SUBMISSION ON

"NETWORK PRICING PRINCIPLES"

25 AUGUST 2000

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1 Executive Summary

This document is the submission from Ergon Energy Corporation limited (the Distributor) and Ergon Energy Pty Ltd (the Retailer) to the Queensland Competition Authority (the Authority) in response to the Issues paper titled:

"Distribution Pricing Principles" dated July 2000

The significant issues raised by Ergon Energy in this submission are summarised below.

- Ergon Energy reiterates its preference for a hybrid revenue cap as the primary form of price control as they provide a clear incentive to the Distributors to minimise costs and maximise network utilisation consistent with achieving reasonable returns on the assets deployed.

- Ergon Energy's position is that the QCA approve a set of pricing principles, not attempt to regulate the individual prices charged to customers.

- With the inclusion of two additional objectives, Ergon Energy generally supports the listed objectives as providing a sufficient basis upon which to assess the need for regulatory action regarding the structure of network prices.

- Ergon Energy's current pricing principles are based very closely on Part E of the National Electricity Code (NEC). However, we recommend that the Authority retain a level of flexibility and use the code as a guideline not to be applied in its absolute.

- It is Ergon Energy's position that prices should reflect the Long Run Average Costs of the business.

- Ergon Energy believes that it is acceptable to conclude that there is a range of prices that satisfy efficiency considerations.

- If side constraints are to be adopted by the Authority it is Ergon Energy's position that these should be addressed through a mechanism where guidelines are determined which do not limit the ability to change prices where costs or cost drivers change.

- If side constraints are to be used by the Authority, Ergon Energy believes that the approach adopted by IPART in NSW is appropriate. That is the side constraints should be set at the maximum of a fixed dollar value or a percentage value.

- It is Ergon Energy's position that the Authority should determine the total revenue cap but the derivation of network tariffs should be left largely to the Distribution Businesses management. We agree that it is necessary to place some discipline on this process and so for transparency a requirement to publish the tariff setting methodology is appropriate.

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2 Introduction

The Queensland Competition Authority (the Authority) has invited submissions from interested parties concerning the need for the Authority to establish distribution pricing principles and the form of such principles. To assist in this process the Authority published an Issues Paper (the paper) titled "Network Pricing Principles" seeking comments by 25 August 2000.

We welcome the opportunity to comment and ask that you accept this submission as Ergon Energy's contribution to this particular aspect of the consultation process.

3 Preliminary Comments

Pricing for access to electricity networks is a relatively new topic in the context of the Australian electricity industry. Ergon Energy is firmly of the belief that network prices need to reflect the efficient costs to foster appropriate use of and investment in the network. However, due to the extensive networks involved in electricity distribution and the number of customer connections, pricing for these networks involves a greater degree of averaging (equity drivers) than is required for transmission pricing. The main issue is how best to allocate the maximum allowable revenue among customers in the most efficient or least distortionary manner while maintaining an appropriate degree of equity.

In Queensland, in particular, there is also a social and political imperative for pricing structures to support regional development. Much of the rural network was developed as part of a Government supply policy with significant subsidies offered. The on-going cost of supporting these systems could impact on regional development if the costs are not sufficiently separated (efficiency signals) ie the cost to major industrial and commercial centres needs to be appropriate to support development in a competitive energy environment.

This submission needs to be considered in the context of Ergon Energy's business. Ergon Energy Corporation Ltd was incorporated on 24 May 1999 following the bringing together of the six regionally based electricity distribution companies in Queensland. It services approximately 560,000 customers through 140,000 km of distribution and sub-transmission lines located in over 1M sq km of regional Queensland.

In this submission Ergon Energy has addressed some general price control and pricing principles issues and then provided detailed response to the issues raised in the paper.

3.1 Form of Primary Price Control

As previously advised in our submission on the Framework for Regulation, it is Ergon Energy's position that Electricity Distribution businesses have significant fixed costs including:

a) Return on capital to shareholders,
b) Depreciation to fund the replacement of ageing system and other assets, and
c) The operation and maintenance costs of a developed network to support the delivery of a safe and reliable supply of electricity to an existing customer base.

