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16 May 2008

Mr Mike Buckley
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Network Regulation North Branch
Australian Energy Regulator
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Dear Mr Buckley

Issues Paper: Potential Development of Demand Management Incentive Scheme for ENERGEX, Ergon Energy and ETSA Utilities

Ergon Energy Corporation Limited (Ergon Energy) appreciates the opportunity provided by the Australian Energy Regulator (AER) to comment on the potential development of a Demand Management Incentive Scheme to apply to the distribution network service providers in Queensland and South Australia for the 2010 – 2015 regulatory control period.

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

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.

Yours sincerely

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Ergon Energy Corporation Limited

Issues Paper – Potential Development of Demand Management Incentive Schemes for ENERGEX, Ergon Energy and ETSA Utilities – Submission

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Overview

Ergon Energy Corporation Limited (Ergon Energy) welcomes the opportunity to provide comment to the Australian Energy Regulator (AER) on its *"Issues Paper – Potential development of demand management incentive schemes for ENERGEX, Ergon Energy and ETSA Utilities for the 2010-2015 regulatory control period"* (Issues Paper). This submission is provided by Ergon Energy in its capacity as an electricity distribution network service provider (DNSP) in Queensland.

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

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

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

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

Ergon Energy's understanding of the Issues Paper is that the AER views the demand management incentive scheme (Scheme) as comprising two elements:

- A **revenue adjustment mechanism** (e.g. a D-Factor allowance relating to a WAPC); and
- An **allowance to undertake activities** (e.g. a Demand Management Innovation Allowance).

Ergon Energy notes that this is a different approach than has been adopted for the other schemes under the National Electricity Rules (Rules), in that neither element is strictly a penalty or reward, albeit the mechanisms proposed for a Scheme are both 'at risk'. We discuss this further in section 1.

While a Scheme is one mechanism by which efficiencies in the delivery of distribution services may be increased, the application of such a Scheme for Queensland should accommodate the current situation which is that:

- The AER has yet to consult about and consider a national Scheme;

- Demand management initiatives in Australia are in the developmental stage, and there is insufficient information to reliably predict how a Scheme will impact on DNSPs, other participants in the National Electricity Market and customers. There is also uncertainty as to the way in which a Scheme will interact with other schemes (e.g. Efficiency Benefit Sharing Scheme - 'EBSS', and Service Target Performance Incentive Scheme – 'STPIS') which are also still under development and which have never been applied in Queensland;

- There is limited consideration and articulation of the Scheme's objective. Ergon Energy believes that the Issues Paper leaves unresolved the question as to what the Scheme is seeking to achieve in the context of the broader regulatory framework for demand management. This issue is discussed in section 1; and

- For the Queensland DNSPs there is insufficient clarity regarding the form of price control that will be applied[1] and the Scheme's interaction with concurrent regulatory reforms, including: the MCE's cost-benefit analysis of smart metering; the AER's development of a national Scheme; and the AEMC's consideration of mechanisms for facilitating demand side participation in the National Electricity Market. These issues are discussed in section 1.

While these policy and regulatory uncertainties continue to exist, Ergon Energy believes that:

- Ergon Energy should implement a series of demand management projects in the next regulatory control period which are focused on building its demand management experience and capability;

- This suite of demand management projects would be included in Ergon Energy's Regulatory Proposal and would be funded through quarantined operating expenditure (opex) and capital expenditure (capex) and be approved by the AER at the time of making its Distribution Determination on an ex ante basis;

- The opex allowance under the Scheme should be explicitly quarantined from the opex calculation applied under the EBSS; and

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

The arrangement proposed by Ergon Energy would appear to be compatible with the second of the two elements the AER discusses as comprising a Scheme (i.e. an allowance to undertake demand management activities).

[1] The control mechanism and classification of services will not be known until 31 August 2008.

1. Introduction

Ergon Energy notes that the Issues Paper Page 3 states a purpose that is very broad:

> *The purpose of applying a DMIS is to reduce the barriers to demand management and encourage DNSPs to undertake an efficient level of demand management in response to rising demand on their networks.*

Clause 6.6.3(a) of the Rules refers to a Scheme which provides:

> *…incentives for Distribution Network Service Providers to implement efficient non-network alternatives or to manage the expected demand for standard control services in some other way.*

Ergon Energy seeks clarification on the AER's interpretation of the Scheme objective in the context of clause 6.6.3(a) of the Rules. For example, whether the objective of the Scheme is to:

- Reduce network demand (i.e. demand management);
- Reduce the electricity bills of end-users;
- Facilitate demand side participation (i.e. non-network alternatives); and/or
- Achieve environmental benefits.

