Report - FINAL

Queensland Competition Authority

Draft Determination

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Commercial - in - Confidence

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EXECUTIVE SUMMARY

Introduction

The Queensland Competition Authority (QCA) has issued a Draft Determination[1] regarding allowable levels of efficient operation expenditure (OPEX) with regard to prices (revenue caps) charged by the Queensland electricity distribution network service providers (DNSPs) namely Ergon Energy and ENERGEX Limited (ENERGEX) for each year of the regulatory period to apply from July 2001 for four (4) years.

This determination was based on a series of reports[2][3][4][5][6] from consultants Tasman Asia Pacific (TAP) and Pacific Economics Group (PEG) which concluded that to achieve a worlds best practice equivalent Ergon Energy would need to reduce OPEX by 27.7% and estimate this could most appropriately be achieved over a ten (10) year period. The QCA has rounded up the estimate and applied on efficiency target of 3% per annum for the first four (4) years with assumption that this target would continue throughout the next regulatory period to encompass the ten (10) years at 3% per annum.

Ergon Energy has retained Indec Consulting and Benchmark Economics to assess the TAP and PEG reports and to consider and comment on their accuracy, reasonableness and appropriateness.

The approach undertaken in the assessment was to review the following:

- Analysis of QCA consultant's reports and assessment of the proposed 27.7% (30% QCA) reduction of the OPEX costs.
- The appropriateness of the QCA targets (3% per annum OPEX cost reduction).

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1 Queensland Competition Authority. Draft Determination – Regulation of Electricity Distribution, December 2000.

2 Tasman Asia Pacific – Benchmarking comparison of Ergon Energy and nine (9) Australian Electricity Distributors, report to the QCA, 22 November 2000.

3 Pacific Economics Group – Ergon Energy Operating and Maintenance Cost Performance – Results from International Benchmarking, Report to the QCA, November 2000.

4 Tasman Asia Pacific and Pacific Economics Group – Operations and Maintenance Cost Benchmarks for Queensland Electricity Distribution Businesses – Overview of Findings, Report to the QCA, 23 November 2000.

5 Tasman Asia Pacific and Pacific Economics Group Achieving Identified Savings in Operation and Maintenance Expenditures – Benchmark OPEX costs for Ergon Energy, a paper prepared for QCA, 1 February 2001.

6 Tasman Asia Pacific and Pacific Economics Group – Potential for Improvements in Best Practice in Electricity Distribution, a paper prepared for the QCA, 22 January 2001.

- Growth and reliability factor influences.
- One-off costs in gaining efficiency.

Analysis of the QCA Consultants Reports

This review finds that the efficiency and reliability targets identified in the PEG and TAP reports for Ergon Energy fall significantly outside the range of possibility. Ergon Energy 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.

Testing for Credibility

A good test of the credibility of any statistical analysis is whether its predictions are sensible when translated into the actual dollar value expenditure levels for the underlying variables. Figure 1 compares existing OPEX costs per customer, GWh throughput, and kilometre of line for Ergon Energy and its nominated US peers. Far from having costs levels in excess of its nominated peers we find that Ergon Energy's costs are markedly less. This is not the outcome expected. The reversed nature of Ergon Energy and 'best practice' (its peers) casts a serious doubt over the validity of the analysis.