These costs will apply largely irrespective of short-term fluctuations in the demand on the network. In this context, these fixed costs should be considered as the running costs of a "zero capacity network" which provides connection services to an existing and ongoing customer base. The regulatory price control option must address these committed distributors' costs and in doing so seek to optimise and appropriately assign the revenue recovery risk.

Hybrid Revenue Cap arrangements are recommended by Ergon Energy in preference to specific price cap and fixed revenue cap type regulatory mechanisms.

Price Cap regulation would expose both customers and the Distributors to significant volume variance risk, particularly in regional Queensland where the customer mix delivers high correlation of energy throughput variances to climatic and economic conditions (both of which are difficult to forecast). A significant amount of the Ergon Energy electricity throughput is dedicated to major resource and industrial customers and this exposes Ergon Energy to significant revenue recovery risk, particularly that arising from the economic and business cycles of our customers. Although each of the six previous organisations comprising Ergon Energy produced forecasts in the past, as a relatively new entity the total organisation's forecasts are not yet adequate to mitigate this risk. Ergon Energy contends that the use of a price cap mechanism would increase the overall business risk and have material impacts on the Weighted Average Cost of Capital (WACC).

Of significant concern to Ergon Energy is the current and ongoing development in the National Electricity Market and the impacts of that development on the regulated Network Businesses. Market changes during the regulatory period may render the prices established at the commencement of the period (P_0) either inadequate or unsustainable. In addition, the capping of prices would preclude any refinement of the prices during the regulatory period, hence exposing Customers and/or Distributors to price shocks at the regulatory reset. The introduction of Full Retail Contestability is one such issue that will require a significant degree of flexibility over time in network prices to ensure a successful implementation.

A hybrid revenue cap on the other hand would allow the Distributors to refine the prices during the regulatory period based on market developments, the introduction of new technologies and the uptake of demand side options. The hybrid revenue cap type regimes allow Distributors to develop and implement improved network pricing structures within the regulatory period, where the structural components encourage customers to improve network utilisation and operational efficiencies.

Finally, price-capping arrangements can be seen to be at odds with economic efficiency, particularly as regards to the drivers on the Distributors to optimise their revenue streams. If price caps were adopted, Distributors would be inappropriately encouraged to increase system energy throughput at the expense of system utilisation and efficiency, all in order to maximise the income stream.

Hybrid revenue caps however can provide a clear incentive to the Distributors to minimise costs and maximise network utilisation consistent with achieving reasonable returns on the assets deployed.

3.2 Level of Regulation

Under section 301 of the *Electricity Act 1994* the Network businesses are only allowed to charge prices approved by the minister. This current process is cumbersome and fraught with potentially lengthy delays in obtaining pricing approval. It is Ergon Energy's position that the regulatory framework should set the overall revenue targets. The outworking and delivery of those targets as structured network charges should be the responsibility of the Distributors. This approach will ensure that the Distributors can respond to the changing electricity market environment and customer requirements in a dynamic way.

When the QCA sets the Maximum Allowable Revenue (MAR) for the businesses they will do so on the basis of the businesses being efficient. If the QCA then wishes to have an active role in price setting it would potentially cause secondary effects (administrative and regulatory costs) that could affect the way in which the businesses were able to achieve the efficiencies assumed in the MAR calculation.

Ergon Energy's position is that the QCA approve a set of pricing principles, not attempt to regulate the individual prices charged to customers. As a transition we would be prepared to submit our worked up initial prices to the QCA for the first regulatory period to provide the regulator and our customers with a degree of comfort and transparency in relation to the prices being set.

4 Detailed Comments on the Issues Paper

The subheadings in this section of our submission refer to the headings in the Paper. This is a response to certain statements made in the paper.

