RESPONSE TO DRAFT DETERMINATION

"REGULATION OF ELECTRICITY DISTRIBUTION"

BY

ERGON ENERGY CORPORATION LIMITED

19 FEBRUARY 2001

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1 EXECUTIVE SUMMARY

This document is the submission from Ergon Energy Corporation Limited, referred to as Ergon Energy, to the Queensland Competition Authority (the Authority) in response to the Draft Determination titled:

"Regulation of Electricity Distribution" dated December 2000.

Ergon Energy realises that tight timeframes prevented the Authority from due deliberation in some areas of the Draft Determination and that consequently some preliminary decisions had to be made. Ergon Energy appreciates that the Authority put out the Draft on time as promised. This provides a starting point to working through the issues arising towards a realistic and commercial outcome for the final determination.

1.1 Overview of Ergon Energy's Response

Ergon Energy is a relatively new Corporation formed in 1999 from the merger of the six regional distribution entities. The challenges facing Ergon Energy are immense. Operationally, financially and service-wise, significant reform and strategic realignment is required. The capability development phase required to address the developing market and the significant challenges of managing a large corporation that has emerged from six small regional businesses will require significant expenditure and time.

The Business is faced with enormous legacy issues arising from the decisions and inaction of the predecessor network corporations. The business does not have the core systems or capabilities to adequately manage the electricity assets, the levels of service and supply reliability do not in general meet customer requirements, and the business has inherited an unsustainable cost base and industrial relations environment. The primary focus for the Network Business over the next 2 to 3 years is to address these legacy issues and transform itself into a modern and capable entity.

As the capability development phase for the business falls directly within the regulatory period under consideration in the current QCA revenue determination, it is critical that the current status of the business and the urgent need for major change are recognised and accommodated in the final determination.

This submission is focused on seeking outcomes in the final regulatory determination that are consistent with the business capabilities, service improvement initiatives, and the issues arising from the merger and restructure of the business.

However Ergon Energy is committed to meeting <u>reasonable</u> regulatory targets within the regulatory period.

1.2 Issues with the Unadjusted AARR

The Authority has identified a series of aggregate annual revenue requirements (AARRs) of \$476 million in 2001/02 increasing to \$520.3 million in 2004/2005. Ergon Energy believes that these (unadjusted or full allowance) revenues do not adequately accommodate the business's needs in three key areas:

- **the significant change (merger and restructure) requirements for the business;**

The non-allowance of the merger and restructure costs when combined with the benefit streams directed to the customers, removes all commercial incentives for the business to undertake the change program. Ergon Energy contends that the change program is non-negotiable and due recognition must be given in the determination. The key issue is - the party who funds the change program must retain the benefit streams. The draft determination has the shareholder funding the program with the customer receiving the majority of the benefits. This is not a commercially sustainable position.

In other jurisdictions the Distributors generally had the advantage of restructuring under previous price structures (or prior to a fully regulated regime). The resultant savings were then passed on in the next round of price reviews by benchmarking to best practice. The savings were not passed to the customer as they occurred. Ergon Energy contends that the Authority's approach to the merger and restructure costs is inconsistent with other regulatory regimes and further compromises Ergon Energy's ability to operate in the national market.

Ergon Energy urges the Authority to review its position on the merger and restructure costs to ensure that the financial integrity of the business is maintained while delivering improved value to the key stakeholders.

- **A sustainable approach to taxation and WACC.**

Ergon Energy is of the view that the approach adopted by the Authority eliminates all incentives for tax efficiency, which impacts on financial efficiency, and hence future benefits to customers. In addition, it is questionable whether the Authority's draft determination has met the objectives of the NEC relating to efficient cost of service delivery, and the application of an incentive based regulatory regime. This is one of the fundamental reasons why Ergon Energy believes the Authority needs to reconsider its draft determination, on the issue of tax treatment. Ergon Energy supports the use of a benchmark taxation rate to offer incentives for the DNSPs to effectively manage their taxation position.

In addition the method for determining the risk free rate provides significant issues for Ergon Energy in managing its interest rate exposure. Ergon Energy contends that the "single day" method proposed will increase the debt margin by some 55 basis points. Ergon Energy is seeking a move to a longer-term average rate, if this approach is not undertaken then Ergon Energy seeks an increase in its debt margin if 55 basis points.

Finally the analysis of equity betas and the associated asset betas undertaken by the Authority does not appropriately recognise the risk profile of Ergon Energy. Ergon Energy submits that insufficient attention has been given to establishing whether the Queensland Distributors have different risk profiles. Ergon Energy restates its requirement for an equity beta of 0.92 and an asset beta of 0.55 to better reflect the risk profile of the business.

- **The setting of efficiency targets without due regard to the outlier nature of the Ergon Energy network, the position of it being a newly formed Company, and the requirements for service improvements to regional customers.**

Ergon Energy engaged Indec Consulting to review the TAP and PEG reports. Their review found that "*the efficiency and reliability targets identified in the PEG and TAP reports for Ergon Energy fall significantly outside the range of possibility. It would not be able to attain these targets and still meet the objectives set down by QCA of maintaining its financial integrity and not comprising customer service quality requirements*".

The issues with the efficiency targets recommended by TAP and PEG fall into three broad areas:

- The ultimate efficiency target of 30% below current costs

Indec Consulting's analysis shows that Ergon Energy is an outlier in the developed western world in terms of service area and customer density. Indec conclude that the TAP and PEG analysis does not adequately adjust for these conditions in their models. Ergon Energy is seeking a review of the 30% target in light of the Indec findings.

- The timing of the efficiency cuts,

Indec Consulting have concluded the Ergon Energy needs to undertake a major reform initiative and that consequently the business is not able to produce savings for a period of 2-3 years. Ergon Energy is seeking a review of the efficiency requirements and associated timing of application, in light of these findings.

- The focus on cost cutting rather than service improvement with underlying growth as the means to efficiency.

In the Draft Determination, the Authority has not given adequate consideration to the use of growth and service improvement as a means of bridging the efficiency gap. Ergon Energy requests that the Authority explores these issues and reviews the cost reductions in light of findings.

1.3 Issues with Adjusting of AARR

While there are significant concerns about the full allowance revenues as detailed above, Ergon Energy also has major issues with the Authority's adjusted revenues which result in a $94.8m NPV shortfall over the period of the determination.

Ergon Energy contends that the adjusted revenues are based on a non-commercial approach to shareholder returns. This position is not consistent with the requirements on the Ergon Energy Board under the GOC Act. The Board has given firm commitments to the Shareholder to deliver returns that are consistent with the value of the business and market expectations.

The restrictions in allowable revenues will therefore certainly directly impact on the operating expenditure of the business and further compromise the delivery of satisfactory outcomes to other stakeholders in regional Queensland particularly in the areas of:

- Improvements in service (quality and reliability of supply); and
- Growth/retention of jobs.

Ergon Energy contends that the Authority should make a commercial determination consistent with:

- other regulatory regimes in Australia;
- stakeholder requirements (including reasonable returns to shareholders); and
- the delivery of appropriate commercial and cultural signals to the business.

The current position may have unintended consequences, as the rate of return may recreate an environment in which Ergon Energy is unwilling to invest in the early years of the regulatory period.

The determination should <u>not</u> be recommending on Shareholder policy.

Ergon Energy accepts the need to manage impacts to customers, however this issue should be dealt with through appropriate consultation with Government to ensure consistency with a range of other broader energy policy initiatives such as Full Market Contestability, industry restructure, and Community Service Obligation regimes.

In addition to the above Ergon Energy would like to point out that the starting point adopted by the Authority in the draft determination is incorrect, since a material error in the depreciation calculation has been included in the 2000/01 Determination made by DME. A submission has been made to this effect to DME and is attached as Appendix C. As a consequence of this error Ergon Energy revised its Statement of Corporate Intent.

The draft determination indicates that the Authority reserves the right to initiate a review in the event of a material error. The Authority, in its draft determination, should have commenced from the correct starting point of $424.4 million. This point being the current revenue cap, adjusted by the error in depreciation, resulting in a starting value for 2000/2001 of $424.4 million.

Furthermore, Ergon Energy believes that the adjusted AARR of the Authority is poorly timed in terms of overall National Electricity Market development strategies. Ergon Energy contends that the introduction of full retail competition (likely to occur during the regulatory period) ought to be a factor in the Authority's considerations. A stable pricing regime, limited only by the traditional revenue cap mechanisms of efficiency factor, CPI and pricing side constraints, is a far better environment in which to have significant market change, than one with the added complication of rapidly increasing network charges.

Finally, Ergon Energy has been severely compromised relative to Energex. Not only has Energex enjoyed higher comparative revenues for the last 4 years, it will continue to enjoy higher comparative revenues for the next 4 years in spite of the fact that Ergon Energy has additional and considerable issues to address as detailed in the earlier part of this paper. The Draft Determination indicates that the revenue requirements for Ergon

Energy and Energex are relatively similar, however the adjusted revenue paths for the two organisations are significantly different with the major impacts on Ergon Energy. Looking forward, the relative NPVs of the revenue shortfalls for Ergon Energy and Energex are $94.8m and $49.4m respectively.

The Authority has an opportunity to establish a commercially focused environment in which Ergon Energy can operate over the next four years. The establishment of the appropriate cultural signals, which break away from the previous "subsidy" mentalities, is an important aspect of the determination.

Ergon Energy seeks a review of the adjusted AARR to achieve an appropriate commercial outcome.

1.4 Conclusion

Overall, Ergon Energy is seeking outcomes in the final determination which:

- supports the major change initiatives,
- delivers improved service to customers in regional Queensland; and
- provides an appropriate commercial framework for the business.

These outcomes will ensure that Ergon Energy has completed its transition to a modern and capable entity by the end of this first regulatory period while at the same time delivering value to the key stakeholders.

Ergon Energy contends that it is not in any of the stakeholders' interests to see the transition of the business delayed.

The Authority should establish the appropriate commercial incentives for the business to deliver the change program within the first regulatory period. By providing this incentive, customers will ultimately benefit by receiving the gains in future regulatory periods.

1.5 Next Steps

Following receipt of this submission by the Authority, Ergon Energy would welcome the opportunity to further develop the proposed alternative approaches in conjunction with the Authority. We propose an opportunity to explain to the Authority the detailed working of the models that sit behind the development of the alternative approaches proposed and the assumptions made in arriving at the result.

Further Ergon Energy recommends a joint meeting between the Authority, Queensland Treasury and Ergon Energy to discuss the issues of price path and CSO regimes.

In this submission Ergon Energy has argued an alternative arrangement for the setting of the risk free rate in the WACC calculation. The Authority will need to make a determination in regard to this (and others) submission on this issue prior to the proposed date of updating the rate (proposed in the draft determination to be in March 2001). This determination will need to be communicated to the businesses, by the Authority with sufficient time to allow implementation of whatever risk management measures will be required.

2 INTRODUCTION

On 19 December 2000, the Queensland Competition Authority became the jurisdictional regulator, and published their draft determination on Regulation of Electricity Distribution. This document is a significant step in finalising the regulated revenues for the Electricity Distribution Entities in Queensland for the next four years commencing on 1 July 2001.

The draft determination has some significant implications for Ergon Energy and its shareholders and the aim of this submission is to bring to the attention of the Authority the key impacts on the business, the shareholders and customers in Regional Queensland.

This document is the submission from Ergon Energy Corporation Ltd. in response to the draft determination. The document is in four major parts:

- Part 1 – Situation Analysis, which provides an overview on the current status and change drivers in the business.
- Part 2 – Addresses the major issues facing Ergon Energy as a consequence of the draft determination.
- Part 3 – Addresses all of the other issues identified in the draft determination and generally follows the sequence of the draft determination.
- Part 4 – Appendices to the main submission including a report by Indec Consulting prepared for Ergon Energy.

PART 1 – SITUATION ANALYSIS

3 ERGON ENERGY – CURRENT SITUATION

3.1 Current State of Ergon Energy

Ergon Energy is a relatively new business and has inherited the financial and physical asset positions of its six predecessor network corporations.

In the revenue determination process with the Authority, Ergon Energy is endeavouring to ensure that the final regulatory targets are consistent with the business capabilities, service improvement initiatives, and the issues arising from the merger and restructure of the business as detailed below.

3.2 Merger Issues

As part of the overall strategic planning process, Ergon Energy is targeting the delivery of significant benefits to customers and shareholders. However it must be recognised that the business is faced with significant issues arising from the merger of the six regional distributors. In particular:

- In the core line businesses of Network and Field Operations, Ergon Energy does not have the key systems capabilities necessary to adequately manage and improve the business processes. Ergon Energy currently has a multitude of legacy systems (financials, works management, asset management, customer management) and work practices arising from the independent directions and decisions taken by the previous pre-merger corporations. To realise the benefits of the merger it has become an imperative for the business to move to single integrated systems and processes across the state. This move will deliver significant economies however it will also require significant investment and human resource. Consequently there will be a lag in realising workplace efficiencies while the new single work processes and supporting business systems are being implemented. It is important to note however that failure to invest will further delay any realisation of the potential benefits.

- Ergon Energy has been progressively reviewing the operational performance of its merged business and significant issues are emerging. In some areas, poor operational practices in design, construction and maintenance have left a legacy for Ergon Energy. This is evidenced by identified maintenance backlogs, poorly performing sections of the network and inefficient work practices. The consequential safety and performance risks are being assessed and the business is committing to the removal of any maintenance backlogs through a prioritised risk management process.

- The current level of service (quality and reliability of supply) to many of our customers across the business is inconsistent on a region to region basis and inconsistent with reasonable customer expectations. Ergon Energy is committing to significant improvements in service including Guaranteed Service Levels over the next three years. However Operating and Capital expenditure will be materially impacted.

- The business has inherited an unsustainable cost base in the area of corporate services. While it is recognised that there is a potential to reduce corporate overheads, the business is faced with a massive challenge of radically upgrading support capabilities in the finance and administration areas. This post-merger upgrade, fundamentally required to manage the business, involves considerable expenditure on information technology and other infrastructure. This will slow the benefits that may otherwise have been possible.

The challenge facing Ergon Energy is immense. Operationally, financially and service-wise, significant reform is required. The capability development phase required to address the developing market and the significant challenges of managing a large corporation that has emerged from six small regional businesses, will require significant expenditure and time. Section 14 outlines Ergon Energy's strategic plans for addressing these challenges.

It is also important to understand that Ergon Energy operates in an environment where there is a lack of appropriate commercial signals. The cost of electricity supply to regional Queensland is in excess of the money returned by way of the existing tariff arrangements (>$250M of which around $100M can be attributed to the network business). This is having major impacts on the financials of the business. It is also materially impacting on CSO payments from Treasury and limiting the ability of Government to introduce the benefits of full market contestability. The lack of policy direction is contributing to uncertainty in the strategic planning for the business.

In summary, Ergon Energy is starting from a position which is substantially behind that of a mature distribution business such as Energex, and faces significant additional challenges (regional and political sensitivities, geographical size, extensive rural networks etc) in driving the <u>quantum and pace</u> of change required throughout its business.

PART 2 - MAJOR ISSUES.

4 ONE OFF COSTS

In its draft determination the Authority did not allow the one off restructure costs. The following comments were made in relation to the non-allowance of these costs.

> *"At this time, the Authority has decided to not include an allowance for these one-off costs in the Draft Determination but will be giving this issue further consideration, particularly in light of any comments received prior to the Final Determination."*

The Authority indicated that the primary reason for disallowing the restructure costs was:

> "*Decisions regarding corporate structure and costs associated with adopting a revised structure are presumably made on the basis of the inherent benefits of the changes adopted. These benefits should be sufficient to outweigh any costs. Given the unusual nature of these events, any benefits should be retained by the DNSP through resulting out-performance of the efficiency targets."*

Ergon Energy has reviewed its restructure costs, which have been accepted by the Queensland Audit Office and now submit the revised forecasts. The forecasts have been amended to take into account more up-to-date forecasts of restructure costs. Appendix A (supplied confidentially to the Authority) shows the updated forecast. The program has been delayed due to ongoing discussions with unions and government and the timing of the state election. The delays have resulted in expenditure previously forecast to occur this financial year now to be spent in subsequent years.

It is important to understand that there is also a significant Capex program required to support the overall change initiatives. The Capex is focused on the actual business systems (eg works and asset management etc) required to support the re-engineering processes. Without the associated capital investment to the Opex, savings cannot be realised. Ergon Energy has previously provided Capex projections for the business systems area, however the overall program is currently being reviewed and additional information will be provided to the Authority's Capex Consultants over the next few weeks.

In responding to the non-allowance of the restructuring costs, Ergon Energy would like to focus on four key issues:

- Drivers for restructuring,
- Service improvements
- Quantification of savings generated from restructuring, (Appendix A)
- The asymmetry of benefits and costs.

4.1 Drivers for Restructuring

As described earlier, Ergon Energy was formed in June 1999 as a result of the merger of six distributors in regional Queensland. The six regional distributors all had individual work practices, business rules, asset management systems, safety standards, and performances.

Since the merger a number of significant issues have emerged within Ergon Energy. These issues were detailed previously in section 3 of this submission.