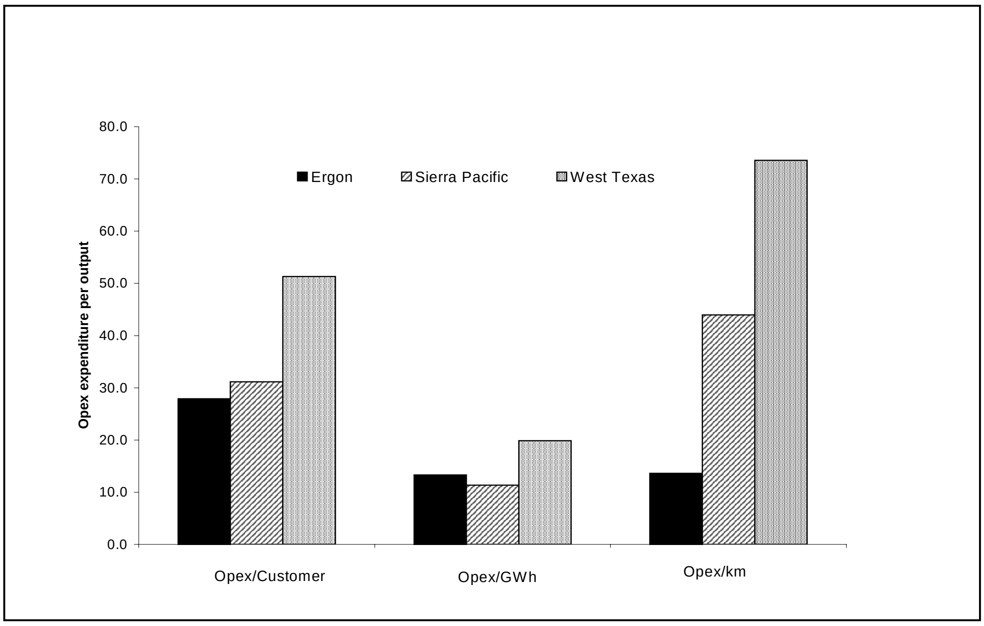

Figure 1: Ergon Energy and US Peers: OPEX Expenditure Levels per unit of Output

Measured against the Australian DNSPs, an efficiency gap of 27.7 per cent means that Ergon Energy's current OPEX costs of $136m (PEG analysis) should be around $100m or the same level as Powercor. This would certainly test the financial viability of Ergon Energy – it would need to maintain and operate a network that is 60,000 kms, or 75 percent, longer than Powercor's for only the same total level of OPEX expenditure.

Pitfalls in Benchmarking 'Building Blocks' Independently

Partial productivity measures can provide misleading estimates of efficiency not only because optimisation of a network involves OPEX/CAPEX trade-offs, but more critically because business conditions and accounting practices have a significant influence on cost allocations.

This Report would argue that consideration of CAPEX is required in estimating the efficiency of OPEX. The building blocks are not independent.

Understanding the Limits to Comparisons

Size - Sheer size presents a challenge in cost comparisons for Ergon Energy. While the networks nominated as US peers exhibit the lowest level of energy density (GWh/km) among the sample of US Investor Owned Utilities (IOU), their density is still three to four times greater than that of Ergon Energy.

Networks, by definition, are spatial. Failure to fully explore the dimensions of distance and density, and their implications for costs and reliability, is the major shortcoming of the PEG and TAP statistical analyses.

US Data - The US data set used for the international study does not include networks experiencing similar business conditions to Ergon Energy. The data in the FERC Form 1 database relates only to US IOUs, which largely supply network services to CBD and urban areas. Their cost structures are fundamentally different (See Figure 1).

Australian Data - Australian data also presents a problem because the small sample that TAP uses for testing contains two quite disparate types of network, urban and rural (see Figure 3). Cost coefficients and cost shares cannot be accurately estimated from average relationships of such a disparate sample. The TAP analysis has not given due regard to these differences.

Reliability

Reliability is a function of distance and investment. More kilometres of line simply means greater opportunity for interference. The US peers nominated for reliability benchmarks have service territories that require 70 per cent less line than Ergon Energy to transport electricity to customers.

Performance Indicators

The comparison of Ergon Energy's performance against performance indicators for the whole sample without adjustment for either scale or business conditions (TAP Report Table A: Summary of benchmarking measures and Section 3) does not provide (the QCA brief required) comparisons among peers in order to gauge the efficiency gap. To label any performance against these unadjusted indicators in terms of 'best' or 'worst' is misleading.

Network Cost Analysis:

Model Specifications

The PEG and TAP reports specify a simple cost function model founded conceptually in the economic theory of economies of scale. Network costs are modelled only as a function of the scale of output. Business conditions are not considered as being appropriately factored into the analysis. Within the electricity industry the business conditions of energy density and customer class are widely recognised as major cost drivers. PEG included customer class but not energy density while TAP has only modelled scale.

Collinearity of Independent Variables

PEG and TAP appear to have based their analysis, and hence their findings, on a data set with collinearity problems, that is, there is a high degree of correlation between the independent predictor variables. Collinearity is a problem in time series or scale measures where a common set of influences move together. It invalidates the tests for significance because the impacts of the predictors cannot be disentangled. The coefficients are not reliable.

Inclusion of Statistically Significant Variables

For reasons that are not explained, PEG has only included some of the parameter estimates in their predictive model though their own test against the critical value suggests that other terms are statistically significant.

Extrapolating Beyond the Range of the Data

In inferential statistics, such as the PEG cost function model, coefficients estimated within a data sample are used to infer or predict performance either of a single business within the sample or of similar businesses not included in the sample. Extrapolating the model to produce estimates beyond the range of the data is not statistically sound.