4.1 1. Introduction

Last dot point on page 2 of the paper states: *"having price reviews which are aligned with standard accounting periods".* Ergon Energy agrees that there are benefits in following this principle but wishes to have it understood that any process for price reviews and the timing for those reviews must include the approval and publication process.

4.2 2.2 Existing Regulatory Regime

The second paragraph: *"The most recent Ministerial determination of distribution pricing….."* The determination quoted in the paper refers to tranche 3 price books only. The most recent determination was in June 2000 and included price books as well as site specific prices.

The third paragraph, second dot point refers to high voltage metered volume and large, medium and small volume charge categories. Volume charges have been determined to be a transitional arrangement up to 1 July 2001. After that date it is intended that all customers will revert to the appropriate demand charge. The current pricing determination applies only to the current contestable tranches of customers and we would like to reserve the right to consider the application of volume based charges for smaller customers following the implementation of Full Market Contestability.

4.3 3.3 Network Tariffs in Queensland

"The only network charges applicable to generators are connection charges." This statement is correct for transmission connected generators, however under the code, generators embedded in the distribution system may be charged for distribution system augmentation.

4.4 6.3 Alternative Pricing Methods

Page 19, first dot point: *"there is no recognition given to spare capacity on the network which, particularly in remote areas with low load growth rates, allows significant additional load to be supported by the network with little or no network development required."*

Ergon Energy wishes to have it on record that generally there is no spare capacity in lines built in remote areas because the line is designed to ensure that the statutory voltage is maintained. Although the conductor may nominally carry more load, in reality, any additional load will cause excessive voltage drop on the system.

4.5 7.2 Approval of Pricing Principles.

First Paragraph: *"No approvals have been required of the DNSP's pricing principles or strategies".* This statement is not correct. The Electricity

Reform Unit (ERU) and their predecessor the Queensland Electricity Reform Unit (QERU) have controlled the complete process. Both Queensland distribution businesses utilise a "Distribution Cost of Supply" (DCOS) model which was developed in conjunction with and approved by ERU (QERU). All prices that have been submitted to the Minister for approval have been required to be developed utilising the DCOS model.

5 Specific Response to Issues Requested

The QCA sought specific comments on issues raised throughout the paper. The following is Ergon Energy's comments on these issues.

5.1 Objectives of Network Pricing

The Authority seeks comments on:

> **Whether the listed objectives provide a sufficient basis upon which to assess the need for regulatory action regarding the structure of network prices?**

Ergon Energy believes that several additional objectives should be added to the list included in the paper.

- Prices consistent with revenue recovery
- Simplicity

With the inclusion of the above Ergon Energy generally supports the listed objectives as providing a sufficient basis upon which to assess the need for regulatory action regarding the structure of network prices, but recognises that the outworking of these objectives will need to be accompanied with appropriate/improved pricing principles. Pricing outcomes will also need to take account of what is achievable from a practical level including:

- Data availability;
- Implementation and operating costs;
- The stability of prices; and
- Price simplicity.

Specifically in relation to improved pricing principles, looking at the paper, dot point 3, "*Efficient Investment in Infrastructure Augmentation,*" this can be achieved either through a full cost reflective pricing regime or a macro zone averaging coupled with an access hurdle (capital contribution). From simplicity and equity considerations the use of macro averaging is a useful compromise. However it is important that customers face appropriate and full investment information in terms of considering supply options (ie stand alone vs grid). The current Capital Contributions policy only considers the fixed cost of installing the asset and not the ongoing future operation and maintenance of the asset. This results in a distortion of the investment decision process.

As indicated earlier in this submission, distribution pricing requires a greater degree of averaging than transmission pricing and it is our contention that an appropriate Capital Contributions policy would include a component that effectively gave the customer access to the DUoS average pool, equivalent to paying the shortfall in DUoS contributions.