4.2 Service Improvements

Ergon Energy is focused on delivering significant service improvements to its customer base in Regional Queensland. However to deliver these improvements, Ergon Energy needs to substantially re-engineer its core processes and invest in enabling technologies to firstly measure the performance and secondly deliver improvements. Included in the restructure costs submissions are the following allowances for process redesign and training.

- Standardisation of Designs and Drawings ($1.9m) – Without standardisation of design and drawings, Ergon Energy will be unable to operate in a safe and effective manner.
- Establishment of Standardised Work Methods ($0.768m) – Once the standard designs and drawings are in place the development of common safe work methods would follow.
- Training staff in the use of new work practices ($24.58m) – Having established new standards and new work methods, an extensive training program to deliver the information and methodology to operational staff is essential to ensure safe working conditions and maximum network improvement from the changes.

It is forecast that $6.7m of these costs will be spent in 2000/01 with the remaining $20.5m spent in 2001/02.

The Authority did not allow the restructure costs claiming that restructure costs would have resulted in sufficient benefits (cost savings) to warrant such restructure expenditure.

The service costs identified above will not deliver significant cost savings but are required to firstly measure and then deliver network performance to a level that will satisfy consumers and regulators. A survey of customers has found that consumers would be willing to incur additional cost for improved service standards as shown in Section 14.2

As these costs are focused on delivering direct benefits to customers, Ergon Energy contends that these costs should be passed through to the customers.

4.3 Asymmetry of Benefits and Costs

The table “Funding on cash flows” in Appendix A has been derived independently of the cost submission to the Authority. In other words

Ergon Energy, in submitting increasing savings over the years, has already factored into such costs the benefits gained by reduced staff costs.

The Authority, in disallowing any restructure costs has:

- claimed this funding is a shareholder matter. The Authority is saying the shareholders (and not the customers) should pay for the restructure, however the Authority is also saying that the customer should benefit through reduced prices. This is not a commercial, nor a reasonable trade-off.
- placed the ability of Ergon Energy to deliver the savings at risk. The shareholders are placed in a difficult position – how to fund what is, in shareholder terms a 'dead investment' – a sunk cost that will never be recovered. Even a commitment to carry out this 'investment' will be constrained by the ability to fund it and any failure in Ergon Energy's ability to fund it will jeopardise the timing and quantum of the future benefits.
- removed such restructure costs from future regulatory decisions. The costs are to be incurred each year up to 2004/05. The benefits are clearly shown to be ongoing. Nevertheless, a successful restructure 'investment' will not form part of the Authority's consideration in relation to the regulatory period beginning 1 July 2005.

In summary, if no account is taken by the Authority of the restructuring required, and if the Authority's Opex targets are adopted as proposed, then the key objective of the Authority, namely, maintaining the financial integrity of the business and reducing cost without compromising customer quality requirements, would not be met.

A more detailed analysis is provided in Appendix A.

5 WACC (INCLUDING TAX ISSUES)

Ergon Energy has three major concerns with regard to the calculation of WACC in the Authority's draft determination, namely:

- the use of actual cash tax payments:
- the method for determining the risk free rate; and
- the asset beta.

These matters are addressed below.

5.1 The use of actual cash tax payments

Recent regulatory history has shown Regulators moving from a position where strong incentives were provided to improve capital, operating and financial efficiency for the period under review. Today some regulators are now concentrating only on operational efficiency, with financial efficiencies muted or non-existent. Ergon Energy believes that the Authority's Draft Decision continues this trend.

In its draft determination the Authority states…

"… At issue is whether the cost of tax calculated using the statutory rate should reflect the actual tax paid (including permanent and timing differences) or notional tax based on accounting profit. Historically, the presence of accelerated depreciation allowances has meant that capital intensive businesses such as DNSPs have benefited from significant timing differences. In the case of the Queensland DNSPs, significant tax losses have been accumulated and as such, over the current regulatory period the DNSPs are likely to pay a very low level of tax if any at all. As these timing differences will eventually reverse, it would be reasonable for this arrangement to continue into the future. The Authority supports the use of forecast cost of tax supplied by each distributor at the start of the regulatory period."

Ergon Energy argues against the use of actual tax cash flows for the following reasons:

- Price volatility caused by fluctuations in cash tax payments;
- Inconsistency between entities;
- Increased administrative requirements;
- Difficulty in forecasting tax cash flows;
- Decreased incentive to effectively manage taxation; and
- Inconsistency with other WACC assumptions.

5.2 Price volatility caused by fluctuations in cash tax payments;

Historically, Ergon Energy has benefited from the ability to calculate tax depreciation using accelerated depreciation rates. As a result, tax depreciation has typically exceeded accounting depreciation, and consequently tax payable is less than tax expense calculated on accounting profit.

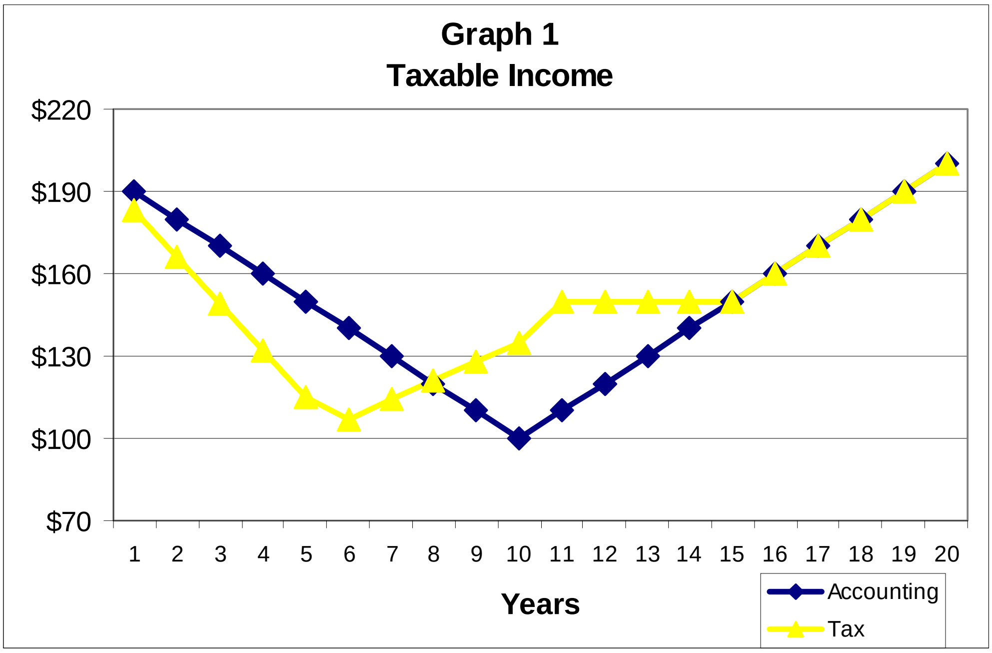
From 21 September 1999, the ability to use accelerated depreciation rates was removed. Moving forward, it is expected that tax and accounting depreciation rates will be similar, if not identical.

This will result in significant reductions in the timing differences currently generated by distributors. The existing assets which have had accelerated depreciation are aging and therefore will shortly reverse the timing difference thus resulting in an effective tax rate higher than the statutory tax rate. To illustrate this, the simple example below shows the changes in tax payments and effective tax rates as assets age.

The example is based on the following assumptions:

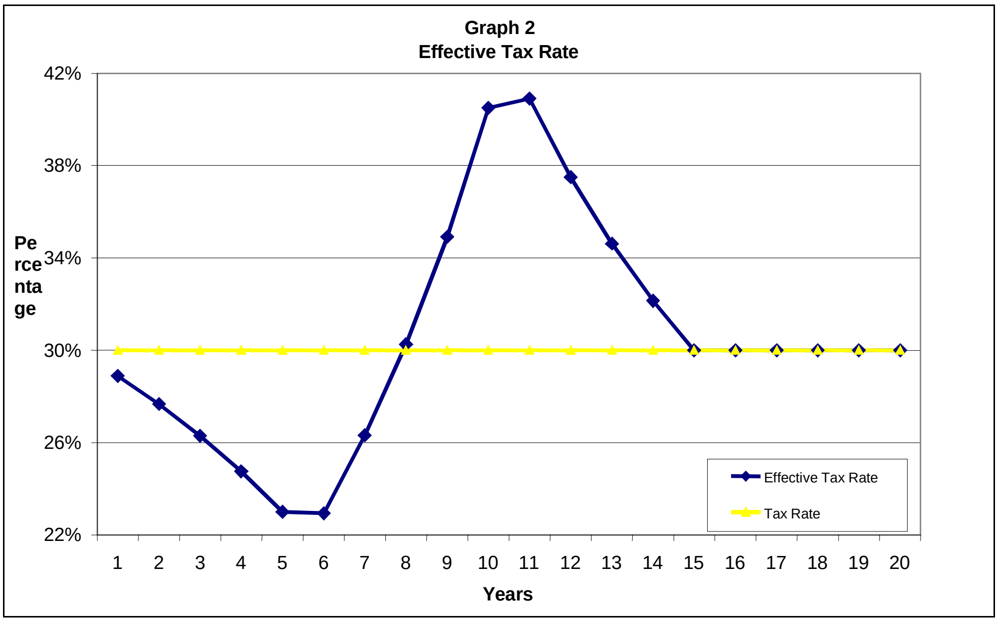
- Accounting profit before depreciation is equal to $200 in each year.
- The company originally does not hold any assets. Assets are acquired with a value of $100 at the start of each of the first 10 years.
- These assets each have an accounting effective life of 10 years. Accounting depreciation is claimed at a rate of 10%, accelerated tax depreciation at the rate of 17% and tax depreciation post 21 September 1999 at the rate of 10%.
- Accelerated depreciation is removed in year 5 of the example.
- It is assumed that no other adjustments are made between accounting and tax assets, and accounting and tax income.

Graph 1 shows the relationship between accounting and taxable income.



This graph shows that in the early years when accelerated tax depreciation is allowed, the taxable income is less than accounting income (years 1 to 8 in this example). Once all the accelerated tax depreciation has been used, the taxable income exceeds accounting income which results in higher tax payments (years 9 to 15). Once all assets that received accelerated depreciation have been fully depreciated for both accounting and tax, the taxable and accounting profits equalise (after year 15).

Observing the effective tax rate over the period of the example highlights the impact of the removal of accelerated depreciation. The effective tax rate is calculated by dividing the tax paid by the accounting profit. Graph 2 shows the effective tax rate compared to statutory tax rate.



The change in timing differences will result in significant price shocks. It is acknowledged by Ergon Energy that this is unlikely to occur within this regulatory period, but on current estimates is likely to reverse in the next regulatory period. This price shock would not be in the best interests of the distributors and the community in general. Additionally the timing of the price shock may coincide with the introductory period of full retail contestability.

5.3 Inconsistency between entities

The use of the actual tax cash flow forecasts of each entity will result in inconsistent results between entities. In the current market both Energex and Ergon Energy have carried forward tax losses and therefore there is no differential between the two entities. However, within the next regulatory period Ergon Energy and possibly Energex will have utilised all carried forward tax losses and therefore be in a tax paying situation. At this point Ergon Energy and Energex will have different tax payment profiles resulting in different revenue determinations.

The Authority noted in its draft determination a desire for there to be consistency between entities as a result of its rulings.

"The Authority is of the view that actual capital structures will change over time, and are likely to differ between entities. Adopting actual capital structures may therefore result in different inputs to the WACC model for different entities, which may be considered contrary to the desire for consistent regulation."

Therefore the question must be raised as to why has the Authority gone against this desire and used individual tax forecasts.

5.4 Increased administrative requirements

The tax regime, whether federal or state, is determined on the legal entities of the business. To meet the requirements of the Authority to identify separately the taxation position of the regulated business with Ergon Energy's network will be an administrative nightmare. This will be especially difficult with regard to separating the carried forward tax losses into regulated and non-regulated. The administrative difficulties will be increased when as part of the recent taxation reforms, entities will be able to produce tax returns on a group basis. The result of these administrative difficulties will be that the DNSPs will have to increase administrative levels to be able to produce the taxation information required by the Authority. These increased costs will either have to be funded by increased cost of electricity to consumers or decreased returns to shareholders.

5.5 Difficulty in forecasting tax cash flows

There is significant difficulty in forecasting tax cash flows for periods of greater than one year. Taxation changes occur every year due to legislation changes, new tax rulings, and new judgements. Some of the major current or proposed changes to taxation that are currently facing Ergon Energy are detailed below (in addition to changes to depreciation, that are discussed above). As these changes are yet to be legislated in a number of circumstances, a detailed technical analysis has not been performed. Rather, the discussion set out below merely considers some potential theoretical results.

5.5.1 Consolidations

Under the proposed consolidations legislation, it will be possible for group companies to lodge a single income tax return for all group entities. The Government released an exposure draft of Consolidations legislation in December 2000.

Many of the finer details of the consolidations legislation are yet to be released, however, some aspects that could give rise to tax changes include:

- The loss of the ability to group tax losses between groups that elect not to consolidate. This could jeopardise the ability to recoup losses. In some circumstances, there are restrictions on the ability to recoup losses that might otherwise be available to recoup. An entity's loss factor will determine the rate at which losses can be recouped. This has the potential to accelerate the transition into a tax paying position.
- It is necessary to determine the cost base of assets to a consolidated entity. Depending on the method used, the cost base of tax assets may be reduced below the current depreciable cost base. Once again, this could accelerate the transition into a tax paying position.

This position is exacerbated where a company has carried forward losses, as with Ergon Energy. In order to continue to carry forward losses, it may in some circumstances, be necessary to allocate a cost base to the losses. This reduces the cost base that can be allocated to depreciable assets. The alternative is to forgo the carried forward losses, and that is not economically or commercially acceptable.

5.5.2 "Option 2" – Cash Flow / Tax Value Method

Taxable income is currently calculated using concepts of taxable income and allowable deductions. These concepts would be replaced by a model based on cash flows and changes in the "tax value" of assets. Whilst some simplified examples published by the government indicate that no significant variations in taxable income would arise, there is clearly a risk that a change in the method of calculating taxable income could give rise to such variations.

The introduction of Option 2 has been deferred. However, it is understood that there remains support to introduce the measures at some time in the current regulatory period.

5.5.3 National Tax Equivalents Regime

It is proposed that Ergon Energy transition from a State Tax Equivalents Regime (STER) to a National Tax Equivalents Regime (NTER) with effect from 1 July 2001. It is anticipated that some concessions which exist under the STER will be removed. For example, contributions received in respect of assets have historically been treated as non-assessable and non-depreciable. Under the NTER, it is expected that such items will be treated as assessable income when received. A deduction for depreciation will then be claimed in respect of the contribution over a period of time. This change will bring tax and accounting depreciation into closer alignment, and accelerate the time frame within which Ergon moves into a tax payable position.

Ergon Energy faces additional difficulties in forecasting cash tax payments due to its recent formation. Ergon Energy is currently in the process of merging its previous regional operations into a single entity. The inheritance of the previous separate regional distributors is six different, accounting systems, business rules, taxation procedures, asset registers. This, together with the fact that Ergon Energy has yet to submit a tax return as a single entity, may result in significant differences between forecast and actual tax payments.

Due to the difficulties in forecasting cash flows significant differences between the actual tax paid and forecast tax payments may arise. In the draft determination these differences are to be carried forward to the next regulatory period. This may further increase the price shocks to be felt in the next regulatory period. Considering the reluctance of the Authority to pass on the price shock in its current draft determination, it is questionable whether the full adjustments to future revenue determinations will be allowed.

5.6 Removal of incentive to effectively manage taxation

The use of actual cash tax payments in deriving the regulated revenue for a DNSP will result in a removal of incentive for the DNSP to effectively manage their tax position. What benefit would be gained for the DNSP or their shareholders in reducing taxation if that reduction is then simply passed through to customers via reduced revenue?

The approach by the Authority to micro-manage the DNSPs taxation management policies differs significantly from approaches it has taken in other areas. The two primary areas where a DNSP can effectively provide increased returns to shareholders is in it capital and taxation management policies. The Authority has already recognised the importance of allowing the DNSP to manage its own capital structure.

In deciding to use a benchmark rather than actual capital structures, the Authority stated:

"…the Authority is of the view that an industry benchmark approach to determining capital structure is appropriate. Such an approach is designed to encourage financial efficiency rather than prescribe any particular capital structure, which remains the commercial prerogative of the entities".

This statement reflects the intent of the regulator to encourage financial efficiency not micro-manage the commercial prerogative of the entities. Therefore Ergon Energy recommends the use of a benchmark taxation rate to offer incentive for the DNSPs to effectively manage their taxation position.

5.7 Inconsistency with other WACC assumptions

The key variables included in the WACC calculation are:

- the risk free rate;
- the cost of debt;
- the proportion of debt funding and the capital structure;
- the market risk premium;
- equity, debt and asset betas;
- dividend imputation;
- tax rates; and
- expected inflation.

In its draft determination the Authority used industry benchmarks or standards for each of these inputs. Ergon Energy agrees with the Authority for the need for consistency in using actuals or benchmarks when calculating WACC. In its WACC derivation the Authority has been consistent by using benchmarks or standards as inputs rather than the specific inputs for each entity except for taxation.