The US sample of urban based Investor Owned Utilities is not an appropriate data set for assessing the performance of Ergon Energy. Figure 2 throughput (GWh) and line length (km) shows energy density as the diagonal trend line. Ergon Energy lies well outside the parameters of this sample. Extrapolating estimated relationships from this data set to Ergon is not statistically sound.

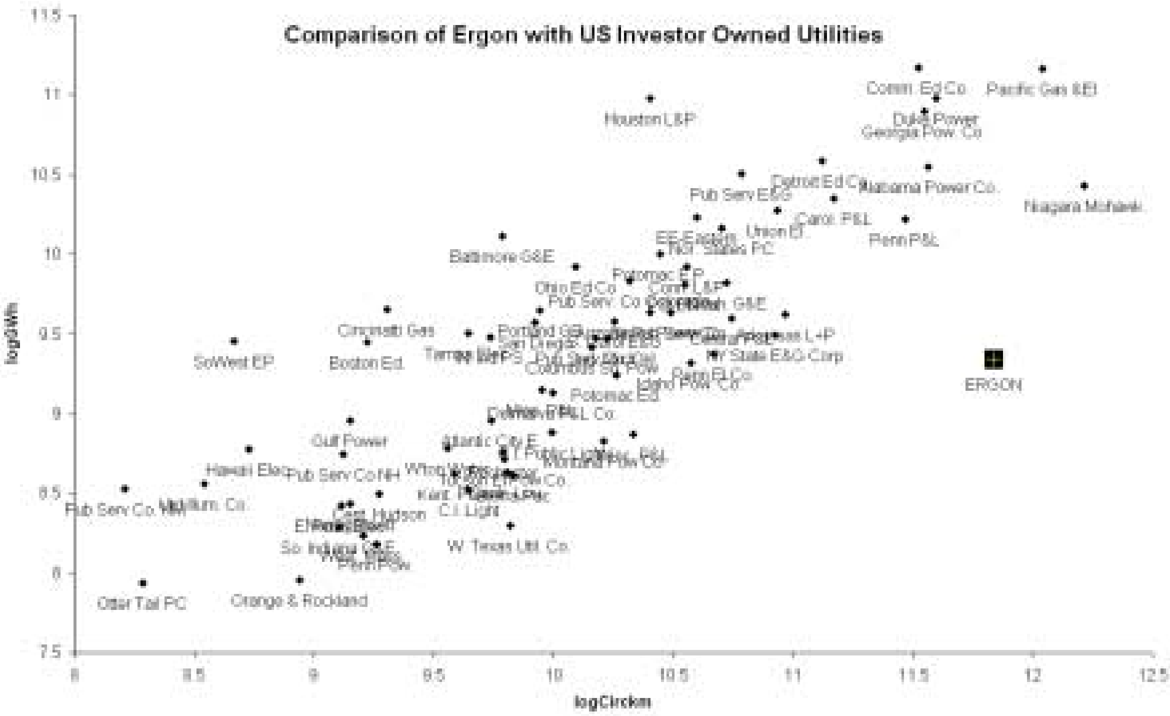

Figure 2: Scatterplot of Network Length versus throughput for US Investor Owned Utilities

The mixed sample of rural and urban networks in the Australian data set means that there can be no common trend in energy density. The scatterplot of OPEX costs and line length in Figure 3 shows two distinct patterns of network density, a high density trend for urban networks and a low density trend for rural networks.