Ergon Energy queries whether objectives aimed at the pursuit of environmental benefits and a customer's reduction in consumption, would be considered to fall within the intended scope of clause 6.6.3(a) of the Rules. This issue was the subject of comment by the Standing Committee of Officials' response in Bulletin 85 (13 April 2007 – page 2 Item 8) where it stated:

> *Not accepted. The purpose of the NEL framework is to guide economic regulation which should be guided by a unified objective of efficiency that is in the long-term interests of consumers. Environmental and social objectives are best dealt with through other legislative instruments and policies.*

As a philosophy, Ergon Energy believes that schemes in general are not a substitute for the funding required by DNSPs to efficiently operate their networks (i.e. their allowable capital and operating expenditure). Instead, schemes are penalty and reward mechanisms in response to the way in which DNSPs apply the Rules and operate. Schemes in general are most useful where behaviour and obligations are not articulated in the Rules (e.g. if there is no Rule requirement to 'improve', then a scheme may provide such an incentive).

It is important to note that, with respect to demand management, the Rules are already very specific (in both Chapters 5 and 6) about the way in which DNSPs must consider non-network alternatives and in particular, apply the Regulatory Test. Therefore, the objective of any Scheme needs to be set having regard for these pre-existing obligations. We envisage that, for example, a Scheme may penalise or reward DNSPs for the way in which they adhere to the Rules, or a Scheme may provide incentives to do more than is required in the Rules, or more than is allowed for in the Distribution Determination's capex and opex.

Ergon Energy believes that without a clear national Scheme objective:

- It is impossible to determine whether the Scheme to be applied in Queensland, South Australia, or any other jurisdiction, should be targeted to address specific demand management concerns (e.g. areas of congestion) or be broad-based (e.g. applicable to all customers or demand across the network as a whole); and

- The AER, DNSPs and other interested parties will easily lose sight of the fact that the Scheme is only one part of a broader economic regulatory framework that is encouraging DNSPs to pursue the most efficient means of meeting network demand and customer needs. This creates the risk that the Scheme will duplicate or counteract existing or intended demand management activities – i.e. the Scheme will deliver no 'value add' to that which exists under the current regulatory framework (which does accommodate demand management incentives and obligations) and will result in an additional layer of administrative complexity, potentially stymieing the progress of demand management initiatives and trials.

Ergon Energy believes that, in order to implement a Scheme (either for Queensland/South Australia or nationally), there is a need for:

- A detailed consideration and articulation of the Scheme's objective in the context of clause 6.6.3(a) of the Rules and the broader economic regulatory framework for demand management. The range of policy and regulatory requirements influencing each individual DNSP's operating environment may necessitate the development of a different Scheme objective for each DNSP (i.e. there may be variation both between and within jurisdictions); and

- Clarification by the AER as to how it intends to interpret and apply the matters to which it must have regard in developing and implementing the Scheme under clause 6.6.3(b) of the Rules.

2. Operating environment for demand management

In addition to the regulatory requirements and initiatives for demand management referred to in section 2.4 of the Issues Paper, the following obligations impact the demand management activities of Ergon Energy:

- Section 42(d) of the *Electricity Act 1994* (Qld), provides that it is a condition of Ergon Energy's distribution authority that:

  > *The entity must consider both demand side and supply side options to provide, as far as technically and economically practicable, for the efficient supply of electrical energy.*

- Clause 5.6.2 of the Rules requires that a DNSP must conduct a Regulatory Test in any situation where it is augmenting its network as a result of an identified limit in the network's technical capacity and the costs of the augmentation exceed $1 million. The Regulatory Test is expressly intended to draw out demand side and other non-network alternatives to network augmentation.

  Clause 5.6.2(g) provides that:

> *Each Distribution Network Service Provider must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the regulatory test…*

This analysis is required to be included in any consultation that it is required to undertake.

Clause 5.6.2(f) provides that, with the exception of new small distribution network assets (i.e. those requiring expenditure of between $1 million and $10 million):

> *…the relevant Distribution Network Service Provider must consult with affected Registered Participants, NEMMCO and interested parties on the possible options, including but not limited to demand side options… to address the projected limitations of the relevant distribution system…*

3. Current demand management initiatives

No comment is provided.