Therefore, the Authority is inconsistent with using actual cash tax payments. Ergon argues that for the WACC to be accurate there must be consistency with the use of benchmarks as inputs. If the Authority is to continue to use the actual cash tax payments then Ergon Energy would seek leave to use their actual inputs for all the variables, in particular, the capital structure, equity and asset betas, and cost of debt.

5.8 Enhanced Regulatory Risk due to Asymmetrical Regulation

Ergon Energy has a real concern that should the Authority adopt a forecast tax cash flow, adjusted for actual tax payments methodology in its decision, then Ergon Energy and Energex will be significantly exposed to regulatory risk for the subsequent price reset. The significant risk is associated with the assumption that the Authority will apply symmetric regulatory principles to its ongoing decision. Thus if it follows an 'actual' tax cash flow methodology now, it must also follow the same methodology for the following regulatory period.

Referring to the Graph 2 above, if the Authority assumes a zero tax rate now, will it be willing to assume a 40% or higher 'actual' tax rate in the following regulatory reset process? Ergon Energy does not believe that the political and consumer realities in the following reset will allow the Authority to apply symmetrical regulatory principles. Indeed, Ergon Energy and Energex will lose revenue in the initial regulatory period, but be unable to pass through the tax payments of the next regulatory period. This is because of the anticipated reluctance of the Authority to allow a price shock. Thus overall both Ergon Energy and Energex are likely to receive less than the average tax liabilities over the next two or three regulatory periods.

The result will be that Ergon Energy will be seen by debt markets as being exposed to significant regulatory risk (or discretion) and the market will not be as forthcoming in the future over the provision of low debt premiums to support Ergon Energy's debt. Debt premiums are likely to rise, and hence the consumers in the long run will be disadvantaged through financing costs due to the regulatory decisions taken.

5.9 The method for determining the risk free rate

The risk free rate in the WACC calculation represents the return on an asset or investment with zero default risk. In practice this is generally assumed to be the sovereign bonds ie. Commonwealth Bonds. In determining the risk free rate to be used in the WACC calculation the two key issues to be considered are term and method of measurement.

In the draft determination, the Authority used 10 year Commonwealth Bonds as the proxy for risk free rate. Ergon accepts the use of ten-year bonds due to its liquidity and its wide use as a proxy.

The risk free rate will be calculated based on the 10 year Commonwealth Bond rate observed at the time of deciding the rate of return for the Final Determination. The observed rate will be the risk free rate unless there is a perturbation in the market on the day the rate was observed. If there is a perturbation then the Authority proposes to use an average rate based on the five preceding trading days.

Ergon Energy disagrees with this approach for two reasons:

- Debt Management implications and cost,
- Price shock implications.

5.9.1 Debt Management Implications

Ergon Energy feels that the use of a single day to determine the risk free rate does not allow the Distributors to effectively manage their interest rate exposure. The cost of debt is calculated by adding a debt margin to the risk free rate. For a distributor to remain interest rate risk neutral they must re-finance their debt on the date the risk free rate is set. Re-financing the greater than $2.5billion debt held by Ergon Energy and Energex on a single day would lead to significant market issues.

The market would be aware of the Authority's determination and its potential impact on Ergon and Energex's debt management. Therefore speculators will enter the market attempting to make profits at the expense of Ergon Energy and Energex. The implication of this is increased debt margins. Ergon Energy sought advice from various financial institutions including Queensland Treasury Corporation (QTC) on the magnitude of this increased margin. The average of opinions is that the debt margin would increase by approximately 40 basis points on the first instance of a regulatory rate reset. This volume margin will increase at the next regulatory rate reset, as market knowledge of the debt management implications of distributors will have increased.

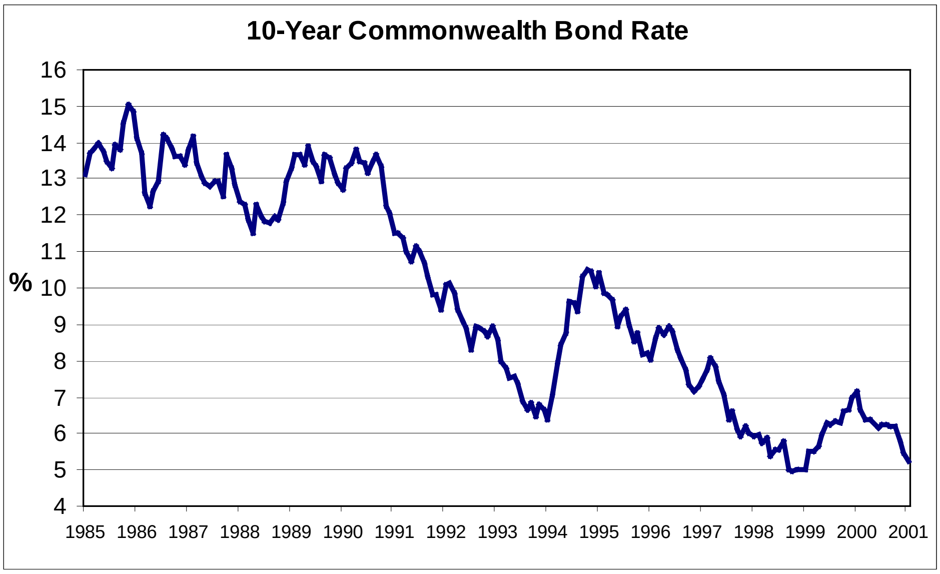
Ergon Energy and Energex both currently fund their debt through QTC. Both distributors benefit from QTC's low cost of funds and efficient debt management capabilities. Under the GOC financing rules both distributors incur a "Competitive Neutrality Fee" (CNF) on top of the debt rate achieved by QTC. This fee is to ensure that Ergon Energy and Energex meet the National Competition Policy principles, that is, they do not gain advantage from being government owned. It should be noted that the CNF does not include an allowance for loan administration costs paid to QTC. QTC has advised that an increase in administration fees of 15 points would apply to fixed rate loans compared to Ergon Energy's current debt portfolio.

If the Authority does not change its risk free rate setting policy then Ergon Energy argues that the debt margin should be increased to take into account the full debt management costs. Therefore the debt margin should increase by 55 basis points to cover increased loan administration and volume margin.

An additional debt management issue is the funding of future capital expenditure. In utilising a "current rate of the day" approach, the Authority is effectively setting the debt rate that DNSPs should fund future capital expenditure at. Interest rates are likely to move significantly during the regulatory period resulting in interest rate risk to the DNSPs. Ergon Energy requests the use of a 'collar' on the risk free rate. If, during the regulatory period, the risk free rate moves by more than 75 basis points then the WACC should be reset and applied to future capital expenditure. This will alleviate the significant interest rate risks to be borne by DNSPs for future capital expenditure.

5.9.2 Price Shock Implications

The graph below shows the 10-year Commonwealth Bond Rate over the past 15 years.



Graph 3

Graph 3 highlights the fact that the current bond rate is at historical lows. The implication of this is that any existing debt within the distributors will be at a higher rate than allowed for by the Authority in their final determination. Therefore the shareholders of Ergon Energy and Energex will receive lower returns due to higher interest costs unless all their debt is floating. This will force distributors to minimise their risks by restructuring all their debt to be refinanced at the time of regulatory resets, thus incurring the increased costs as above.

The additional issue with the risk free rate setting policy is the likelihood of future price shocks. The graph above highlights the volatility of bond rates over the past 15 years. The impact of changes in the risk free rate to the revenue determination is significant. A one percent movement in bond rate increases Ergon Energy's revenue determination by approximately 6 percent or $30m (based on 2005 asset base). This is a significant issue when the bond rate is at historical lows. Since the draft determination the 10-year bond rate has fallen to 5.255% which if applied to the 2001/02 asset base would result in a reduction to revenue of $18.3m.

The use of single rate of the day will increase the volatility of the prices to consumers. An example of this would be if bond rates were to rise to 9% at the start of the next reset. The increase in revenue would be $92.5m or 18%. This is a similar level to the current price shock that the Authority felt needed smoothing which resulted in lower returns to Ergon Energy's shareholders.

Ergon Energy believes that a more appropriate bond setting regime for long dated assets would be to use an average approach. The average should be long enough to take into account the debt structures that would be applicable to the assets being funded. A rate of the day approach is appropriate for short-term assets that are liquid. This does not apply for long-term assets with low returns. A better approach would be to take an average approach of approximately 4 years. The benefits of a four-year average are:

- Better match the debt structure of distributors
- It would cover most of the interest rate cycle thus decreasing the level of future price shocks
- Achieve the most efficient debt management procedures for distributors, thus decreasing costs to consumers.

In summary, Ergon Energy believes, for the reasons stated above, that the 'single day' method proposed by the Authority will increase Ergon Energy's debt margin by 55 basis points. Ergon Energy urges the Authority to consider using a longer-term (say four years) average rate. If the Authority does not change its 'single day' method then Ergon Energy requires an increase in the debt margin of 55 basis points, as well as the use of a 'collar' for future capital expenditure.

5.10 Equity Beta/Asset Beta

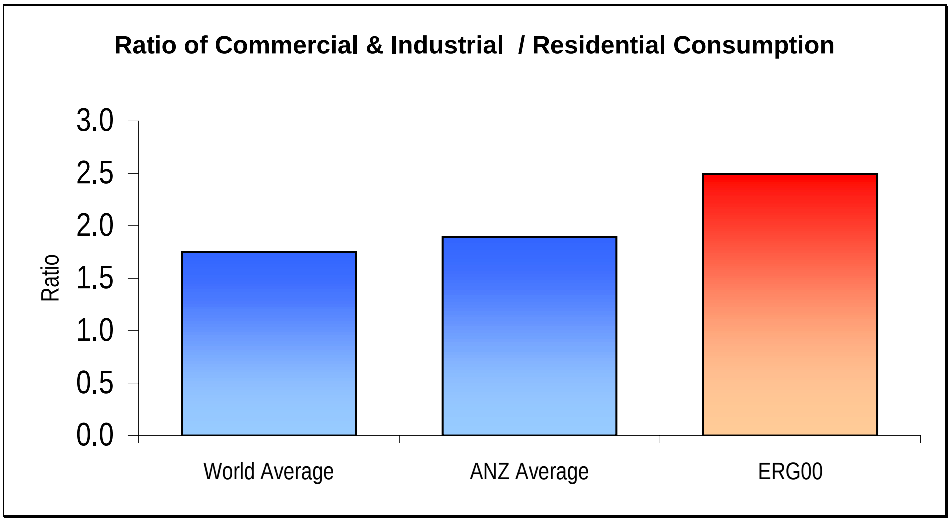
Ergon Energy is disappointed in the analysis of equity betas and the associated asset betas undertaken by the Authority. The Authority concluded (as indicated in Appendix C of the Draft Determination) that the asset beta for both Energex and Ergon Energy is 0.50, and the equity beta is 0.85.

In its deliberation, the Authority investigated variability in consumption and distribution of electricity as a possible ground for undiversifiable risk facing the Queensland distributors. The graph produced (Figure C.1) compared growth in consumption for Queensland with the nation as a whole and concluded that no risk was evident. Ergon Energy submits that any analysis used by the Authority that is based on *aggregates* misses the point. Ergon Energy believes it has a very different risk profile from that of Energex.

Ergon Energy's February 2000 submission to the Authority mentioned particular features of Ergon Energy's network. Ergon Energy stresses the following risk factors not addressed in the Authority's analysis:

- potentially stranded or under-utilised assets in a long, low-population density system,
- the proportion of high consumption mining loads (coal and gold) which are high risk (the first due to green house gas drivers where high profile mine closures have started to happen and the second due to the nature of the volatile world markets and the uncertainty of life of the ore bodies),
- the materially higher cost per customer for rural systems that greatly exposes Ergon Energy's assets to substitution.

Information supplied by UMS, submitted in Graph 4 below, shows the proportion of commercial and industrial (C&I) to residential consumption in Ergon Energy is more than 30% higher than the Australian average and more than 40% higher than the world average. Moreover when it is considered that 40% of Ergon Energy's consumption is utilised by our current contestable customers, (including coal and gold miners particularly) it is apparent that Ergon Energy's risk profile is markedly different from others.



Graph 4

Ergon Energy submits that insufficient attention has been given by the Authority to establishing whether the Queensland distributors have different risk profile.

Ergon Energy restates its requirement for an equity beta of 0.92 and an asset beta of 0.55 to better reflect the risk profile of Ergon Energy.

6 EFFICIENCY TARGET

Ergon Energy has a number of issues with the Draft Determination on Operating Expenditure and also with the TAP and PEG reports:

- The ultimate target of 30% below current operating costs is not soundly based
- The Authority has overlooked the other mechanisms proposed by TAP for closing the gap to best practice
- Timing of efficiency factors

6.1 The target of 30% below Current Operating Costs

Ergon Energy contracted Indec Consulting to provide specialist advice in relation to the TAP and PEG reports. This report is attached as Appendix B and forms part of this response to the Draft Determination.

Indec Consulting demonstrates clearly that the sheer size of Ergon Energy's service area makes it unlike any other distributor in the western world. Ergon Energy supplies to nearly all of the state of Queensland, which is 2.5 times larger than Texas and 7 times larger than the United Kingdom. Not only is Queensland large, but it has a land occupancy greater than any other Australian state, with an occupied area 36 percent greater than that of Western Australia. As the most decentralised state, with most of its people scattered along the eastern coastline over a distance of 2,200 kilometres, and with a thin dispersal of people over almost all of the vast interior, Queensland poses severe challenges to Ergon Energy in conquering distance.[1]

Indec Consulting's analysis shows that there are no high performing utilities that have similar customer density statistics to Ergon Energy. In fact, benchmarking Ergon Energy without taking energy density into account leads to some bizarre results.

For example, if we were to substitute Energex's (the benchmark) Opex costs into Ergon Energy's data for GWh, customers and km of line we get a measure of the efficient cost targets Ergon Energy is aiming at. The answers are:

Ergon Energy's Opex should be $75m if its Opex/customer is the same as Energex's, $109m if its Opex/GWh is the same as Energex's, and $609m if its Opex/km is the same as Energex's.

If we turn this into a weighted output index (0.5 GWh, 0.27 Customers and 0.23 km as per the TAP report, we get $240 million as a benchmark target. At this stage Ergon Energy's costs are $152m.

Substituting data in this manner is often done in benchmarking studies to test the results.

In short, Indec Consulting's analysis shows that the Ergon Energy network is an outlier in the developed western world in terms of service area and

[1] Facts in this paragraph are from Encyclopaedia Britannica

customer density. Furthermore, the TAP and PEG analysis do not adequately adjust for these conditions in their models.

Ergon Energy strongly recommends that the ultimate target of 30% below current costs be reassessed by the Authority in the light of Indec's report.

6.2 Mechanisms for closing the gap to best practice

TAP indicate that the gap to Best Australia Performer can be closed in a number of ways in their report (emphasis added):

"*It should be noted that the reduction in unit O&M costs could be achieved in a number of ways. Apart from the obvious way of output remaining unchanged and O&M costs being reduced by 15 per cent, it could also be achieved by* ***O&M costs remaining unchanged and output increasing by 17.5 per cent****. Consequently, normal growth in system output over several years could be expected to go part way towards achieving the target if O&M costs are held in check. It should also be noted that Ergon has a relatively poor reliability record that reduces its comprehensive output index. Again,* ***improving reliability performance would be an effective way of getting closer to the target Australian best practice unit O&M cost****."*

In the draft determination, the Authority has not considered the alternatives to closing this gap. By focussing purely on the reduction of Opex as the means of obtaining efficiency, the Authority implies that Service Quality <u>will remain constant</u>. Service quality is an important issue for our customers, and both TAP and PEG have highlighted the issue of poor service quality. Therefore, Ergon Energy strongly contends that Service Quality improvement should be included as a means to closing the gap to best practice rather than relying purely on cost cutting.

TAP also state that the gap may be closed through growth. GHD are forecasting 3% per year growth for Ergon Energy. If this holds true, modelling of the Fisher Index shows that Ergon Energy will close the gap to best practice in 6 years, without any reduction in Opex or improvement in Service Quality. By only taking half of this growth into Opex, the Authority is denying Ergon Energy the opportunity to close the gap with growth.

Under TAP's assumptions, a 15% reduction in Opex is equivalent to 17.5% growth. Substituting these into the roll on formula (ignoring CPI):

$$\begin{gathered} O\&M\ (1-x)\ (1+G) \\ = \$152m\ (1-0.15)(1+0.175) \\ = \$152m \end{gathered}$$

that is, the gap has closed and Opex has remained at $152 million in real terms.

Under the Authority's determination using half the growth:

$$\begin{gathered} O\&M\ (1-x)\ (1+G/2) \\ = \$152m\ (1-0.15)(1+0.175/2) \\ = \$152m * 0.9244 \\ = \$140.5 \end{gathered}$$

that is, $11.5m has been removed from Opex over and above that required for best Australian practice according to TAP.

Ergon Energy strongly suggests that the Authority fully explore the possibilities of using Growth and Service Quality improvements to close the gap to best Australian practice. Ergon Energy's preliminary modelling of the Fisher ideal index shows that the gap to Australian best practice can be closed in four years through growth and service quality improvements alone***, without any x factor applied to Opex***. This is further progressed in the Indec report.