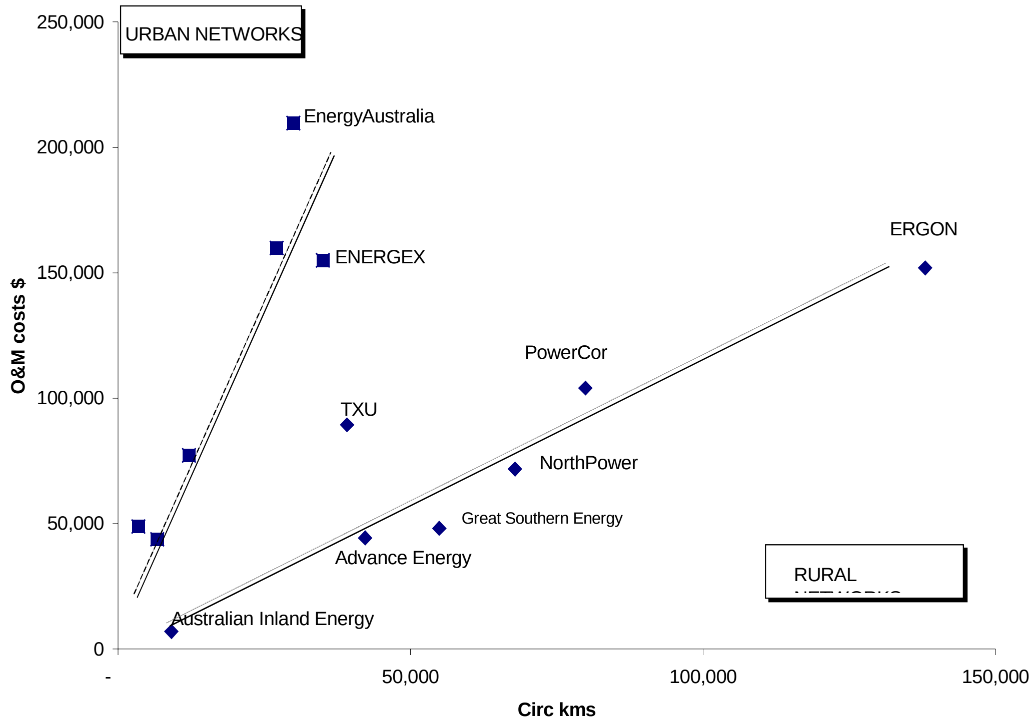

Figure3: OPEX Costs and Distance (Km Wires)

The soundness of estimating a single parameter from what is obviously two independent cost curves must be questioned.

One technique outlined in our report to address the problem of correlated predictors is to use principal components analysis and principal components regression.[7]

A data set based on US IOU data and containing the variable peak demand, which was not considered in the PEG analysis, as well as throughput, customers and network length, has been analysed with principal component analysis. These data were then logged and standardised to accord with the PEG analysis.

[7] Multivariate Analysis.

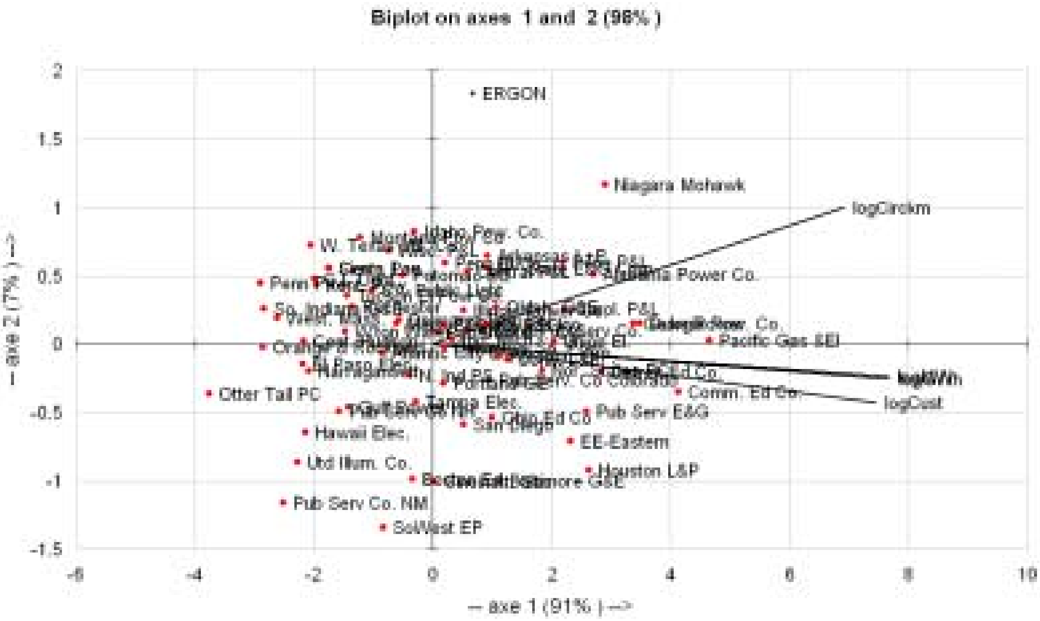

Figure 4: Correlation biplot showing IOU data and Ergon, and the projection of the predictor variables.

The biplot shows even more dramatically how unusual Ergon is compared to the US sample.

__Application to Ergon Energy__

To estimate efficiency and reliability gaps the TAP and PEG reports compare the performance of Ergon with a number of cost and reliability benchmarks. Two benchmarks used are the “Best Australian Performer” by TAP and the “Top Quartile of USA DB’s” by PEG.

The comparisons have little relevance for Ergon Energy. The US largely urban based sample is inappropriate as a comparison for the rural based Ergon Energy.

