, these include the following clauses:

- 11.16.3 – Treatment of the regulatory asset base (RAB);
- 11.16.9 – Cost pass throughs; and
- 11.16.10 – Capital Contributions Policy.

With regard to specific provisions in Chapter 6 of the Rules, Ergon Energy suggests that the clarification of the following would assist in development of both the PTRM and Roll-Forward Model (RFM):

- **Indexation/inflation**

  Clarification is required as to the AER's intended interpretation of inflation and indexation as referred to in Chapter 6. In particular:

  - 6.4.2(b)(1) (content of the PTRM) – requires that the PTRM include a method that the AER determines is likely to result in the best estimates of expected inflation;
  - 6.4.3(a)(1) (building block approach) – requires that the annual revenue requirement for a DNSP for each regulatory year of a regulatory control period must be determined using a building block approach, including a building block for indexation of the RAB. In this regards, clause 6.4.3(b)(1)(ii) requires the building block comprise a negative adjustment equal to the amount referred to in S6.2.3(c)(4) (roll-forward of RAB within regulatory control period) which requires the maintenance of the real value of the RAB by adjusting for inflation;
  - 6.5.1(e)(3) (content of the RFM) requires that in the roll-forward of the RAB from the immediately preceding regulatory control period to the beginning of the first regulatory control year of a subsequent regulatory control period, the value of the first mentioned RAB must be adjusted for actual inflation, consistently with the method used for indexation applied for the preceding regulatory control period.

  Ergon Energy seeks clarification regarding the AER's intending interpretation of inflation and indexation, including whether actual inflation can be interpreted to mean inflation as it relates to the use of actual capital expenditure (capex) and actual deprecation in roll-forward calculations.

- **Estimated cost of corporate tax**

  For the purposes of calculating the estimated cost of corporate income tax for a DNSP, clause 6.5.3(2) states the estimate must take into account the estimated depreciation for that regulatory year for tax purposes, for a benchmark efficient DNSP, of assets where the value of those assets is included in the regulatory asset base for the relevant distribution system for that regulatory year.

  Clarification is sought that this can be interpreted to mean that, for the purposes of calculating the estimated cost of corporate income tax, the taxation value of assets should be used in estimated deprecation for tax purposes.

Consistency between the PTRM for transmission and distribution regulation

The AER seeks comment on whether the PTRM developed for electricity transmission provides a suitable basis for distribution regulation. If not, what particular features or aspects of the PTRM need to be amended?

While Ergon Energy considers that the PTRM developed for transmission provides a reasonable basis for distribution regulation, regard must be had for existing regulatory arrangements (i.e. possible variances in the 'starting point' for regulation) and operating environments.

For example, the PTRM requires a DNSP's capex on an 'incurred' and 'as commissioned' basis. Ergon Energy queries whether an 'as commissioned' approach is appropriate given the large number of small projects undertaken by a DNSP, relative to a TNSP.

Capital Contributions

The AER seeks comment on how the PTRM could be modified to recognise the treatment of capital contributions, or whether it may be more suitable to deal with this during the reset processes.

Ergon Energy suggests this issue is more appropriately dealt with during the regulatory reset process.

Cash-flow timing issues

Do the PTRM's current timing assumptions result in any systematic bias in favour of service providers? If so, is there merit in considering modifications to the PTRM to remove this bias, for example, in the form of present value adjustments discussed here? To what extent would these adjustments increase the administrative burden and complexity of the

Ergon Energy reiterates that the (negative) financial implications for a DNSP which will arise in the course of transitioning from prior regulatory regimes to those regulated by the AER must be considered in development of the Guidelines and models discussed herein.

Forms of Control

Stakeholders are invited to comment on the benefit of incorporating indicative X factor calculations in the PTRM under common forms of price control, namely revenue caps (as per the existing PTRM), weight average price caps, and revenue yields.

Ergon Energy does not believe it is practical for the AER to incorporate indicative X factor calculations in the PTRM under a weighted average price form of control as this will necessarily be influenced by the tariffs, service classifications and volumes that will form part of the DNSP's pricing review proposal. Given their complexity, no benefit would be delivered in these circumstances.

Linkages with information requirements

Stakeholders are invited to comment on other likely information requirements associated with the PTRM.

Ergon Energy has no specific comment on this issue.

4 Roll-Forward Model

Basis and policy objectives

> The AER seeks comment on whether other rule provisions exist that are relevant to developing the RFM for electricity distribution.
>
> Comments are also invited on whether the provisions mentioned here may require a different approach or have different meaning on the context of distribution and transmission regulation.

Ergon Energy refers to the specific comments detailed in Section 3 of this submission regarding those areas where clarification as to the AER's intended interpretation would assist in the development of the RFM.