4. Options for DMIS

Ergon Energy recommends the following framework for application to the Queensland DNSPs in the next regulatory control period:

- Ergon Energy would implement a series of demand management projects and initiatives, in addition to those discussed in section 3 of the Issues Paper. These demand management projects and initiatives will be aimed at building Ergon Energy's demand management experiences and capability (i.e. "learn and do" for demand management products, technologies and capabilities). The initiatives would be a demonstration to other parties as to what are potentially viable projects and initiatives that deliver real benefits and alternatives for DNSPs;

- The suite of demand management projects and initiatives would be:

  - included in Ergon Energy's Regulatory Proposal;

  - funded through quarantined opex and capex (as appropriate); and

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

- The opex allowance under the Scheme should be explicitly quarantined from the opex calculation applied under the EBSS; and

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

Although Ergon Energy believes that it is premature to introduce anything other than an allowance to undertake demand management activities for Queensland for the next regulatory control period (i.e. from 1 July 2010) in advance of a national Scheme, the following comments are provided with respect to the structure of any future Scheme:

- **D-factor** – Of the options proposed for consideration by the AER in the Issues Paper, Ergon Energy does not support the application of a D-factor in Queensland (where a revenue cap is proposed for Network Services) on the basis that:

  - The driver for implementing the D-factor (i.e. the disincentive under a Weighted Average Price Cap to reduce demand and thereby reduce revenues) is inconsistent with a revenue cap form of control, under which revenue is independent of the level of energy consumed. Ergon Energy supports de-coupling energy throughput from revenue, and therefore a revenue cap form of control has been proposed to apply in the next regulatory control period to Ergon Energy's standard control services for the shared network;

  - Efficiencies and benefits resulting from the D-factor are as yet unproven; and

  - The specific network congestion issues targeted by the D-factor are largely addressed by DNSPs through the application of the Regulatory Test which is intended to draw out non-network alternatives to network augmentation.

- **Funding** – The approximate 0.1% per annum of revenue applied under the demand management innovation allowance in NSW is not sufficient to recognise the cost of undertaking trials or development activities over the 'sample' of customers required to obtain meaningful and reliable results. This is an issue of particular importance in those jurisdictions, such as Queensland, where there is limited developed demand management capability, a large geographic area and a low customer density.

  Ergon Energy believes that an appropriate level of funding for "learn and do" needs to be in the order of 0.5% - 1% per annum of annual revenue requirement (ARR), provided that the suite of projects satisfy the opex and capex criteria in clauses 6.5.6(c) and 6.5.7(c) of the Rules. This amount should be in addition to any expenditure allowance for a DNSP's existing demand management programs and any funding derived from other sources (e.g. from the Shareholder).

- **Allowances** – The 'use it or loose it' basis of the NSW and ACT innovation allowance has the potential to drive poorly structured trials that are undertaken hastily by a DNSP to ensure that funding is not 'lost'.

  Ergon Energy believes that any 'allowance' or 'expenditure recognition' should be available for use in aggregate over the determination period, with flexibility to recognise trials that run over two or more years. For example, a mild summer may not give useful trial results, requiring an extension of the trial to the following summer.

5. Request for submissions

5.1 Question 1

What are the incentives and disincentives for QLD and SA DNSPs to undertake demand management?

As noted in section 2, although Ergon Energy does not currently operate under a Scheme, there are a range of regulatory requirements which require the formal assessment of non-network alternatives to network augmentation in circumstances where it is technically and economically practicable. This includes the requirement under clauses 6.5.6(e)(10) and 6.5.7(e)(10) of the Rules for the AER, in accepting a DNSP's opex and capex forecasts, to be satisfied of the extent to which the DNSP has considered, and made provision for, efficient non-network alternatives.

The extent to which these regulatory requirements or any Scheme are adequate to deliver the required incentives (or mitigate potential disincentives) will depend on the objective that is sought to be achieved through application of the Scheme.

Ergon Energy does not believe that incentives and disincentives can be balanced without a clear sense of the Scheme's objective.

5.2 Question 2

Is it necessary to apply a DMIS in QLD and/or SA, given the likely effect on customer prices and customer willingness to pay for an incentive for a DNSP to conduct demand management?

Ergon Energy only supports the application of a Scheme that comprises an allowance to undertake demand management activities in Queensland for the next regulatory control period (2010-15). Ergon Energy believes that there is ample scope within the existing regulatory framework for it to pursue demand management projects and initiatives over the course of the next regulatory control period, while the AER develops a national Scheme which takes account of the MCE's and the AEMC's concurrent reforms. A national Scheme will also move towards meeting the objective of consistency between all jurisdictions' DNSPs regulatory arrangements.

As a general comment however, the magnitude of any impact on customer prices or customer willingness to pay as a consequence of a Scheme will vary with the nature of the initiative pursued.

The issue of the delivery of price signals to customers in Queensland is discussed in section 5.4.