6.3 Timing

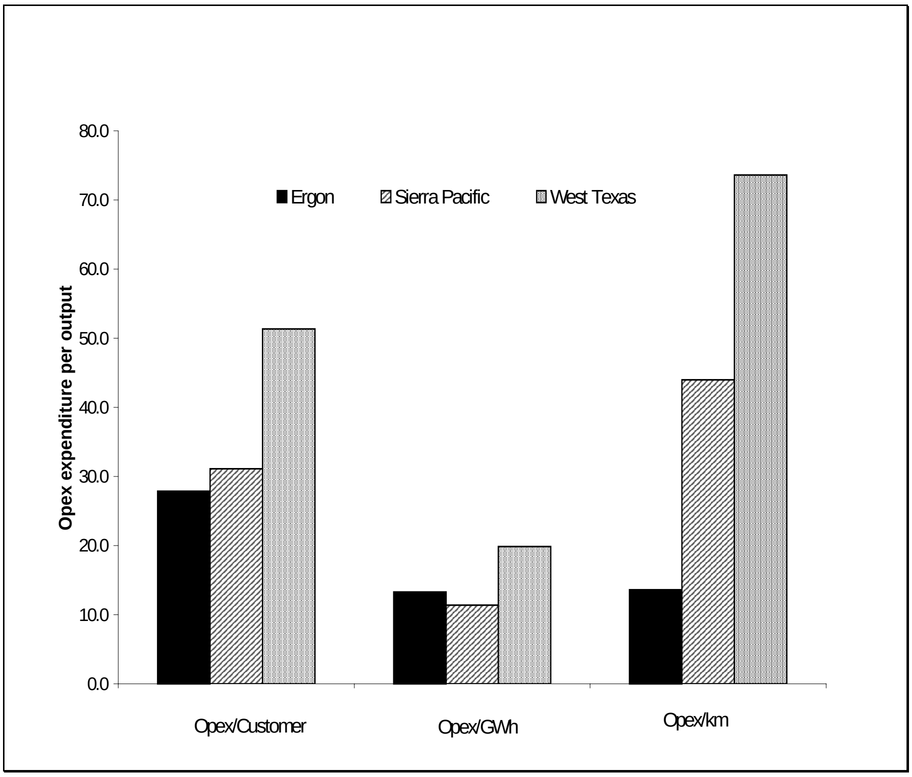
Indec Consulting also found significant issues with the timing of the efficiency factor applied to Ergon Energy. TAP and PEG failed to fully investigate where Ergon Energy is as an organisation, and to practically address the issues and challenges facing the organisation. Indec Consulting has experience in the area of restructuring and demonstrates that:

- The proposed rate of sustainability of improvements will not be at an even rate per annum (as has been demonstrated in other industries that have undertaken significant restructuring).
- In order to meet long term improvements of a 2-3% magnitude, Ergon Energy needs to undertake a major reform initiative as outlined.
- This will not produce any savings for initially up to 2-3 years.
- The asset management benefits of optimising the network will not be sufficiently in place for 3-5 years.

TAP and PEG were unable to indicate how their recommended efficiency savings may be made. Their report “Potential for Improvement in Best Practice in Electricity Distribution” surveyed three utilities for ways to make these savings. The responses were generally in line with the approaches taken by Ergon Energy and outlined in this document.

However, TAP and PEG are unable to make recommendations on where efficiency may be achieved at a sub-functional level. It seems that Ergon Energy is more efficient than the target peers chosen in their report “Achieving Identified Savings in Operations and Maintenance Expenditures – Benchmark O&M Costs”.

As highlighted in the Indec Consulting report, Graph 5 below “compares existing OPEX costs per customer, GWh throughput, and kilometre of line for Ergon Energy and its US peers. Measured against customer numbers its costs are around half those of West Texas; against line length its costs are only 15 per cent of those of West Texas, it is only against GWh that there is any comparability. The US peers supply to customers with demand levels 25 to 35% higher than Ergon Energy, providing a higher capacity utilisation and theoretically lower average costs. It would appear that Ergon Energy sets the benchmark for its peers!"[2]



Graph 5

Ergon Energy suggests that the magnitude and timing of efficiency cuts as determined by the strategies outlined in this Response are far more realistic than recommended by TAP and PEG. That is, given the current business capabilities, Ergon Energy contends that it is not realistic for it to deliver significant savings in the early years of the determination. However, Ergon Energy will deliver efficiency though the mechanisms of Service Quality and Growth. Furthermore, once common platforms have been rolled out across the organisation during the first regulatory period, Ergon Energy will be in a position to capitalise on its size and pursue world's best practice. The benefits for customers will be delivered in subsequent regulatory periods.

[2] See attached Indec Consulting report.

7 SMOOTHING THE AARR

7.1 Impacts of Option 4 Smoothing

The outcome from the proposal (Option 4) is that either the O&M for the business or the return to the Shareholders will be materially impacted. The Authority's benchmarking (and the merger and restructure issues identified above) concludes that Ergon Energy has limited capacity to reduce O&M in the immediate future, consequently a reduced return to Shareholders is the likely impact (as recognised by the Authority in the Draft Determination). The outcome is a performance level of around 4.9% in 2001/02 growing to around 6.7% over the 4 years.

This position is unacceptable to Ergon Energy because:

- it entrenches a subsidy mentality which is inconsistent with the commercial and cultural direction of the business;
- market and political perceptions of a poorly performing GOC business will limit business opportunities; (partnering, alliances, and job growth);
- it provides a disincentive to invest;
- the revenues will not support the asset valuation and therefore the shareholders may have to write down their investment in Ergon Energy; and
- the Draft Determination may set a precedent for treatment of future revenue adjustments that may result from changes to interest rates and taxation.

Ergon Energy contends that the adjusted revenues are based on a non-commercial approach to shareholder returns. Through the SCI process, Ergon Energy is committed to delivering Shareholder returns that are consistent with the value of the business and market expectations. Consequently the revenue impacts <u>will</u> be felt in the operating expenses of the business and compromise the delivery of satisfactory outcomes to other stakeholders particularly in the areas of

- Improvements in service (quality and reliability of supply) to regional Queensland; and
- Retention of jobs in Regional Queensland

Further the decision to reduce the NPV by $94.8 million seems to contradict the methodology followed by the Authority in arriving at the AARR of $476 million for 2001/2 rising to $520.3 million in 2004/5. In arriving at these initial figures, the Authority has determined what it considers to be an appropriate WACC, asset base valuation, depreciation treatment, operating expenditure level, efficiency factor and other factors that go to determining these amounts. Reducing the AARR for the first 3 years of the regulatory period seems to necessarily contradict the assumptions that were used in arriving at the initial figures.

In addition Ergon Energy is aware that there may be an inconsistency in the approach adopted by the Authority in the draft determination for

Queensland Rail. It is our understanding that an NPV smoothing approach has been used, in lieu of the straight-line approach adopted for electricity.

The Authority also states that its preferred option "shares the burden of the adjustment between the distributors (and their owner) and consumers". However, based on the Authority's assumptions of 2.5% inflation and 3% growth in demand, it appears that virtually the entire burden is placed on Ergon Energy.

The Authority states that it is concerned about the step increase between the 2000/1 and 2001/2 AARR figures and the "price shock" this will cause. However, because of the Government's uniform tariff policy and the small number of contestable customers (particularly in Ergon Energy's distribution area) the "price shock" will, in reality, mostly be felt by Queensland Treasury. The step increase will be passed on to Ergon Energy Retail who will claim a larger CSO payment from Treasury. Queensland Treasury, however, is not a Network User under clauses 6.10.3(e)(3) and 6.10.3(e)(6)(i) of the Code and consequently the “price shock” delivered to them should be ignored by the Authority in meeting its obligations under the Code.

Ergon Energy is not aware of any pre-existing government polices which state that the government owned DNSPs should accept an artificially lower return in order to minimise prices to customers. In fact, one of the fundamental planks of the competition framework established by the Queensland Government is that Government Owned Corporations should compete on a level playing field with private companies. Section 19 of the Government Owned Corporations Act sets out a number of key principles of corporatisation, one of which is clarity of objectives. Elements of this principle are that GOCs should have clear non-conflicting objectives, specific financial performance targets and any community service obligations should be clearly identified and separately costed. The clear intent of this policy is that the cost of performing CSOs should be transparent and not "blended" with other commercial activities.

The Authority's statement (at page 122 of the draft) that the reduced NPV is appropriate "given that the DNSPs' owner (the Government) has historically accepted a lower return from these businesses in order to minimise prices to customers" appears inconsistent with this policy framework. The statement is also factually wrong because, for the large majority of customers (ie. franchise customers on government mandated bundled tariffs) distribution prices have no impact on the price they pay for electricity supply.

The draft determination, if accepted, leaves Ergon Energy with limited options:

a) *Provide a lower rate of return to our shareholders over the regulatory period*. This option is considered to be unacceptable by the Directors of Ergon Energy for the reasons given above.

b) *Significantly reduce operating costs to achieve an appropriate rate of return.* This is a difficult option as the Authority has benchmarked the expenditure levels and concluded that the current level is in line with expectations for an organisation like Ergon Energy. Significant reductions in operating costs above the Authority's targets would have significant impacts on the level of service and system performance. In addition there would be implications for jobs in Regional Queensland.

Neither of the above options is consistent with Ergon Energy's stakeholder requirements. Consequently Ergon Energy seeks a change in the approach to the final determination.

Ergon Energy is currently working with Treasury to develop appropriate mechanisms to manage both the organisation's rate of return to its shareholders and the Governments exposure to CSO's. These negotiations and the eventual arrangements will be outside of the scope of the Authority's determination. It is Ergon Energy's position that the Authority should not make a determination that pre-empts these negotiations, as this is the responsibility of the shareholder both as a Government and business owner. The Authority does not have a role in determining Government policy.

7.2 Corrected 2000/01 Regulatory Determination

On page 119 of the draft determination the Authority states:

"*Finally, it appears that the Authority's regulatory depreciation (or return of capital) is greater than DME's, though the reason for this is unclear."*

The reason for this discrepancy was as a consequence in a 'material' error in the revenue determination by DME, where the depreciation component of the AARR was not based on the revised asset value used by DME but was based on the previous, non-adjusted asset value.

Further to this, Ergon Energy identified that its initial budget depreciation forecast was obviously incorrect and significantly under estimated the depreciation expense for 2000/01. This incorrect average rate used in the initial budget increases the depreciation form $125.3 million (as per the DME determination) to $147.5 million (a difference of $22.2 million). The net result of this error is that Ergon Energy's revenue cap for 2000/01 should not be $402.2 million but $424.4 million.

The Authority, on pages 35 and 36 of the draft determination, indicates that it reserves the right (as provided by the Code) to initiate a review where information provided to the Authority is found to have been false or materially misleading, or a material error made in setting the revenue cap.

Ergon Energy has made application to DME to correct this material error in the current revenue cap and a copy of this application dated 29 November 2000 is attached to the submission as Appendix C. This issue is still being pursued with DME.

The Authority, in its draft determination should have commenced from the correct starting point being $424.4 million. Below is a copy of the Authority's table 9.4 from the draft determination with the appropriate adjustments made.

Option	2000/01	2001/02	2002/03	2003/04	2004/05	NPV	Difference
	$m	$m	$m	$m	$m	$m	$m
1	424.4	476.0	491.9	506.9	520.3	1757.6	
2	424.4	452.9	483.4	515.8	550.5	1757.6	0.0
3	424.4	476.0	490.9	506.3	522.1	1757.6	0.0
4	424.4	446.6	469.9	494.5	520.3	1697.5	60.1

The table above shows what could be termed the *Amended* Unadjusted and Smoothed AARR. In general it follows the Authority's Table but Ergon Energy's recommended solution is substituted for the Authority's.

Amended Option 1 shows the Unadjusted AARR series (but with the previous year – 2000/01 set to $424.4m level as mentioned above.

Amended Option 2 shows a smoothed path finishing at the target level ($520.3m). Because of the changed 2000/2001 year, there is a different start point and therefore a different slope. Nevertheless, as with the Authority's analysis, the PV matches that of Option 1.

Amended Option 3 will now incorporate a smaller P_0 adjustment (due to the changed 2000/2001 figure. The absolute revenue levels remain at QCA levels and the PV is obviously the same.

The corrected option 4 has the following features:

- It starts at the correct starting point. This has the effect of minimising the impact of a P_0 adjustment, yet conceding the necessity to face the issue of price shock.
- It finishes at the appropriate level, with no necessity for a price shock at the end of the regulatory period.
- It offers smoothing to phase in 'correct pricing'. Real increases of 2.6% are envisaged over the regulatory period.
- It provides Ergon Energy with a Present Value of revenue flows that is closer to what Ergon Energy would argue to be the 'market' price. Nevertheless the Present Value of the shortfall is still considerable - $60 million.

Ergon Energy acknowledges that the Authority had no way of knowing about this issue. However it only becomes an issue because of the smoothing approach taken in Option 4.

PART 3 - GENERAL ISSUES.

The following sections of this submission cover Ergon Energy's comments on all of the other issues that we wish to raise with respect to the draft determination. Generally they follow the sequence of the draft determination as issued by the Authority.

8 THE AUTHORITY'S REGULATORY FRAMEWORK

Ergon Energy supports the proposed regulatory framework detailed in the Authority's draft determination. However, it is in the application of this framework by the Authority that Ergon Energy has some significant concerns.

8.1 Application of Incentive Regulation

The Objectives of the distribution service pricing regulatory regime to be administered by the Jurisdictional Regulators under the National Electricity Code requires the jurisdictional regulator to achieve:

(a) an efficient and cost-effective regulatory environment;

(b) an incentive-based regulatory regime which:

(1) provides an equitable allocation between Distribution Network Users and Distribution Network Owners of efficiency gains reasonably expected by the Jurisdictional Regulators to be achievable by the Distribution Network Owners;

(2) provides for, on a prospective basis, a sustainable commercial revenue stream which includes a fair and reasonable rate of return to Distribution Network Owners on efficient investment, given efficient operating and maintenance practices of the Distribution Network Owners;

Ergon Energy contends that the draft determination on the Regulation of Electricity Distribution is a long way from achieving the above objectives. The approach adopted by the Authority in the form of a Post-tax nominal WACC, and the treatment of taxes payable, indicate a shift towards rate of return regulation. This is contrary to the intentions of the objectives outlined in the Code which envisage an "incentive based" regulatory regime and, as a consequence, rules out the traditional rate of return regulation.

The Authority's preferred approach of adopting a constant growth path from the opening value to the final years unadjusted AARR value certainly does not provide Ergon Energy with a sustainable commercial revenue stream which includes a fair and reasonable rate of return. Indeed, it is only in the last year of the regulatory period that Ergon Energy will achieve a fair and reasonable rate of return. The Authority contends that the above approach is acceptable since the Government has historically accepted a lower return from the business. Notwithstanding the Queensland Government's previous acceptance of lower returns, the draft determination does not provide a fair and reasonable rate of return as required by the National Electricity Code.

The Authority acknowledges in the draft determination that economic regulation aims to ensure either directly or indirectly, that prices are at appropriate levels. To this end the authority correctly identifies the revenue requirements for Ergon Energy over the four-year regulatory period which will result in prices being at appropriate levels. However, the Authorities preferred approach in smoothing the DNSP's AARR is indicated to be an attempt to minimise price shocks to customers and consequently artificially holds prices down below the appropriate level determined by the Authority.

The distribution service pricing regulatory regime to be administered under Part D of the Code must seek to achieve the following outcomes:

(g) reasonable recognition of pre-existing policies of governments which are Distribution Network Owners regarding distribution asset values, revenue paths and prices;

The Authority's stated aim of attempting to reduce price shocks is obviously an attempt to satisfy this requirement. This however ignores other pre-existing government policies in relation to CSOs designed to manage the difference between the true cost of supply in the Queensland market and the current Government policy of Maximum Uniform Tariffs to franchise customers. Only 324 (ie. six one hundredths of one percent) of Ergon Energy's total customer base of 544,863 have entered the contestable market and are directly exposed to the price increases resulting from the determination with the remaining 544,539 customers being charged the Maximum Uniform Tariff.

Ergon Energy further contends that the introduction of full retail competition likely to occur during the regulatory period ought to be a factor in the Authority's considerations. A stable pricing regime, limited only by the traditional revenue cap mechanisms of efficiency factor, CPI and pricing side constraints, is a far better environment in which to have significant market change, than one with the added complication of rapidly increasing network charges.

8.2 Pass though Opex items

In the draft determination the Authority reserves the right to initiate a review where information provided is found to have been falsely or materially misleading, or a material error was made in the setting of the revenue cap, or there is a change in ownership that may materially change the revenue requirement. It was further indicated that aside from these events, the Authority only expects to make within period adjustments where major exogenous and unforseen events impact significantly upon the returns of the regulated business. The Authority also indicated that it would consider immediate pass through for:

- Changes in taxation; or
- Other major changes in government policy.

In our previous submission in response to the issues paper titled "Electricity Distribution - Framework for Regulation", Ergon Energy recommended a Revenue Cap approach that included an allowable cost pass through mechanism. There are a significant number of issues that are already on the horizon and there is likely to be significantly more during the regulatory period. The following is a list of current issues (this is not necessarily an exhaustive list) that may have an impact and would need to be considered during the regulatory period.