In addition it is Ergon Energy's position that the regulatory framework must allow a level of flexibility. In our submission to the Authority's discussion paper on Determination of Prescribed Services we wrote:

> *"That Ergon Energy supports prescribed services being the "standard regulated offer". However where the customer seeks to vary that arrangement, as a general principle, the negotiated arrangement becomes an "excluded service" and not subject to economic regulation nor subject to the tests of "market" and "effective competition" proposed, provided the customer fits within a qualifying parameter".*

Obviously the qualifying parameter would need to be agreed with the Authority, but as a minimum we would suggest that it align with the current Individually Calculated Customers (ICC) and Connection Asset Customers (CAC) (the larger end of the customer market). Again this is consistent with appropriate economic drivers of competition where a reasonable operating market exists.

What relative weighting should be given to the various objectives, especially:
- what role should equity play relative to economic efficiency?
- what emphasis should be given to the role of locational signals in pricing?

Economic efficiency objectives are to set prices that encourage optimum use and distribution of resources. The community's economic goals are to allocate resources at a cost no more than their next best alternative. In the case of electricity networks, the next best alternative can be viewed as:

- Alternative use of the capital to invest in the infrastructure. The cost of capital invested in networks has an opportunity cost.
- Alternative to the network. Embedded generation, alternative networks fall into this category. The cost of an alternative service sets the competitive price above which a network service provider cannot exceed.

It is Ergon Energy's position that economic efficiency needs to be given significant weight. We reiterate though, that network pricing does require a high degree of averaging thereby allowing the economic efficiency objective to be met by alternative mechanisms such as a Capital Contributions policy.

The principle of equity is a subjective one. Generally, the principle relates to users paying for their fair share of costs. The judgment on fair share can depend on the customer's elasticity of demand, market power and bypass options. In allocating costs on an equitable basis, it is important to be explicit about the equity principle and cost allocation rules. The network service provider to be fair to all customers must adhere to the resulting allocations.

It is our view that the various objectives are weighted in the following order:

Macro efficiency (zoning) → **Equity (price equity)** → **Micro efficiency (entry costs)**

Locational signals are essential in a network pricing regime, but not to the extreme of full nodal pricing at distribution level – cost and complexity with little benefit.

Whether the requirement that the pricing regime should not discriminate between users is a sufficient allowance for equity?

Ergon Energy agrees that the requirement that the pricing regime should not discriminate between users (within zonal boundaries consistent with the macro drivers) is a sufficient allowance for equity.

What emphasis should be given to the role of incentives in pricing?

In our submission to the Authority in response to the "Framework for Regulation" Issues paper Ergon Energy stated that it supports the adoption of a hybrid revenue cap mechanism similar to the New South Wales approach where the operating cost efficiencies, (small x factor), are identified and included in the forecast operating and maintenance building block components. These should be able to reflect changes in efficient costs arising from feasible variations in customer demand over the control period. A hybrid formula would substantially limit the incentive for artificially promoting energy consumption, with its attendant economic and environmental costs.

In relation to incentives in the pricing structures aimed at providing signals to customers to influence their usage patterns, these are an extremely important component of any network pricing structure. In line with our position that the Authority should approve a set of pricing principles and not attempt to regulate individual prices, it is our contention that the role of incentives in the pricing structures is left to the individual distribution businesses.

5.2 Characteristics of Efficient Pricing

The Authority seeks comments on:

What role cost reflective network pricing should play in the Authority's regulatory role? Should the Authority exercise its discretion not to apply Part E?

Ergon Energy's current pricing principles are based very closely on Part E of the National Electricity Code (NEC). However, we recommend that the Authority retain a level of flexibility and use the code as a guideline not to be applied in its absolute.

Whether economic efficiency requires that prices reflect forward-looking marginal or incremental costs?

Long run marginal cost (LRMC) prices signal the cost of future augmentation to meet the next increment of load. LRMC is the most appropriate economic price to cover the augmentation of networks. There may be variability in the LRMC depending on the cyclical growth of load. LRMC would provide reasonable price stability because of the time averaging involved. The disadvantage of LRMC is that it falls short of recovering the total cost of the network business where there are large sunk assets.