Consistency between the RFM for transmission and distribution regulation

> Stakeholders are invited to comment whether there are any impediments to using the AER's transmission RFM as a basis for the distribution model.

Ergon Energy refers to the general comments provided in Section 2 of this submission.

Distribution specific issues

> The AER invites comments on whether the adoption of existing models is appropriate and whether there are specific issues regarding these models, and current jurisdictional revenue determinations, that the AER needs to consider in performing its first round of roll-forward calculations in each jurisdiction.

Ergon Energy refers to the general comments provided in Sections 2 and 3 of this submission.

5 Cost Allocation Guidelines

Linkages to other guidelines

Written comments from interested parties are sought on the following:

- Given the similarity between the respective Rules provisions for transmission and distribution, to what extent should the AER adopt a similar approach to cost allocation between distribution and transmission businesses?
- Are the proposed general principles discussed above for the provision of information for cost allocation in the distribution sector appropriate?
- Should any other general principles and or requirements be reflected in the distribution cost allocation guidelines?

Ergon Energy refers to the general comments provided in Section 2 of this submission.

Ergon Energy also notes that the timeframes for developing and approving the AER's Cost Allocation Guidelines and the DNSP's Cost Allocation Method (CAM) may introduce a degree of uncertainty into the preparation of Ergon Energy's Regulatory Proposal.

The Rules provides that:

• Amended Rules commence	1 January 2008
• AER publishes Cost Allocation Guideline	*by* 30 June 2008
• Ergon Energy to submit CAM	*by* 31 December 2008
• Ergon Energy to submit Regulatory Proposal	*by* 29 May 2009
• AER to approve CAM	*within* 6 months of receipt (i.e. no later than 30 June 2009)

As a consequence, the Regulatory Proposal will be prepared on the basis of expenditure that is allocation in accordance with the CAM, although Ergon Energy may be required to submit its Regulatory Proposal prior to the AER approving the CAM.

Ergon Energy will seek to work with the AER to mitigate the uncertainties and risks created by these timing issues.

6 Efficiency Benefit Sharing Scheme

By way of general comment, Ergon Energy encourages the AER to proceed cautiously with the implementation of new schemes. This is because, not only are DNSPs making significant business adjustments in applying the new Rules in preparing their Regulatory Proposals (forecasts, allocations, applying new principles and criteria), they are also having to balance the potential risks and rewards of new schemes. Overall, the new and untested elements of the regulatory regime mean that there may be unexpected and unintended outcomes that will need to be worked through. Ergon Energy therefore believes that in the initial stages, there needs to be conservatism, flexibility and interim approaches to schemes (such as low powered risks and rewards, paper trials, etc).

Similarities with the approach to transmission networks

Is it reasonable to apply to DNSPs an EBSS with the same general approach as the transmission EBSS? Are there any significant differences between transmission and distribution businesses that would require a different approach?

Although Ergon Energy agrees that it is reasonable to develop an Efficiency Benefits Sharing Scheme (EBSS) for DNSPs that has the same general approach as the EBSS applying to TNSPs, a DNSP's state-based legislative and regulatory obligations should be explicitly recognised in the EBSS development process.

In general, DNSPs are subject to more state-based regulation than TNSPs as a consequence of the relationship that exists between DNSPs, retailers and end-use customers (e.g. obligations to supply). That is, a DNSP will usually be seen as having more direct impact on the economic environment of the communities in which it operates than a TNSP. These factors should be recognised by the AER when establishing an EBSS framework.

Nature of capex

Would the application of an EBSS to capex yield significant benefits to consumers to offset the risk of windfall gains and losses? Could forecasts and/or actuals be adjusted ex post to reduce the risk of windfall gains and losses to acceptable levels?

While Ergon Energy may at some time (but not now) support an EBSS related to capex, it is difficult to definitely state that it would yield sufficient benefits to customers to warrant its introduction. Ergon Energy is therefore not convinced of any overall benefit of a capex EBSS.

There are a number of issues that would need to be taken into consideration in developing an appropriate framework. For example:

- DNSPs operate on the basis of standardisation in both design and operating practices to bring efficiencies in the provision of their services. Therefore, the ability to tailor one or a number of capital investments is generally less for a DNSP than for a TNSP, where the large and unique nature of investments provide more scope for customised design;
- In general, a single capital investment is usually to the benefit of a subset of the customer base. However, it is the entire portfolio of capital investments within a period that should be considered in any EBSS that relates to capex;
- Many larger projects can take a number of years to complete. The treatment of projects that are carried across periods will need to be considered; and
- Overspend or underspend of capex against forecast would need to recognise and account for a multitude of exogenous factors. In a diverse supply area, individual projects are adjusted in scope and timing for localised issues, accounting for these influences will require detailed understanding of capital works programs by the Scheme's operators.