(a) Revised or New Standards and Legislative Changes

- The National Standards Commission is introducing changes to the Weights and Measurements Act that will impact on utility businesses. Additional costs associated with these changes will need to be accommodated during the regulatory period.
- The Queensland Government is currently reviewing the appropriate electrical safety legislation. Depending on the outcome of this review, additional regulatory obligations could be placed on the distribution businesses, which are not included in the data supplied to the Authority as part of this review.

(b) Code Changes

- The National Electricity Code Administrator (NECA) is currently conducting a review of Network Performance standards under the National Electricity Code (NEC). This has the potential to impose requirements on the distribution businesses, additional to the Authority's requirements. No allowance for any changes in this area has been included in our current submission.

(c) Market Changes

- The introduction of Full Market Contestability will impact on the costs of the distribution businesses. As and when the systems and processes that are required for the successful operation of full retail competition are known, we will be in a position to provide these to the Authority.
- The current NECA review on integrating the market and network services has the potential to add significant operational costs to the distribution businesses. Ergon Energy will continue to lobby for a position that minimises the cost impacts on our business. The final outcomes of this review are likely to be implemented during the regulatory period.

(d) Government Policy

- Changes in Government policy are always likely to impact on the costs of the distribution businesses. As these are difficult to forecast, no allowance has been included in our submissions to date.

A process for dealing with pass through costs needs to be defined before the start of the regulatory period.

9 PRESCRIBED SERVICES

Ergon Energy acknowledges the Authority's obligations under clause 6.10.4 to determine which, if any, distribution services are prescribed distribution services and therefore subject to economic regulation under the code. In the Authority's final determination on "Electricity Distribution: Determination of Prescribed Services" dated September 2000 and repeated in the draft determination, the requirements of clause 6.10.3 (6) (iv) of the NEC have been overlooked. This clause states:

6.10.3 The regime under which the revenues of Distribution Network Owners and Distribution Network Service Providers (as appropriate) are to be regulated is to be administered by the Jurisdictional Regulators in accordance with the following principles:

(6) provide reasonable certainty and consistency over time of the outcomes of regulatory processes having regard for:

(iv) relevant previous regulatory decisions made by authorised persons including:

A the initial revenue setting and asset valuation decisions made by a government at a time at which that government was a Distribution Network Owner in the context of industry reform pursuant to the Competition Principles Agreement;

B decisions made by Jurisdictional Regulators and any regulatory intentions previously expressed; and

C decisions made by ministers under jurisdictional legislation.

It is clear from the above that the Authority must have regard for the previous regulatory decisions and intentions expressed by the Department of Mines and Energy as well as decisions made by Ministers under jurisdictional legislation.

On the 29 June 2000 the Minister for Mines and Energy wrote to Ergon Energy advising of his approval of the revenue arrangements for the period 2000-2001. Specifically this approval stated (emphasis added):

I wish to advise that I have approved a maximum allowable revenue cap in respect of ***Ergon Energy regulated assets*** *for the one year period 2000-20001.*

As indicated in our letter to the Authority dated 20 November 2000 this did not include the following assets and services:

- Non-regulated assets. These relate to specific assets where commercial arrangements have been negotiated with the customer and the final arrangements have been approved by the regulator of the day.
- Recoverable works. The revenue associated with this service is intended to recover costs only and has been previously excluded from the revenue cap.

- Other external contract revenue, which includes revenue and costs for services such as hi-load escorts, Responsible Person costs, services listed in schedule 7 – part 3 of Electricity Regulation 1994 and contestable metering services.
- Asset disposals. This primarily includes the disposal of motor vehicles and the costs exceed the revenues. These probably fall outside of the prescribed services determination.

Ergon Energy believes that the Authority has not fully taken into account all of its obligations under the code on this matter in its draft determination. Consequently, Ergon Energy contends that the previous regulatory intentions of the jurisdictional regulator and decisions of the Minister need to be taken into account and that as a consequence, all of the assets and services previously regarded as excluded should remain excluded.

10 CAPITAL BASE

Ergon Energy is pleased that the Authority has endorsed Depreciated Optimised Replacement Cost (DORC) as the appropriate basis for valuation. Ergon Energy agrees with the Authority that such a valuation is "consistent with that which could be ascribed in a competitive market". Nevertheless, despite the framework of a DORC valuation, there are concerns felt within Ergon Energy that the benefit, in terms of competitive price signals, are lost if ANY of the relevant key factors; DORC, appropriate rate of return and operating costs are not delivered. In other words, a transition price path has the effect of rendering ineffective ANY or ALL of the key building blocks.

10.1 Adjustments to Capital Expenditure

Ergon Energy views with concern the interim decision by Authority to amend the anticipated capital expenditure, pending an independent assessment of the reasonableness of the amounts provided. While it is noted that such a decision is a preliminary one, the basis of the decision - connecting (even loosely) each year's depreciation with the level of expenditure, shows a misinformed approach to the nature of capital expenditure. While it is true that SOME expenditure is of a replacement nature, much of the capital expenditure is based on customer requests, augmentation to supply, as well as safety and reliability. These factors are clearly NOT directly related to the existing depreciation level.

It is considered a more responsible and less arbitrary approach, given the time constraints, to allow the expenditure, pending the independent assessment. The arbitrary level adopted by the Authority could have the effect of prejudicing the assessment by the Authority's consultants by indicating a pre-determined level of expenditure.

Further still such an approach – having proposed capital expenditure levels 'approved' by the Authority – increases the likelihood of micro-management by the Authority or gaming by the DNSP. Ergon Energy believes a more appropriate approach is for Ergon Energy to develop a capital investment protocol that it provides to the Authority as a basis for future capital investments. Once that protocol has been approved by the Authority then the ongoing regulatory process would involve light handed 'audit' – ensuring that appropriate processes are carried out in the ongoing capital investment process.

10.2 Further research by the Authority on Easement Valuation.

Ergon Energy has noted that the Authority, having rejected the independent valuer's Optimum Deprival Value for easements, proposes to carry out further work on the most appropriate long-term approach to valuation. This further work is to include research on using CPI adjustment to historical capital cost. Ergon Energy would like to know the timing of such planned research, and its possible impact on the current process.

11 DEPRECIATION

Ergon Energy agrees with the Authority's draft decision *"that asset consumption should be recognised through depreciation charges and that a straight line pattern of depreciation be adopted". Ergon Energy also agreed with the Regulator when he "accepted the effective lives of asset classes proposed by GHD/Arthur Anderson and applied these to the optimised replacement cost of those assets".* However Ergon Energy believes the Authority has effectively departed from its own decisions in its calculation of depreciation under the building block approach.

11.1 Depreciation on Non-System Assets

Ergon Energy has advised the Authority of the apparent error in the GHD/Arthur Anderson asset valuation. For system assets, the valuer follows a process where Replacement Cost is estimated first and then that valuation is 'optimised' and finally 'depreciated'.

Due to the nature of the non-system assets, the valuer has relied on the accounting (written-down) value, and used that value as the Depreciated Optimised Replacement Cost (DORC). This is considered by Ergon Energy to be an appropriate practice. Unfortunately no attempt was made by the valuer to estimate an equivalent Optimised Replacement Cost (ORC) to match the DORC. Instead the DORC number was used as both the ORC and the Replacement Cost.

The effect of such a decision is to limit the amount of depreciation calculated (under the Authority's model the depreciation is calculated by dividing the ORC by the system life).

Ergon Energy has suggested to the Authority that an appropriate valuation for ORC is the accounting value and provided the Authority with that information.

The Authority has yet to decide on this matter, which is believed to have an increase in depreciation of over $19 million. Ergon Energy considers the approach suggested is the most appropriate and requests an inclusion of this amount in the Annual Aggregate Revenue Requirement.

11.2 'Ageing' of Assets

As stated above, the Authority has accepted the data incorporated in the valuation. The effective life, the age and the optimised replacement cost were applied to derive the depreciated optimised replacement cost. (In cases where there are multiple assets in any category, averages (that is average life and average ages) were used. This is clearly a demonstration of a method that aligns with the Authority's decision to adopt straight-line depreciation.

In its modelling of depreciation throughout the evaluation period, the Authority has developed an 'ageing' factor, whereby each successive year, the asset base is deemed to be reduced by a factor of one divided by the effective life. (This means that the asset base for a 40-year asset for the first year is the initial value, the second year 39/40ths of that value and the third 38/40ths of the value, etc.) The thinking behind the ageing formula is to allow for the progressive expiry of assets that are deemed to have been acquired uniformly, over the number of average years' life of that asset. The uniform expiry concept is used in the absence of age profile data for each category of asset.

Ergon Energy believes that this method is flawed and adds unnecessary complexity to the modelling. Specifically Ergon Energy believes:

- The acceptance of the valuers' DORC (straight-line), when combined with the Authority's ageing methodology (reducing balance), creates a mismatch that means that the asset or group of assets will never be written out of the regulatory register. This may be considered by the Authority to be of no moment if their focus is a short-term period. Nevertheless Ergon Energy believes that this step is not a good precedent.
- Ergon Energy has aged profiles on all assets that would allow precise calculation of depreciation on each age grouping within each asset category. This would remove the need for the use of an ageing formula as a proxy for the age profile.

It is considered that the appropriate middle course is to use the average lives for each asset grouping as if it were the actual life of a single asset. This will provide a logical answer (one that will have the asset written off) and yet not require a massive explosion of data in order to calculate depreciation. The use of average life will mean that overall the individual profiles of the assets are matched.

12 OPERATING EXPENDITURE

In its draft determination, the Authority states "…*where DNSPs forecast significant increases in Opex over the regulatory period, the Authority expects the DNSPs to demonstrate the soundness of such forecasts, particularly in light of the Authority's efficiency study.*" Indec Consulting's report addresses the soundness of the efficiency study. This section demonstrates the strategies on which its operating forecast is based.

Ergon Energy has a strategic plan that pursues an aggressive Opex profile, dependent on one off restructuring costs and strategic capital works, while at the same time increasing service quality.

Ergon Energy's cost reduction proposals are notable in that they will occur within an environment forcing an increase in the underlying level of O&M expenditure.

12.1 Increases in the underlying recurrent level of O&M expenditure

12.1.1 Increased risk and legal liability exposures

The competitive environment and recent public focus on energy systems failures have focused company directors on their legal exposure in terms of the delivery of energy services. Recent ACCC statements about penalties for substandard performance and for breaches of the TPA requirements governing consumer protection have exacerbated this. The recent publicity of electrical accidents and the consequent focus on electrical safety along with proposed changes to expand the role of the distribution businesses is also likely to add to the potential legal exposure of company directors if not managed appropriately within the business.

This has resulted in a greater focus and a more disciplined approach to preventive maintenance requirements in order to mitigate risk exposures. This problem is common to all utility suppliers in Australia and has impacted on their underlying cost structures.

Regulatory recognition has been given to this issue most recently by ORG in the decision of the VicGas where the risk Beta was increased resulting in a higher WACC in recognition of the increased risk profile arising from the Longford Gas disaster.

12.1.2 The continuing development of Industry Standards

The requirements of continuously developing industry standards and guidelines impose costs on the electricity distribution business. The following is not an exhaustive list but gives examples of some of the compliance and risk issues that have or are emerging. It is expected that more compliance issues will arise in the future as existing regulations develop and become onerous, and new regulations arise.

a) Workplace health and safety

- Legislation has impacted the way linesmen work at heights both on poles and in substations. This has added to costs both in the provision of new climbing equipment and by slowing the rate of work.

- There are also Work Place Health and Safety issues with transport and disposal of hazardous waste. Management of these issues involves considerable documentation and is a significant cost.

b) Australian Standards

- Compliance with street lighting standards for luminance will require more lights installed at the expense of the local council but maintained by Ergon Energy. Also, maintenance of the light output to 70% will add costs by impacting on replacement programs.
- Compliance with AS3891.2 (marking for low level flying) adds costs due to increased inspection and management costs.

c) Environmental

- Compliance with environmental requirements and community expectations for tree clearing in sensitive areas adds costs due to more careful and closer clearing.
- New Legislation on the disposal of hazardous materials and chemicals has added costs due to extra procedures and disposal restrictions of hazardous chemicals. PCB disposal could be of the order of $100,000 per year.
- Management of the spread of noxious weeds has added to costs.

d) QESI Guides

- Changes in the requirements for protective earthing has resulted in earthing installations that were considered safe previously are now at risk. Additional costs are required maintain earthing records, additional testing regimes required to seek unacceptably high earths, and corrective costs to fix unacceptably high earths.

e) Other issues

- The requirement to notify property owners prior to entry has required one additional FTE in Capricornia region alone.
- Native title issues and cultural heritage involves considerable additional route acquisition costs.
- There are new costs associated with building approvals that were previously exempt.
- There is a general increase in preventive and repair/replace maintenance due to ageing population of 40+year old assets in non-aggressive areas and 20-30+ year old assets in aggressive environments.

12.1.3 Impacts of Government decisions on labour costs

The general increase in labour costs over the last four years are as follows:

1997/98 – 3.5%

1998/99 – 3.9%

1999/00 – 3.8%

2000/01 – 3.8%

The cost increases are embedded in Enterprise Bargaining Agreement outcomes, which have been significantly impacted by government intervention in negotiation of wage settlements. As a consequence labour costs have moved at a rate well in excess of CPI.

An analysis of the labour hours by task indicates in fact an overall reduction in labour hours, however the increase in per unit labour costs have outstripped the efficiency gains delivered to this point. The additional costs to distributors above a CPI movement is estimated to be around $2M over the last two years.

12.1.4 Removal of CSOs

Up until June 1998 the government reimbursed the distribution corporations for the cost of electrical inspection and related work necessary to maintain public safety standards. From 1 July 1998, the financial responsibility was transferred to each corporation. The impact was an effective annual reduction in income of around $1.85M to the regional distributor.

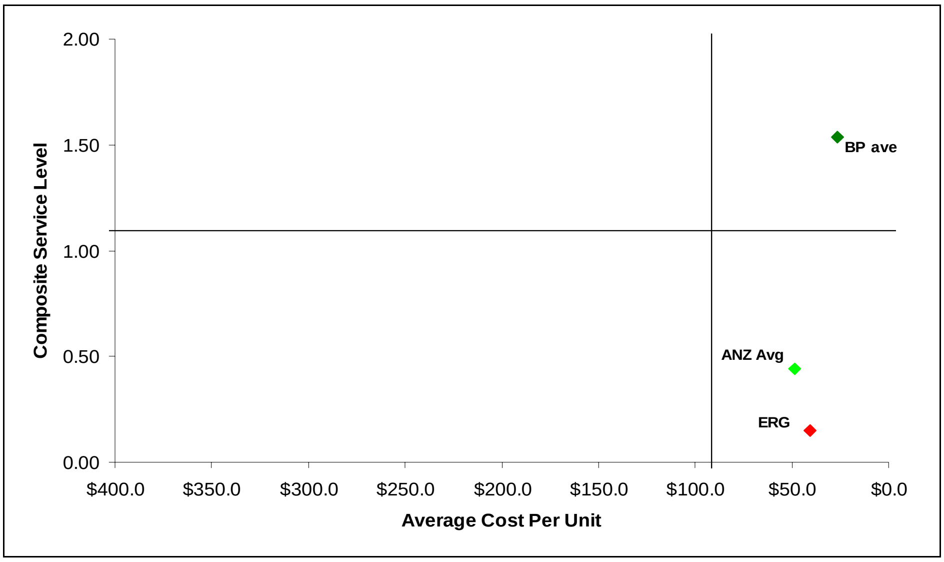
No offsetting consideration was included in the previous revenue caps.

12.2 The requirements for strategic investment

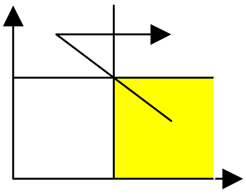
The challenges and environmental factors facing Ergon Energy have been outlined in previous sections. The following section outlines the strategic investment requirements to address these challenges.

In the past, the regional distributors had little in the way of structured “maintenance management” programs and there was little consistency or focus on preventive maintenance activities. As a merged organisation, Ergon Energy reviewed in detail its asset management and maintenance strategies. The outcome has been the deployment of disciplined and programmed preventive maintenance activities consistent with safety and performance benchmarks.

Ergon Energy engaged UMS to assist in formulating its strategic plan for management of the Network. Figure 5-3 below shows Ergon Energy as a low cost - low service asset manager when compared to ANZ average and world’s best performer (BP) average. Asset management service level is a composite of Return on Asset, SAIDI and system performance utilisation.



Graph 5 - Asset Management performance versus local average and BP



To achieve the best practice (top right) quadrant, UMS have identified the need for key strategic investment to improve service levels followed by a longer term cost reduction focus. This requires the deployment of new systems/capabilities that can deliver high service at low cost. UMS identify the types of investment that can move a company in this direction as:

- New systems/capabilities that can deliver high service level at low cost
- Strategic alliances with other firms
- New technology adoption

In general for Ergon Energy, the key areas for improvement have been identified as system automation, integrated customer information systems, works management and asset/facilities management. The TAP analysis and Indec Consulting's report has also confirmed this approach.