The cost of providing a given overall network capacity is made up of the sum of many incremental costs in many separate parts of the network. The incremental cost approach is one of extremes. At one extreme , an incremental load increase could be accommodated by the "spare" capacity of an existing portion of the network, and there would be no incremental cost associated with that customer. On the other hand, another incremental load increase where there is no spare capacity available may trigger a significant augmentation project with disproportionately high incremental costs. Incremental costs are therefore not directly applicable or appropriate in recovering the costs of the network through prices.

Currently Ergon Energy uses a form of fully distributed (FDC) or average cost based allocation. This is similar to the approach in Part E of the NEC. Ergon Energy's cost of supply modelling allocates infrastructure costs to classes of network customers. Infrastructure costs are allocated to those customer classes that it is used to serve. Shared asset types are allocated based on the usage by each customer class. Operating and administrative overheads are allocated to customer classes based on the proportion of the use of the network ascribed to those customer classes.

While the economic merits of this allocation method can be argued the Long Run Average Cost allocation method does have a sensible basis for allocation of costs. It removes the problems associated with the subjectivity of pricing principles that can result from one group having greater market or lobbying power than another group. The other major advantage of this approach is that it offers price stability to customers as average costs vary slowly.

It is Ergon Energy's position that prices should reflect the Long Run Average Costs of the business.

Whether it is acceptable to conclude that there is a range of prices that satisfy efficiency considerations?

Ergon Energy believes that it is acceptable to conclude that there is a range of prices that satisfy efficiency considerations. The application of average cost based Distribution charges coupled with an appropriate capital contribution policy is one example of a methodology, other than the fully cost reflective basis for pricing, that is able to satisfy efficiency considerations. The issue is one of arriving at a least cost solution which delivers the appropriate outcomes for customers and the distributors.

Whether network prices should reflect future investment requirements, and so the probability of congestion and the future network augmentation requirements.

In a diversified distribution system, congestion is not really an issue. However, a requirement to met more onerous performance targets would give rise to a significant increase in the investment required in the network. This could give rise to price shocks to customers if the future investment was not reflected in the network prices. Currently Ergon Energy is not forecasting an extra ordinary capital investment and accordingly does not see a need for LRMC costing to be adopted.

Whether prices should take account of network congestion?

It is Ergon Energy's view that network congestion in relation to pricing strategies is more relevant to Transmission with its lumpy capital program than to distribution. Ergon Energy has more issue with managing voltage levels, particularly in the rural areas. Generally there is no spare capacity in lines built in remote areas because the line is designed to ensure that the statutory voltage is maintained. Although the conductor may nominally carry more load, in reality, any additional load will cause excessive voltage drop.

5.3 Regulatory Control Options

5.3.1 Role for Side Constraints

The Authority seeks comments on:

Whether side constraints should be adopted at all by the Authority, and with what pricing objective(s) in mind?

Side constraints address a considerably different objective than the maximum allowable revenue (MAR) formula. Whilst the MAR formula acts to cap total revenues, the side constraints act to reduce the incidence of rate shock to particular customers. Where as the MAR formula is a control on total revenues, the side constraints place a control on movements in particular prices. Thus side constraints support the customer protection objective.

For this reason Ergon Energy understands why regulators make use of side constraints but wishes to highlight in this submission some of the issues that result from the application of rigidly applied side constraints. As already stated in this submission it is Ergon Energy's preference that the Authority approve a set of pricing principles, not attempt to regulate the individual prices charged to customers. The application of side constraints is, we believe, contrary to a more light handed regulatory approach, however it is accepted that they may form a function in the transition to a more light handed approach. Also we wish to point out that side constraints have historically locked in original tariff structures and cost relativities which gradually over time become further and further removed from the price signals which need to be sent out to support the efficient operation of the network business.

In section 4.2 of this submission we stated that the current volume charges have been determined to be a transitional arrangement up to 1 July 2001.