Ergon Energy believes that these factors need to be carefully studied and understood prior to the development and introduction of any EBSS that relates to capex.

On the issue as to whether forecasts and/or actuals should be adjusted, Ergon Energy does not support the concept of an ex post review of capex.

Further to this, Ergon Energy does not consider the concept of possible windfall 'gains' and 'losses' raised for consideration in the Issues Paper to reflect the likely operation of the EBSS, given that the EBSS is intended to address the issue of sharing gains in capital efficiency with customers.

Incentives to defer capex

Would the application of an EBSS to capex provide inappropriate incentives to delay capex?

Ergon Energy does not believe that an EBSS applied to capex would, if correctly designed, provide inappropriate incentives to delay capex:

- DNSPs detail the interrelationship between capex and operating expenditure (opex) as part of the ex ante approach. Once the Determination has been made, it is the business' responsibility to make appropriate decisions to either capitalise or expense its activities when providing regulated services to customers; and
- DNSPs are subject to the Cost Allocation Guidelines and a DNSP's CAM is approved by the AER.

Within a portfolio of projects, decisions regarding timing or deferral are necessarily a part of managing capex and opex efficiently. Customer feedback and service standards (including any service target performance incentive scheme) also assist in counterbalancing any incentive that may exist to inappropriately defer capital.

Impacts of EBSS for incentives for demand side response and distributed generation

Would the application of an EBSS to only opex materially impact DNSPs' incentives to undertake demand side responses and invest in distributed generation?

Ergon Energy does not believe that an appropriately designed EBSS applied to either capex or opex would materially impact a DNSP's incentive to undertake demand side response or distributed generation. Demand side response, including distributed generation, are part of the 'toolkit' that a DNSP uses to meet its service obligations. A DNSP will balance the capital and operating costs of a number of technically and financially viable solutions in meeting the requirements of the customer and the interests of others.

Other issues regarding inclusion of capex

Are the incentives for efficient capex in the broader regulatory framework sufficient or is there also a need for an EBSS that incorporates capex? How would the exclusion of capex from the EBSS affect the overall regulatory incentives faced by DNSPs? In considering whether or not it is appropriate to include capex in the EBSS for distribution networks, what issues should the AER consider in addition to those discussed in this issues paper?

The current process of ex ante review of forecast capex coupled with a required explanation of the interrelationships between capex and opex forecasts and the AER's approval of a DNSP's CAM should provide adequate assurance that capex will be prudent and efficient.

It is Ergon Energy's view that any EBSS penalty attached to capex overspend should be structured with regard to the fact that the DNSP is already penalised by having made an unfunded expenditure that will not attract a return until the next regulatory period.

Treatment of distribution losses

Is there any evidence available showing that the current level of distribution losses is significantly greater than the economically efficient level? If a distribution loss scheme is found necessary, would either of the Ofgem or IPART schemes be appropriate given the requirements of the NER? If not, what would be the best form of scheme?

Generally, DNSP's have a large number of small jobs and rely on standard designs and materials to deliver efficiency in operations and capital investments.

Losses on a distribution system are largely an outcome of planning and purchasing decisions made independently of a particular project.

DNSPs and TNSPs have always been acutely aware of the life cycle costs of the assets they purchase and/or design. Most, if not all, DNSPs:

- Would have developed purchasing and design standards that consider the life cycle costs of the assets used including the electrical losses over the operating life of the assets. The standardisation of designs and material brings efficiency to operating and maintenance practices and stock holdings. Significant items of plant such as power transformers are purchased under contracts on a forecast life cycle that includes a cost of losses to produce an optimal design of the plant; and
- Would undertake reviews of these design and operating standards and purchasing contracts and adjust the cost of losses parameters according to system load profiles, load factors and load loss factors.

Ultimately, losses are part of the trade off between a 'standard' design and purchasing approach that brings economies of scale and a 'specific' design approach where the objective might be (but is not limited to) loss minimisation.

Ergon Energy does not believe that there is evidence to suggest that the current levels of distribution losses are significantly greater than the economically efficient level.

Ergon Energy does not support a distribution loss scheme.

Linkages with information requirements

Is it reasonable to require DNSPs to provide the proposed information? Is there any further information that DNSPs should provide to assist in achieving the objectives of the scheme?

Ergon Energy believes that:

- The information and data supporting an opex EBSS is likely to be similar to the information requirements applied to TNSPs; and
- The information and data requirements for a capex or distribution losses EBSS will depend on the scheme's framework. It is impossible therefore to comment on whether data and information will be available in a format that supports the EBSS without detail as to the nature of the scheme and its operation.