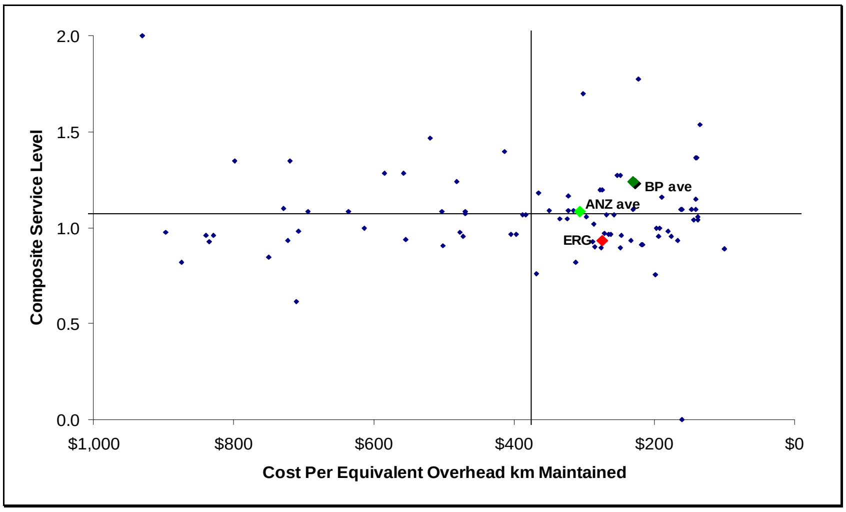
Ergon Energy's initial focus will be to consolidate the business through the development of appropriate and uniform asset management strategies, processes and support systems. This consolidation will then provide the platform for savings on a number of fronts:

- some savings will be realised with the adoption of internal best practices for the whole corporation
- greater process automation will result in less manual work and rework
- better load and system information will allow the system to be driven harder resulting in increased utilisation and greater return on assets
- better asset information will allow optimal lifecycle management of assets
- better defect information will allow optimal and targeted preventive maintenance expenditure resulting in lower reactive maintenance and better service

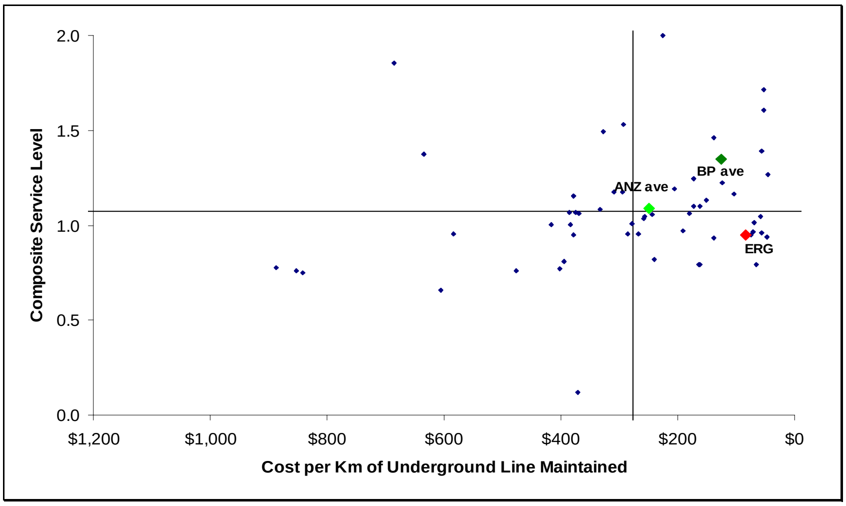
- better asset information and systems will allow the integration of asset management routines and the bundling if defects for correction
- information systems on urban trees will enable better management of tree pruning contracts and result in less outages caused by vegetation
- outage systems will enable detailed root causes of outages and targeted preventive maintenance to reduce outages

The implementation of these systems will take some time. Their effect will be a reduction in Opex through a more targeted and effective maintenance and asset management strategy. To reduce outages, there will be a shift in emphasis from reactive to pro-active maintenance. The effects of this will also take time, but eventually there will be a reduction in fault call expenditure and an increase in network reliability.

The following graphs (6 and 7) show OH maintenance and UG maintenance as being low cost but low service functions for Ergon Energy.

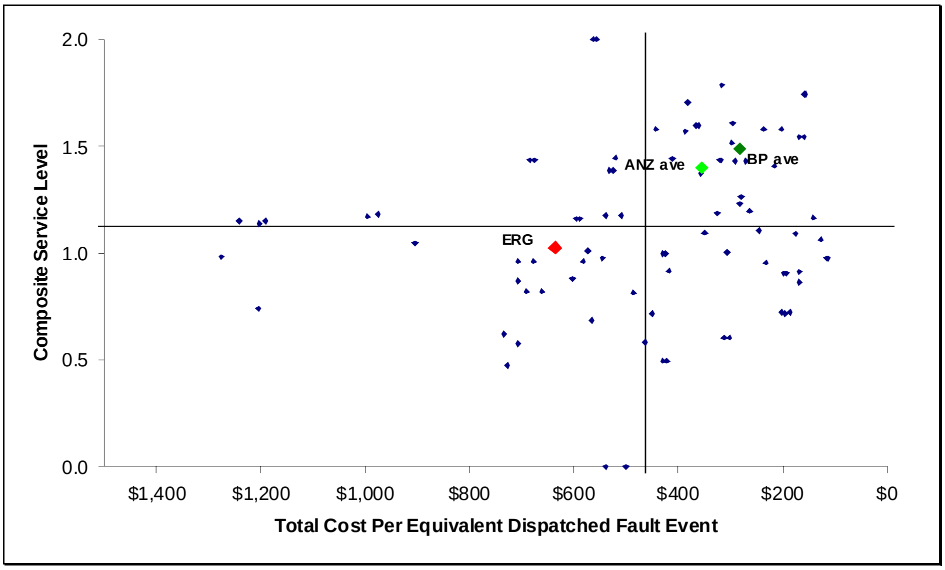


Graph 6



Graph 7

As discussed above, Ergon Energy's investment in asset management systems and maintenance systems will target and optimise the planned maintenance to increase service levels and reduce fault call costs. Activity and expenditure in the planned overhead maintenance area may increase for a time before reducing. There will be a lag between the investment in this area and the reduction of fault call expenditure and associated increase in service quality.



Graph 8

Graph 8 shows Ergon Energy as being high cost with average service levels in relation to fault response. Long travel distances place Ergon Energy at a disadvantage in Fault Response, but there are still gains to be made. Although there is limited scope to reduce the cost per fault event, Ergon Energy's approach is to reduce the number of fault events, and reduce the response time for each fault event.

13 INDIVIDUAL DISTRIBUTION TARIFFS

13.1 The Role for Side Constraints

13.1.1 References for Contestable Customers:

Ergon Energy notes the Authority's statement on Page 124 that:

"The side constraint on existing contestable customers is only intended as a transitional measure during the Authority's first regulatory period as, in general, it is considered that larger customers (current contestable customers) do not require the protection of the regulator."

Ergon Energy supports this concept with clarification that the reference to "current" and "existing" "contestable customers" means customers who, at the date of commencement of the Regulatory Period are "eligible to become contestable" as defined under the Electricity Act and Regulation.

13.1.2 Determination on Side Constraints

Ergon Energy notes the boxed determination statement on page 125:

"The Authority proposes to adopt a side constraint on network tariffs of CPI plus 5 percent for existing contestable customers and CPI plus 2 percent for residential customers."

Ergon Energy understands the need for side constraints to address rate shocks. In its submission on Network Pricing Principles, Ergon Energy stressed that there needed to be in place a mechanism that allowed for the correction of gross pricing errors.

Moreover it is possible under the Authority's proposed side constraints for Ergon Energy to be faced with circumstances where Ergon Energy could not be able to reach the level of the revenue cap. Consider the circumstance where there is the loss of a major customer, in conjunction with an overall decline in throughput. Ergon Energy may well require an increase beyond the stated levels simply to recover its revenue.

It is considered that, if the Authority persists with a relatively steep price path, (caused by the straight-line smoothing approach adopted), the potential difficulty described above may be exacerbated.

Ergon Energy suggests that the words be amended to clarify the customer classes in the following way:

"The Authority proposes to adopt a side constraint of CPI plus 5 percent for the distribution component of network tariffs for all customers. The exception to this will be a side constraint of CPI plus 2 percent on the distribution component of network tariffs for residential customers when they become contestable."

Ergon Energy suggests that the determination clarifies that the side constraints apply to the movements in prices following the initial price setting by the distributors for 2001/2002 year.

Ergon Energy also notes that side constraints are applicable only to the DUOS component of tariffs (ie. tariffs that are "bundled" and include a pass-through of the relevant TUOS charge are not subject to a side constraint on the quantum, but rather only the DUOS component).

13.2 Approval of Network Pricing Principles

Ergon Energy notes the Authority's boxed statement on Page 133 that it has decided not to apply Part E of Chapter 6 of the Code.

Ergon Energy is supportive of this concept in that this approach is consistent with our "Network Pricing Principles" submission of 25 August 2000 Page 12:

"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."

Ergon Energy notes however, that the Authority can, and will, utilise mechanisms other than the Network Pricing Principles to manage efficiency drivers.

Ergon Energy notes the Authority's boxed statement on Page 134 that requires DNSPs to address how their pricing methodologies meet economic principles.

Ergon Energy contends that methodologies relating to the economics and practicability of network pricing are still evolving and therefore Ergon Energy will work with the Authority to develop a Pricing Principles Statement that satisfies the requirements of the Authority, within the timetable in the Draft Determination.

14 SERVICE QUALITY

14.1 Measures Reporting

Ergon Energy met with the Authority and Energex on February 13, 2001 to finalise the specification for service quality measures reporting. This specification appears in Appendix D.

This specification is a comprehensive yet realistic set of measures to report against.

MAIFI is of prime importance to Ergon Energy as momentary interruptions can be irritating for domestic customers or halt processes in industrial customers. As MAIFI is technically more difficult and expensive to record, only one of the previous legacy organisations had commenced deploying equipment and systems to record transient interruptions. To implement MAIFI as an Ergon Energy wide measure the following program is required:

a) Currently feeder MAIFI is measured on the Capricornia system. Extending this functionality to the rest of Ergon Energy's SCADA enabled systems (about 300 feeders) would cost approximately $150,000. This can be ready to be operational by July 2001.

b) Extending feeder MAIFI functionality to the remainder of Ergon Energy (approximately 600 feeders) would require the installation of a supply detection device at the start of each feeder at a cost of $1000 each. Estimated cost is in the order of $600,000.

c) Extension of MAIFI functionality to feeder sections throughout Ergon Energy would require the installation of approximately 2,400 such devices for a total cost of $2,400,000.

There is also a significant ongoing O&M cost associated with the implementation of the system and management of data. A significant cost (not included above) is also required to implement a system to manage the data on this large scale.

These costs have not been included in submissions to the Authority to date. The estimated costs for the implementation of MAIFI over the coming regulatory period is

MAIFI Implementation Costs	2001/02	2002/03	2003/04	2004/05
Opex	$100k	$100k	$100k	$100k
Capex	$1.7m	$1.7m	$0	$0

A full project plan and firm costs will be submitted to the Authority in time for inclusion in the Final Determination

It is proposed that the measure of energy not supplied should not be used, as it requires a significant program of implementation as well. This measure relies on meter demand information requires which is currently not available in Ergon Energy and would require capital investment to implement. The value of this measure on a system wide basis is questionable.

It is proposed that data at the feeder level be provided for worst performing feeders only in each category. Ergon Energy will work with the Authority to define how the worst performing feeders will be determined before June 01.

Ergon Energy believes that the monitoring of customer feedback should be the prime measure of power quality. Customer perceptions in this area are important, and even if a real voltage quality situation does not exist, a customer perception of poor quality is as much a concern as actual poor supply quality and needs to be managed.

This measure is also a widely used measure and provides the best option for comparative performance once normalised by the number of customers connected to the system.

Ergon Energy believes that there is little value in only monitoring the over voltage events as described. Most problems on the network relate to undervoltage steady state conditions. Ergon Energy believes that all voltage related complaints should be reported, not just over-voltage.

Appendix D describes the reporting framework for quality of supply.

Real time technical monitoring of the system is seen by Ergon Energy as a tool for managing the network and less suitable as a comparative measure. As a tool, the network service provider will itself determine the best steady state and transient voltage and time thresholds for exception reporting to make the data meaningful and manageable. This technical data would then be used to drive down the number of customer complaints.

Ergon Energy's approach currently is to carry out regular Network analysis audits to identify potential problems. In conjunction with this, devices that monitor steady state voltage would be placed to monitor the identified trouble spots on feeders.

Ergon Energy recommends that Ergon Energy's GSL service standards be monitored and reported. The implementation of customer service measures is costly and complex and it is best to limit them to the GSL measures set up by the corporation.

Current GSLs relate to

- New Connections
- Planned Interruption notification
- Street Lights
- Hot Water
- Trees and Overhead Powerlines

Ergon Energy has adopted segmentation into Urban, Rural and Remote as defined by ERU. For comparative purposes, it may be prudent to give consideration to the segmentation adopted by the Victorian businesses. That is, Urban, Short Rural and Long Rural. A further category may be required for the Queensland situation for extra long feeders to enable comparative reporting.

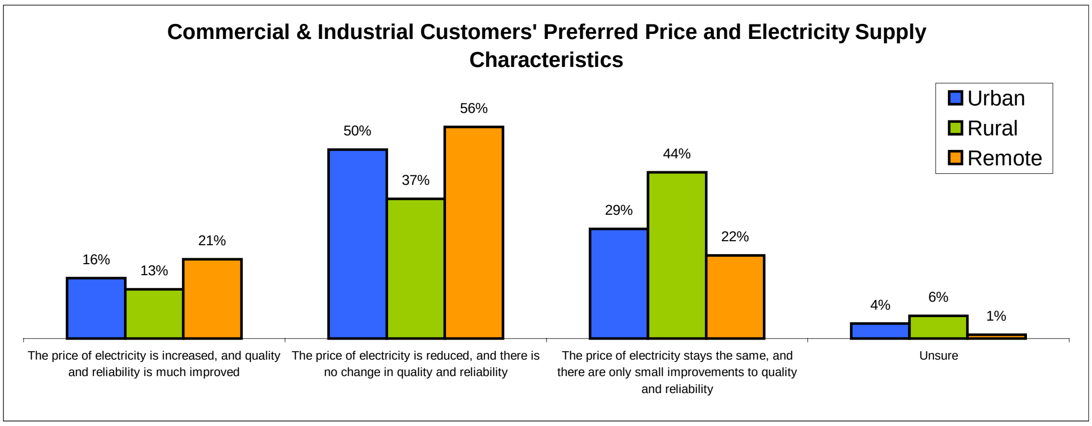
The advantage of this segmentation is that it splits rural feeders according to their length, which is the main determinant of feeder performance provided all maintenance issues have been addressed. Customer density as per the ERU rural and remote categories attempts to model equipment density, which also has an impact on performance. However, for two feeders with similar customer density the longer feeder will always perform worse.

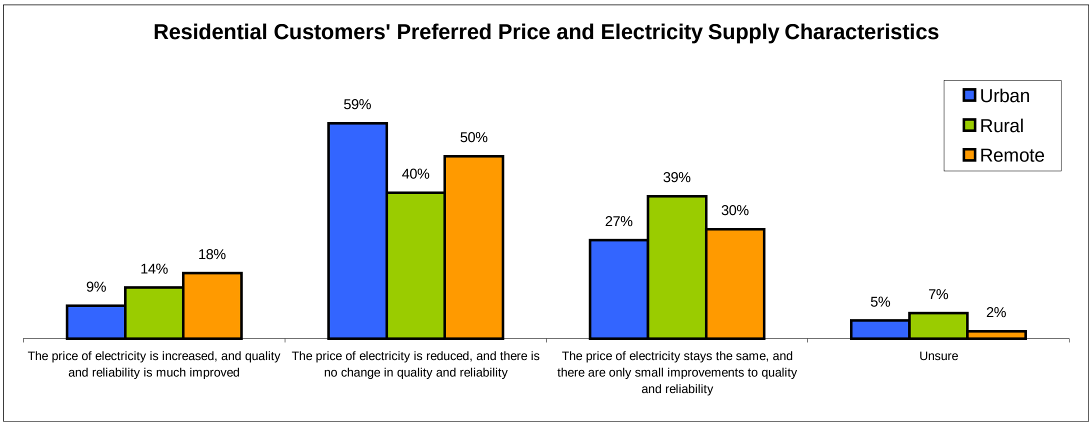
14.2 Customer Survey Results

To assist with Ergon Energy's planning and in support of this submission, Ergon Energy commissioned some customer survey work to test a value proposition to customers of improved quality and reliability for an increase in price of electricity.

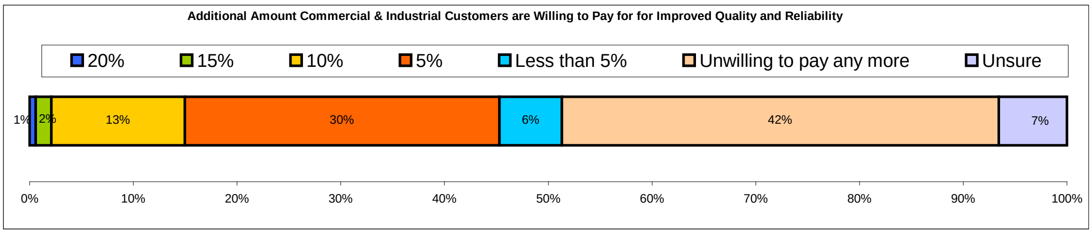
When initially questioned customers did not appear to have quality and reliability of supply issues as top of mind. However, when questioned further both rural and remote customers rated too many outages as their number one issue with price as their second issue. Urban customers rated price as their number one issue in front of outages.