After that date it is intended that all customers will revert to the appropriate demand charge. Rigidly applied side constraints will cause significant problems in moving these customers to demand prices. If, for the efficient operation of the network, it was determined that the introduction of a pricing incentive in the form of kVA tariffs were the appropriate solution, again the application of rigid side constraints will cause significant difficulties in relation to the implementation of these tariffs.

If side constraints are to be adopted by the Authority it is Ergon Energy's position that these should be addressed through a mechanism where guidelines are determined which do not limit the ability to change prices where costs or cost drivers change.

Included in our submission on prescribed services and restated earlier in this submission, is Ergon Energy's position that where the customer seeks to vary from the standard arrangement the negotiated arrangement becomes an "excluded service" and not subject to economic regulation (including the side constraint), provided the customer fits within a qualifying parameter.

Whether any side constraints should only apply to residential customers, or be applied to commercial customers as well?

As indicated above, Ergon Energy believes that the regulatory framework should allow a level of flexibility for the large end of the contestable market. We agree that the application of side constraints to the smaller end of the contestable market is seen as an appropriate customer protection mechanism. However, we wish to highlight that currently network charges are moving away from categorising customers by their end use type. Network prices are being set based on the type of network connection assets employed and the customer load characteristics.

Whether any side constraint should apply to individual end users or just at the customer grouping level?

Reiterating Ergon Energy's position that for the large end of the contestable market, flexibility in dealing with the individual customers is required along with the ability to negotiate outside of the regulated framework. These customers currently have individual network prices now.

For those customers below the qualifying parameter then, if side constrains are to be employed, they should apply at the customer grouping level.

Whether any side constraint should be expressed in terms of a fixed percentage or dollar amount (or both)?

If side constraints are to be used by the Authority Ergon Energy believes that the approach adopted by IPART in NSW is appropriate. That is the side constraints should be set at the maximum of a fixed dollar value or a percentage value.

At what level should any side constraint be set?

In setting the level of the side constraint, consideration needs to be given to all of the factors in place. There is a history in Queensland of significant regulatory control of prices, which has seen the current prices not accurately reflecting costs. There are other institutional factors (the immaturity of Ergon Energy as a business) as well as the introduction of Full Market Contestability (FMC) which will influence the manner in which tariffs may wish to be restructured. The introduction of FMC coupled with the historic clamp on prices, including the uniform tariff and the glide path required to facilitate FMC, makes this a difficult issue to resolve. If contestability is to be effective at the lower end of the contestable market then the distribution businesses need to ensure the correct prices are put into the market prior to the commencement date.

Although typically side constraints are linked to the CPI, as a result of the points raised above it is Ergon Energy's position that the setting of the level of side constraint needs to take into consideration all of the influencing factors.

5.3.2 Approval of Pricing Principles.

The Authority seeks comments on:

Whether DNSP's should be required to submit their pricing principles or strategies to the Authority for approval prior to the commencement of each regulatory control period?

As previously stated in this submission it is Ergon Energy's position that the Authority should determine the total revenue cap but the derivation of network tariffs should be left largely to the Distribution Businesses' management. We agree that it is necessary to place some discipline on this process and so for transparency a requirement to publish the tariff setting methodology is appropriate.

5.3.3 Annual Information/Documentation Requirements

The Authority seeks comments on:

Whether the annual information requirements in support of a DNSP's proposed network tariffs for the coming year should be a matter for the DNSP to determine, or should the information required be specified by the Authority?

Ergon Energy supports the position of the Regulator having input into the process to determine the annual information requirements and is happy to meet any reasonable request. To assist in achieving an appropriate outcome Ergon Energy will seek meaningful discussions with the Authority on this matter each year.

If the Authority specifies its annual information requirements, any supporting quantitative analysis should be restricted to the 'cross subsidy' test (as in Victoria) or extended to cover a wider range of matters (such as in NSW)?

Ergon Energy offers to hold discussions with the Authority to indicate what data can be provided to satisfy the Authority that appropriate pricing is in place. It is Ergon Energy's preference that balance between customer confidence and micro regulation be achieved.