5.3 Question 3

Do particular control mechanisms, such as tariff basket, revenue yield or revenue cap arrangements create incentives or disincentives for a DNSP to conduct demand management?

Ergon Energy agrees that a control mechanism can influence the effectiveness of demand management incentives under the Scheme. For example, the driver for implementing a D-factor (i.e. the disincentive under a Weighted Average Price Cap to reduce demand and thereby reduce revenues) appears inconsistent with the revenue cap form of control, under which revenue is independent from the level of energy consumed.

The relative incentives and disincentives for each DNSP to conduct demand management will need to be assessed in the context of the specific control mechanisms and service classifications that will apply to that DNSP, following completion by the AER of its Framework and Approach process.

5.4 Question 4

Are DNSPs able to offer efficient pricing structures, and how does this effect the need for a DMIS?

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

It should be noted however that due to inelasticity in customers' response to price signals, prices are only one aspect of any process intended to motivate customers to reduce or manage their demand.

Regardless of the efficiency of Ergon Energy's distribution pricing structures, Ergon Energy is in a unique position in Queensland that:

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

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

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

These factors will limit the ability for customers to receive and respond to the price signals that are communicated through Ergon Energy's pricing structures. As Ergon Energy's ability to deliver price signals differs from that applying to ENERGEX, these practical barriers also emphasise the importance of identifying a Scheme objective that will apply to each DNSP.

5.5 Question 5

Do lessons learned from the QLD or SA jurisdictions or other jurisdictions provide any insight into the potential development of DMIS to QLD and SA DNSPs?

Only a small number of dedicated demand management trials have been initiated to date in Queensland and none have yet been adopted as broad-based alternatives to network augmentation. The key lessons from this are that:

- Demand management trials and programs in Queensland are in the early stages of development; and

- The introduction into Queensland of a Scheme that is mature in another state would be premature. The framework for Queensland should allow for the continued development by the Queensland DNSPs of demand management experience and capability.

5.6 Question 6

How do DMIS interact with other incentive schemes, such as efficiency benefit sharing schemes, or service target performance incentive schemes?

Ergon Energy raises the following issues regarding the Scheme's interaction with other incentive schemes under the Rules:

- A DNSP should not be penalised under the EBSS as a consequence of its demand management related expenditure under the Scheme. Opex under the Scheme should be excluded from the operation of the EBSS[2];

- A DNSP should not be penalised twice for its performance or service failures. For example, a DNSP should not be penalised for both a failure to achieve a demand management outcome under the Scheme and for a failure to meet a service performance target under the STPIS. The balancing of rewards and penalties across the schemes will require detailed consideration; and

- Consistent with the comment in section 5.4, incentive schemes may, individually or in aggregate, result in side constraints on network prices being exceeded and therefore the loss by the DNSP of the 'reward/s'. 'Banking' mechanisms, similar to those proposed to apply under the STPIS, may be required to manage this potential outcome.

[2] Clause 11.16.4 of the Rules provides that the EBSS for Ergon Energy and ENERGEX for the next regulatory control period must not cover efficiency gains and losses relating to capital expenditure.

5.7 Question 7

What is the optimal structure of a potential DMIS for DNSPs in QLD and/or SA, and what impact is this structure expected to have on the efficiency of DNSPs' decisions?

As discussed in section 4, Ergon Energy recommends the following framework for application to the Queensland DNSPs:

- Ergon Energy would implement a series of demand management projects and initiatives, in addition to those discussed in section 3 of the Issues Paper. These demand management projects and initiatives will be aimed at building Ergon Energy's demand management experiences and capability (i.e. "learn and do" for demand management products, technologies and capabilities);

- The demand management projects and initiatives would be:

  - included in Ergon Energy's Regulatory Proposal;

  - funded through quarantined opex and capex (as appropriate); and

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

- The opex allowance under the Scheme should be explicitly quarantined from the opex calculation applied under the EBSS; and

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

5.8 Question 8

What are the likely costs and benefits of implementing and administering the DMIS proposed in this paper or any other potential DMIS?

Any Scheme that:

- Compensates a DNSP for foregone revenue will have costs associated with forecasting the demand that would have occurred in the absence of the demand management initiative and thereby, the expenditure that is consequently avoided by the demand management initiative. The costs of establishing the avoided demand may outweigh any reward for achieving the demand reduction; and

- Requires preliminary approval of individual projects on an ex-ante basis and final approval of project expenditure on an ex-post basis, will necessarily involve higher administration costs for both the AER and the relevant DNSP than an arrangement which recognises demand management expenditure in tandem with other categories of opex (i.e. on an ex-ante basis).