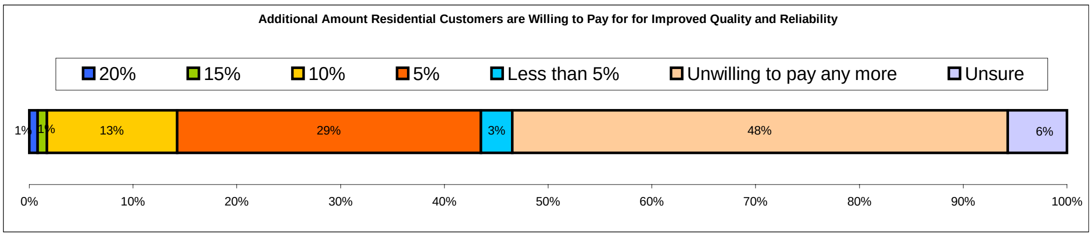
Further analysis indicated that only slightly in excess of 1/3 of rural customers (37% of commercial & industrial and 40% of residential customers) expected prices to decrease with no change to the current levels of quality and reliability.





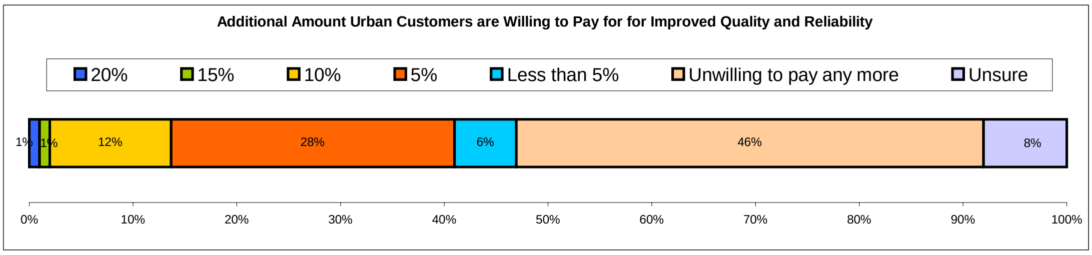
Customers where further asked how much extra they would be prepared to pay for improved quality and reliability. Just over half (51%) of commercial & industrial customers and close to half (46%) of residential customers nominated amounts ranging from 1% to 20% that they would pay extra for improved quality and reliability.

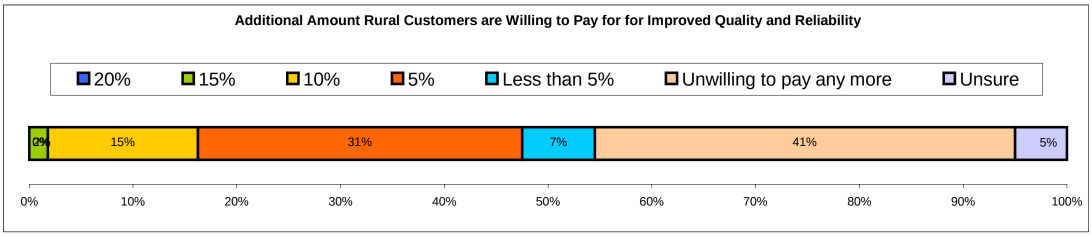


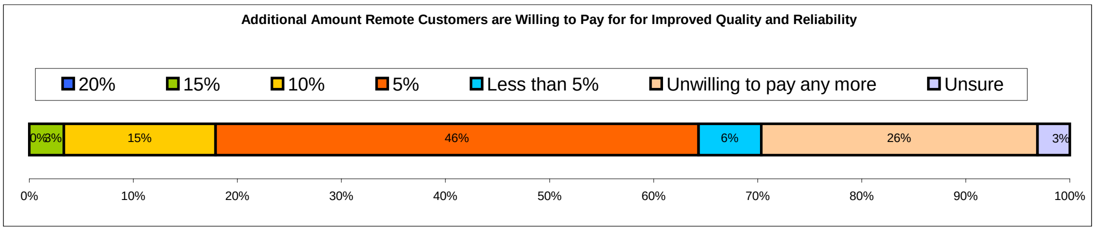


The most popular percentage, selected by about 30% of both customer types is 5% extra.

Around 30% of both Urban and Rural customers are willing to pay 5% more for improved quality and reliability. Almost half (46%) of Remote customers are prepared to pay 5% extra. In addition, 12% to 15% of customers across the three categories would pay 10% more.



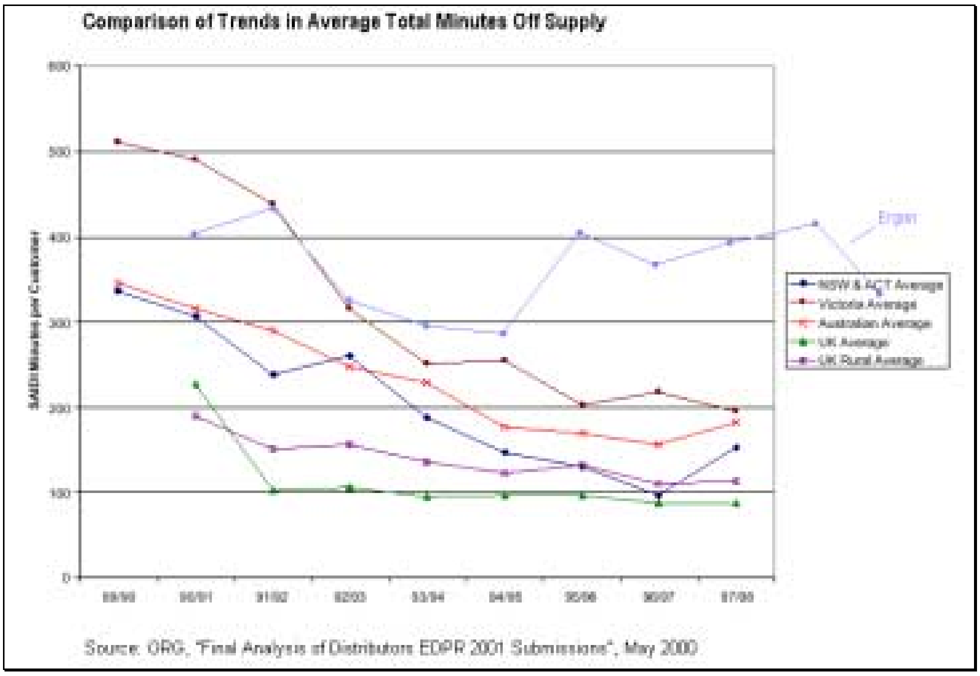




Ergon Energy concludes from the above that Service Quality is of sufficient concern to customers to warrant strategic Operational and Capital expenditure into the future to bring reliability into line with customer expectations.

14.3 Organisation Strategies to Address Reliability

Before the amalgamation, only some of the Corporations were able to provide the resources to have a specialised focus on reliability. There were very few true reliability improvement plans and most regions had no targets for SAIDI, SAIFI or of a red feeder concept. The most each realistically could do, was to comply with Electricity Reform Unit draft targets let alone improve reliability to benchmark levels. As shown in Graph 9, the small investment base and scarcity of operational resources focussed on reliability resulted in little if any improvement in reliability figures.



Graph 9

The graph shows Ergon Energy's estimated performance when compared to trends in reliability (SAIDI) of other distributors. An improvement trend is evident in the other disributors plotted, but there is no corresponding downward trend for Ergon Energy. Both TAP and PEG reports raised service quality as an issue for Ergon Energy. As a customer focussed organisation, Ergon Energy is committed to improvement in Service Quality and sees this as a prime driver over the next regulatory period. Consequently, Ergon Energy in its restructure has a primary focus on network performance.

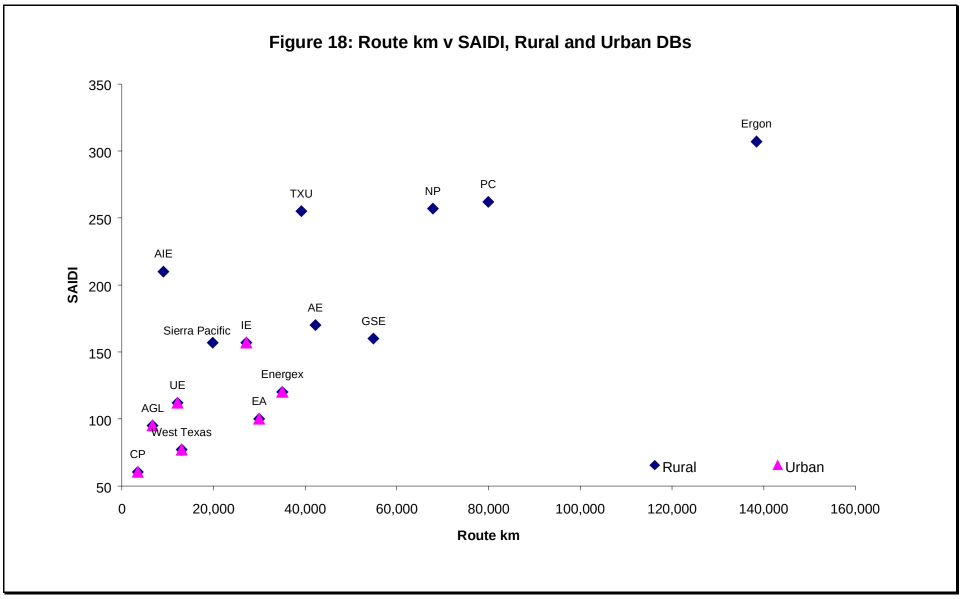
The new Network Group structure is being established with a Process focus. A Network Performance Manager has been appointed to drive significant reliability improvement. His accountabilities include:

- Network asset performance activities to ensure that the reliability and quality of electricity supply of the network complies with Stakeholder and code requirements.
- Network data and information systems for the Network group including the development and implementation of common systems for asset management and system performance measurement.
- Reporting on key performance indicators for the Network group.
- Other process streams - line assets, substation assets, planning and development, network operations

14.4 Service Quality Targets

With the new structure and focus in place, Ergon Energy has committed to significant reliability improvement of its Network. However, at this stage, a cost/reliability value function has not been developed for Ergon Energy's network, so the impact of reliability strategies is unknown. Our assessment of where Ergon Energy's SAIDI should be is around 260 mins. This figure was determined by using best practice targets from Victoria for our customer breakdown of Urban, Rural and Remote. This does not factor in the nature of the network, however. Network modelling and Graph 10 below show that feeder length has a significant impact on reliability.

Independent advice from SKM states that achieving this target requires "an annual capital spend on genuine (primary purpose test) reliability and quality of supply initiatives and projects of between $12.5m and $16m over the period 2000/01 to 2004/05."[3]



Graph 10

14.5 Service Quality Regime

Ergon Energy agrees with the Authority's assessment that it is not possible to establish an incentive-based service quality regime. Such a scheme would require at least 5 years of validated data to smooth out the environmental variations occurring from year to year. Consistent data collection in Ergon Energy has commenced in January 2001. Ergon Energy recommends that the most appropriate mechanism for service quality incentives should be comparative reporting in the short term.

However, due to Ergon Energy's operational commitment as outlined above, it is considered reasonable for the Opex target to reflect the intended improvement in Service Quality as outlined in Section 6.

[3] Ergon Regulatory Consultancy Reliability and Quality Improvement CAPEX Plan October 2000 SKM

15 COMPLIANCE MONITORING AND REPORTING

Ergon Energy considers that the proposed monitoring and reporting regime proposed by the Authority adds significant regulatory compliance costs to the business. These have not been included in operating expenditure forecasts provided to the Authority. If the Authority continues to proceed with this approach then Ergon Energy reserves its right to submit these revised costs.

15.1 Penalties for Non-Compliance

Ergon Energy is cognisant of its obligations to comply with the Authority's Determinations and acknowledges the Authority's intention to focus on "preventative" measures to ensure compliance and monitoring of compliance.

Ergon Energy considers the Authority's four principal compliance aspects of conduct and performance to be reasonable. Ergon Energy views the preventative measures and monitoring approach, conducted in good faith by all parties, to be reasonable and conducive to achieving sound outcomes.

Ergon Energy notes the Authority's statement that should it become aware of a material breach of one of its Determinations it would refer the matter to NECA. Ergon Energy submits that in the event that the Authority considers referring a material breach of a Determination to NECA, that prior to such a reference occurring, the Authority be committed to advising the DNSP of the matter, and allowing the DNSP reasonable opportunity to respond and resolve the matter.

15.2 Monitoring and Compliance Objectives

Ergon Energy acknowledges the Authority's view that comprehensive information disclosure of DNSP's compliance status is necessary. However Ergon Energy submits such disclosure should occur at pre-determined intervals.

With respect to the Authority undertaking such activities as it considers necessary to "satisfy all parties" that DNSPs are complying, Ergon Energy does not think it reasonable that DNSPs should be subjected to ad-hoc disclosures to "satisfy all parties".

There is a risk that without some reasonableness test first having been applied by the Authority, DNSPs will be exposed to an unquantifiable level of expenditure and resource commitments in managing such requests.

15.3 Possible Role for Further Conduct Rules

Ergon Energy is supportive of the Authority's assessment to not develop additional Conduct Rules.

15.4 Ring-Fencing Compliance

Ergon Energy notes that the Authority's requirement in the Draft Determination for DNSPs to "submit for the Authority's approval a compliance program that is consistent with AS3806:1998" is new, more onerous, and in addition to the requirements previously published in the Ring-Fencing Guidelines (paragraph 15).

The Ring-Fencing Guidelines simply required DNSPs to "establish and maintain appropriate internal procedures". However the Draft Determination now introduces the additional obligations of AS3806.

Ergon Energy is of the view that our letter to the Authority dated 30 November 2000 met the requirements of the Authority's determination on Ring-Fencing in that it detailed our program for compliance and is the approach we have followed since that date.

Ergon Energy accepts that Ring-Fencing Compliance in accordance with AS3806 is achievable in the longer term. However, because this introduces compliance elements that are much broader than stipulated in the Ring-Fencing Guidelines, the Authority must allow a corresponding timetable to phase in a Ring-Fencing Compliance Program which is consistent with AS3806.

The Draft Determination appears to be silent with respect to the due date for DNSPs to "submit for the Authority's approval a compliance program that is consistent with AS3806: 1998". In view of the complex number of elements necessary for AS3806 compliance, Ergon Energy submits that a date on or after 31 August 2001 would be reasonable.

With respect to DNSPs providing the Authority with a "compliance report that conforms with AS3806", there is some ambiguity as to the Authority's intention. Ergon Energy interprets the Authority's intention to be that DNSPs must submit a compliance report, but that the DNSPs are not obliged to achieve "certification" to AS3806 by a relevant body (eg. QAS, NATA).

The Authority's requirement that DNSPs establish a "compliance committee" is also somewhat vague. Ergon Energy contends that the Audit and Legal Compliance Committee (a sub-committee of the Board of Directors) is the appropriate committee to review compliance programs within our company.

Ergon Energy considers that a specific Ring-Fencing Compliance Committee is

- unnecessary;
- inconsistent with our other business compliance approach;
- replicates the functions of the Audit and Legal Compliance Committee; and
- would impose additional administrative burden in terms of costs and resources.

With regard to the DNSPs obtaining audit services from an auditor "who has been approved by the Authority", Ergon Energy is unclear about the process to be followed, the timing of the required audits and whether the Authority has pre-determined criteria which must be met for auditor selection. Ergon Energy submits that suitable auditors should be proposed separately by each DNSP, and the Authority's approval is obtained following a selection of a suitable auditor.

Ergon Energy notes the Authority's timetable for submission of a Ring-Fencing Compliance Report to be due annually on 30 October. Ergon Energy is supportive of this approach.

15.5 Monitoring Actual Behaviour and Performance and Regulatory Information and Accounting Guidelines

Ergon Energy is cognisant of its obligations to provide the Authority with information.

With respect to the Authority's comment that it "believes there are significant benefits from Australian Regulators standardising information requirements". Ergon Energy is in agreement with this concept, provided the data requested is a reasonable requirement to be gathered and reported. The danger is that national approaches can result in a situation where the 'highest common denominator' prevails. Such an outcome is a real possibility and so the derivation of the data required should be considered carefully, particularly to its relevance.

Further, Ergon Energy believes that not only should Regulator's requirements be aligned, but also statutory audit requirements, particularly with regard to financial reporting.

16 QCA'S APPENDIX D "REGULATORY ACCOUNTING AND INFORMATION GUIDELINES"

In the section that follows, Ergon Energy shows that implementation of the Accounting Guidelines requires adherence to a 'critical path'. Necessary precedents that need to be in place include:

- Prescribed and excluded services (and their associated assets and costs) approved by the Authority
- Cost Allocation Methodology approval by the Authority
- Consequential changes to the Chart of Accounts and accounting processes following on from the two steps above.

Ergon Energy believes that it will not be possible to provide accurate information in relation to the year ended 30 June 2001 because of the fact that these matters cannot be finalised until the latter part of the year.

16.1 Effective Date for the Guideline

Clause 2.8.2 states that "when finalised, this Guideline will apply to all Regulatory Accounting Periods ending on or after 30 June 2001, and that Clause 2.8.3 states that "For all substantial revisions to this Guideline, an effective date will be nominated, which is expected to be not less than six months prior to the end of the Regulatory Period".

Ergon Energy contends that since the end of the last Regulatory Period (ie. 30 June 2000 under DME's jurisdiction), the introduction of the Guideline amounts to a "substantial revision" of the new Regulator's requirements. Also there is a great deal less than six months notice between when the Guideline is finalised and 30 June 2001.

Therefore, Ergon Energy does not think it reasonable to commence application of the Guideline until the Regulatory Accounting Period after 30 June 2001.

Ergon Energy proposes that "transitional arrangements" be adopted by the Authority for the Regulatory Accounting Period ending 30 June 2001 where partial reporting alignment can be achieved.

A submission of unaudited regulatory financial statements is proposed for the period to 30 June 2001, which would provide sufficient information for benchmarking purposes. As stated elsewhere, this would need to follow finalisation of matters regarding cost allocation methodology and excluded services. The limitations of the existing chart of accounts would have to be accommodated, and consequential changes made to commercial systems.

In further support of Ergon Energy's position, it is contended that, since the Regulatory Accounting Period ending 30 June 2002 aligns with the Authority's 1st Revenue Cap term, it is logical to align DNSP's reporting requirements to that term.

16.2 Chart of Accounts

Ergon Energy is continuing to refine its accounting and reporting systems to meet the changing organisational needs that arose as a result of its formation on 30 June 1999.

On 1 July 2000 Ergon Energy adopted a new accounting system, Oracle, which involved the migration of information from six separate accounting systems with different Charts of Accounts inherited from the predecessor distribution corporations.

Ergon Energy's current Chart of Accounts produces individual codes for regulated and non-regulated activities and segregates most revenues, costs and assets. Moreover, Ergon Energy's Chart of Accounts currently does not capture all the information required to prepare full regulatory accounts.

However it is possible to prepare separate segment P&L statements for major items. Many assets and liabilities will need to be allocated between segments, and until this is done, we shall be unable to prepare segment balance sheets and statements of cash flows.

16.3 Prescribed/Excluded Services

Ergon Energy will need to finalise the process regarding the status of assets which were historically "unregulated" and are now proposed to be "prescribed services", prior to finalisation of the Chart of Accounts. Only when this process is completed (ie after application by Ergon Energy, and consideration and decision by the Authority) will Ergon Energy be able to finalise the Chart of Accounts.

16.4 Aligning Regulatory Reports

Ergon Energy's existing reporting for either management or statutory purposes does not align with the Authority's stated requirements.

It is expected that Ergon Energy's Oracle financial system will need to be redesigned to capture the necessary information.

Ergon Energy considers that there will be considerable difficulty in reporting and reconciling information if there is not alignment of regulatory and accounting policies and treatments (eg. asset valuations; treatment of restructure costs; etc).

16.5 Additional Audit Criteria

Ergon Energy considers that it will be exposed to additional audit costs and longer audit timeframes due to the additional information capture and reporting requirements set out in the Guidelines. Ergon Energy will seek to include the extra costs of regulatory compliance as part of its operational expenditure recovery.

No allowance for these compliance costs has been included in the 2000/01 and ongoing operating expenditure budget previously submitted to the Authority.

Ergon Energy has commenced discussions with the Queensland Audit Office in order to estimate the cost of, and to confirm their ability to conduct the regulatory audit.

Ergon Energy contends that this uncertainty supports our argument that the Guidelines should commence for Regulatory Accounting Periods <u>after</u> 30 June 2001.

16.6 Format of Regulatory Statements

Ergon Energy proposes that a joint consultation committee be established comprising the Authority, the DNSPs and the Queensland Audit Office in order to agree a standard format and content of the regulatory financial reports required by the Guidelines and for statutory purposes. Ergon Energy considers that a standard format will lead to greater consistency and comparability of results, and will facilitate an easier audit process, thereby reducing compliance costs.

Specific matters that require clarification include:

- the process to reconcile asset valuations for accounting and regulatory purposes, including increases in values for inflation, without introducing the need for separate asset registers;
- the necessity of inclusion of statements of cash flows for each DNSP segment;
- the requirement for tax effect accounting each DNSP segment; and
- the degree of disclosure in the Regulated Accounts of items required in the Statutory Accounts.

PART 4 – APPENDICES.

Appendix A – Revised Restructure Costs (Supplied confidentially to the Authority)

Appendix B – Indec Consulting Report

Appendix C – Application to DME for Revenue Cap Adjustment

Appendix D – Service Quality Measures Specification

APPENDIX A (CONFIDENTIAL) – REVISED RESTRUCTURE COSTS

(This section supplied confidentially to the Authority.)

APPENDIX B – INDEC CONSULTING REPORT

APPENDIX C – APPLICATION TO DME FOR REVENUE CAP ADJUSTMENT

PO BOX 308,
Rockhampton
Queensland
4700

F A C S I M I L E

ATTENTION: Tim Peisker	**PAGE:**
COMPANY: Electricity Reform Unit	**DATE: 29 November 2000**
FACSIMILE: 3222 2410	**Ref:**

SUBJECT: 2000/01 REGULATORY DETERMINATION

FROM Terry Effeney
Business Development Group

Telephone (07) 3228 7687

Facsimile (07) 3228 8255

Tim,

I refer to my previous correspondence regarding the 2000/01 revenue cap determination in which I advised that there were outstanding issues which required attention.

I am writing again to seek your approval for our GUOS (Generation Use of System) target for 2000/01 and to bring to your attention an issue relating to our depreciation which has a material impact on the overall revenue cap. As a consequence I am seeking approval for the inclusion of a revised depreciation number in the revenue cap for 2000/01.

1. GUOS Determination

The data sent to ERU as part of our submission provided the following figures.

(x$1000)	Budget 00/01
Asset Base	46721
Depreciation	4200
OPEX	25985
ROA	3182
Revenue Cap	33367
ROA%	6.81%

These numbers are consistent with the information used in determining the DUOS revenue cap and I advise that Ergon Energy is currently targeting the recovery of the revenue cap detailed above. I request confirmation from ERU of the GUOS numbers for 2000/01.

It must be understood that the actual GUOS costs are reviewed annually as part of the Overs and Unders arrangements to ensure that recoveries match the actual costs.

2. Depreciation (Return of Capital)

The allowance for depreciation (return of capital) in the 2000/01 determination was consistent with the original Ergon Energy data submission. The previous issue raised in correspondence related to the fact that no consideration had been given to the significant revaluation index adjustment that arose as a result of the independent revaluation exercise carried out at 30 June 2000. The $125.3M included in our cap is therefore based solely the non-adjusted asset value. Ergon Energy has moved to address the impacts of this by deciding not to take the re-valuation onto our books until the end of the financial year.

However a more significant issue has arisen as part of our review of the depreciation issues.

The depreciation data provided as part of our ERU submission was based on our budget projection for 2000/01. At that time Ergon Energy's financial systems were still evolving and the budget preparation was undertaken using the accounting and fixed asset systems of the six former regional distributors. Due to the lack of a central fixed assets system it was decided that the best method to calculate depreciation was to use a high level calculation. An average depreciation rate was calculated based on an analysis of the six regional distributors' fixed asset systems. This analysis determined that the average depreciation rate to be used was 5.25%. This depreciation rate was then applied to the opening Written Down Value (WDV) of the assets plus capital expenditure for the year to derive the depreciation expense. The result for regulated assets was a depreciation expense of $125.3m.

Subsequent to the calculation of the budget, Ergon Energy has implemented a new central fixed assets system. This new system has the capability to forecast depreciation at an individual asset level, thus negating the errors caused by using an average depreciation rate. The system not only calculates depreciation on existing assets but also calculates the depreciation on expected capital expenditure. The new system was run based on actual closing fixed asset balances as at 30 June 2000 and original budgeted capital expenditure. The result for regulated assets was a depreciation expense of $147.5m.

The increase in depreciation from a budgeted amount of $125.3m to $147.5m is due to the incorrect average rate used in the initial budget. To verify the accuracy of the new depreciation forecast an analysis of the 1999/00 financial results was undertaken. The WDV of regulated assets, excluding Land and Work in Progress, as at 30 June 2000 was $2,043.2m. The depreciation expense on regulated assets was $129.9m, this equates to an average rate of 6.36%. If this 6.36% rate was applied to the forecast WDV of regulated assets at 30 June 2001 ($2,324.8m excluding depreciation for the year), the resultant depreciation expense forecast is $147.9m. The slight difference between the depreciation forecasts is due to mix variations in classes of assets.

The initial budget depreciation forecast is obviously incorrect and significantly underestimates the depreciation expense for 2000/01. The 5.25% average depreciation rate used to calculate the budget is significantly below the actual average rate for 1999/00 of 6.36%. The error is further highlighted by the fact that the depreciation for 1999/00 of $129.9m is higher than the initial depreciation budget for 2000/01 of $125.3m. This indicates an error as the forecast for 2000/01 will be significantly higher than the prior year due to capital expenditure.

Therefore as a result of this error it has been decided to

- amend the SCI and Corporate Plans for the amended depreciation forecast, and
- seek inclusion of the revised depreciation figure in the revenue cap for 2000/01.

As the change in depreciation is of a material nature and will significantly impact of the EBIT position of the business, I am writing to you requesting the inclusion of the revised depreciation number in our revenue cap for 2000/01.

Ergon Energy would be pleased to meet with you to discuss the issues surrounding the GUOS and depreciation issues.

T Effeney
GENERAL MANAGER BUSINESS DEVELOPMENT

APPENDIX D – SERVICE QUALITY MEASURES SPECIFICATION

Definitions

Interruption

An interruption is an event causing a loss of electricity supply to customers and has the following attributes:

- as a minimum includes the operation of high voltage or low voltage fuses at a distribution transformer ie does not typically include a loss of supply to an individual customer
- is reported as starting when remote monitoring equipment signals the loss of supply, or where monitoring equipment is not installed, when the customers first report the loss of supply
- is of greater than 1 minute duration

A momentary interruption has a duration of 1 minute or less.

Interruption Categories

Interruptions are reported to have occurred under the following categories.

Distribution Network	Interruptions within the DNSPs network
Exceptions	Interruptions within the DNSPs network where at least 5% of the customers in the DNSPs geographical area are affected by widespread storms and flooding or other natural disaster.
Transmission	Interruptions within the Powerlink network
Generation	Interruptions due to generation deficiency normally resulting in load shedding

Feeder Geographic Categories

The following categories apply to the whole of a distribution feeder, and not sections of it.

CBD	A feeder supplying the Brisbane and Surfers Paradise central business districts characterised by a wholly underground mesh configuration
Urban	A feeder which is not a CBD feeder, with a connected load density greater than 0.3MVA/km
Short Rural	A feeder which is not a CBD or urban feeder and has a total route length less than 200km
Long Rural	A feeder which is not a CBD or urban feeder and has a total route length greater than 200km

DATA FIELD	DEFINITION	REPORTING PERIOD
Reliability Measure		
SAIDI Whole of Network	• Separately reported as Distribution System, Exclusions, and Transmission and Generation • The Distribution System SAIDI to be further separately reported as CBD, Urban, Short Rural and Long Rural • The Distribution System SAIDI to be further separately reported as Planned and Unplanned • Does not include momentary interruptions	Quarterly
SAIFI Whole of Network	• Separately reported as Distribution System, Exclusions, and Transmission and Generation • The Distribution System SAIFI to be further separately reported as CBD, Urban, Short Rural and Long Rural • The Distribution System SAIFI to be further separately reported as Planned and Unplanned • Does not include momentary interruptions	Quarterly
CAIDI Whole of Network	• Separately reported as Distribution System, Exclusions, Transmission and Generation • The Distribution System CAIDI to be further separately reported as CBD, Urban, Short Rural and Long Rural • The Distribution System CAIDI to be further separately reported as Planned and Unplanned • Does not include momentary interruptions	Quarterly
MAIFI Whole of Network	• Each Distributor will provide QCA a detailed plan by 30 June 2001 for the timely public reporting of this measure within the current regulatory period • Reported for Distribution System only • The Distribution System MAIFI to be further separately reported as CBD, Urban, Short Rural and Long Rural • Includes only the successful reclosure of circuit breakers in zone substations where SCADA equipment is installed	Quarterly
SAIDI Worst Performing Feeders	• Applies to the 11kV feeders falling outside low reliability thresholds to be mutually agreed between the Distributors and QCA by 30 June 2001 • Includes Distribution System, Exclusions, and Transmission and Generation interruptions • Includes planned and unplanned interruptions • Does not include momentary interruptions	Annual
SAIFI Worst Performing Feeders	• Applies to the 11kV feeders falling outside low reliability thresholds to be mutually agreed between the Distributors and QCA by 30 June 2001 • Includes Distribution System, Exclusions, and Transmission and Generation interruptions • Includes planned and unplanned interruptions • Does not include momentary interruptions	Annual
CAIDI Worst Performing Feeders	• Applies to the 11kV feeders falling outside low reliability thresholds to be mutually agreed between the Distributors and QCA by 30 June 2001 • Includes Distribution System, Exclusions, and Transmission and Generation interruptions • Includes planned and unplanned interruptions • Does not include momentary interruptions	Annual
Reliability Of Supply Complaints	• Reported on a Total basis, not feeder by feeder • Derived from the Distributor's electronic complaints recording system	Quarterly

QUALITY OF SUPPLY DATA

FIELDS FOR REPORTING

QCA ELECTRICITY DISTRIBUTION: DETERMINATION

Item Number	Data Field	Definition	Reporting period
4.1	Total quality of supply complaints	The total number* of quality of supply complaints received due to all causes, ie the total of 4.2, 4.3 and 4.4	Quarterly
4.2	Network initiated quality of supply complaints	The number* of quality of supply complaints which, after investigation, are found to be caused by network restrictions or events on the network which may or may not be under network control	Annual
4.3	Quality of supply complaints initiated on the customer side of the meter	The number* of quality of supply complaints which, after investigation are found to be caused by faulty customer equipment or customer's operation	Annual
4.4	Quality of supply complaints for which no cause was found	The number* of quality of supply complaints for which, after investigation, no cause was found	Annual

* Expressed as a total number organisation-wide, which can then be normalised in the appropriate way, e.g. complaints per 100,000 network connections

CUSTOMER SERVICE.

The Authority will monitor Ergon Energy's performance in its organisational Guaranteed Service Levels documented below:

GSL - Our Service Promise

When our customers need an electricity connection for their new home, or have no hot water due to a fault in our electricity control system, all they want to know is that we will fix it quickly and on time.

With *Our Service Promise* - they can be assured we'll deliver, because we've put money on it! And while they take advantage of the guarantees below, we'll be continuing to look for even better ways to serve them.

New Connections

Our guarantee: If a customer has lodged the necessary paperwork and supply is available, their electricity will be connected and working by the requested and agreed date.

If we let a customer down, we'll pay them $25 for every day we are late.

Planned Interruptions

Our guarantee: When carrying out upgrades and maintenance that requires us to interrupt supply, we will notify the customer at least four days prior to the outage.

If we let you down, we'll pay: $20 to residential customers, $50 to business customers.

The notice will advise the date and estimated start and finish times planned for the interruption.

Please be aware that power failures can be due to circumstances beyond our control. This guarantee, therefore, does not include interruptions resulting from emergencies, such as storm damage, equipment failure or accidents, or from government imposed power supply restrictions.

Street Lights

Our guarantee: We will carry out streetlight repairs in a customers street by the nominated and agreed date.

If we let a customer down, we'll pay the first customer who reported the problem $10.

Hot Water

Our guarantee: We will attend to hot water enquiries within one day.

If we let a customer down, we'll pay them $20 for every day we are late.

In most circumstances we will be able to determine, in your initial phone call to us, if the hot water problem is under our control and, therefore, part of this service guarantee. If the fault is the customers responsibility, for example the fault is within their hot water system, they will be advised to to take other action themselves.

Trees and Overhead Powerlines

Our guarantee: If a customer contacts us regarding vegetation growth close to powerlines around their premises, we will:

- give the situation our immediate attention if it is posing a risk to public safety, eg sparking.
- if it is not urgent and the tree is not already on our vegetation works schedule, we will visit to make a risk and safety assessment within 20 days of the call and implement appropriate action.

If we let a customer down, we'll pay you $20.

How to Claim

If a customer feels we have let them down, encourage them to call us on 13 10 46. We value their feedback. If they contact us within one month of making their service request and we have not met our promise, we'll credit their next electricity account with *Our Service Promise* payment. If for any reason they request a cheque payment, this can also be arranged.

Any payments made under these guaranteed service levels are ex gratia payments made by Ergon Energy for failure to meet the nominated standards, and are made without any admission of legal liability on the part of Ergon Energy. We reserve the right to amend these service levels to reflect industry changes and customer expectations.