The TAP report adopts a “cherry picking” approach, comparing Ergon Energy with a fictitious organisation, one that would be ‘best’ in all categories. Without adjustment for variations in business conditions this comparison provides little credible information. The extreme range in OPEX/km from $888 to $9822 among a sample of only 10 DNSPs raises questions as to whether such a diverse partial category comparisons of 'best' or 'worst' and ranking this across such a wide range is misleading.

An Exploratory Analysis Of Australian Distribution Network Costs

Section 3 of our report explores more closely the relationships between network costs, outputs, and business conditions. Using a series of scatterplots (refer Appendix A) to test relationships the analysis reveals strong trends between a number of business conditions and key variables. It is neither exhaustive nor intended to suggest that all the relationships are statistically significant. Nonetheless, the evidence of strong relationships in a number of the key areas does suggest that simple output models do not capture the full impact of business conditions on network costs. Factors affecting Ergon Energy's efficiency not adequately accounted for in the TAP and PEG analysis are:

- *OPEX Unit Costs and Customer Class* - Customer class is a significant cost driver of unit costs. The analysis reveals an inverse trend between high per customer consumption levels (typically associated with larger commercial and industrial customers) and lower unit costs. The link is not linear, DNSPs with higher levels of demand associated with large industrial customers, experience rising costs such as Australian Inland Energy, Advance Energy and Ergon Energy.

- *Units Costs and Density* – Among the Australian sample used for this investigation the DNSPs fall neatly into two discrete classes, rural and urban (refer Figure 3). OPEX/GWh for the urban DNSPs is around 50 per cent of that for the rurals. The average number of customers per km of line for the urban networks is around thirty five (35) but only around four (4) for the rural networks such as Ergon Energy. Viewed in terms of resources required, this means that a rural DNSP must service and maintain up to 250 metres of line for each customer connected in contrast to an urban network which needs to service only 25 metres.

- *Reliability* - Reliability is an output. A high level of reliability requires significant CAPEX investment. Higher reliability tends to be associated with the higher density areas where the level of throughput can justify the assets investment. Analysis of SAIDI reveals an association between rising levels of reliability and shorter line lengths. Ergon Energy could not be expected to achieve the level of reliability of a DNSP that exhibited urban/rural characteristics.

Asset Management

The Ergon Energy network faces a different operating environment, community risks and customer focus to the DNSPs with which it is being compared.

The network is an amalgamation of six (6) smaller businesses covering geographically and demographically diverse areas with some of the smallest populations per square kilometre that would be found in the world. The previous organisations could not individually afford a strong network planning and standards group and different work practices and standards developed across the businesses.

Ergon Energy needs to undertake additional OPEX costs in order to correct this situation and has identified major projects and prepared a business plan in relation to asset management to develop the skills, information and systems to facilitate long-term network optimisation and rationalisation (refer Appendix B - Asset Management for full detail regarding the asset management strategy).

The QCA therefore needs to take into consideration firstly, the asset base and the condition of that base and secondly, the OPEX investment required to achieve best practice. Comparisons of Ergon Energy to other DNSPs without such consideration can lead to revenue cap reductions, which actually limit the quantums and rate of savings achievable by the network.

Applicability of Targets

Fit for Purpose

The approach taken by TAP and PEG as outlined in Section 2 of our report does not accurately assess the overall efficiency or performance of Ergon Energy as a distribution business. It is not fit for the purpose for which it is intended.

Furthermore, the aggregate view does not allow detailed assessment as to:

- Factors which are outside management control.
- The ability and timeframe of Ergon Energy to meet the proposed targets.

Efficiency Issues

The TAP and PEG reports present no evidence in support of their assertion that the electricity industry will continue to reduce unit cost rates by a constant even percentage per annum. The lack of supporting evidence as to rates of improvement raises significant doubts as the accuracy of the prediction.

Regarding rates of improvement to best practice, data relating to efficiency improvement rates has been collated in our report to show that step improvement rates are not straight-line. Continuous improvement programs generally deliver straight-line cost improvements of the magnitude of 2% per annum or less. Further improvements require step changes.

There is a need for greater identification in the Determination of the potential for achieving savings (other than the TFP approach involving benchmark comparisons against DNSPs who have already undertaken significant reform). Assessments must consider both cost efficiency and service level performance and must acknowledge a number of inter-dependencies. Whilst the TAP and PEG report does acknowledge some inter-dependencies, and attempts to adjust for these several significant gaps exist:

- The TAP and PEG methodology does not take into consideration customer class, energy density and business conditions.
- TAP and PEG's data and analysis does not take into consideration the age or prevailing condition of Ergon Energy's asset base and the size of the network relative to the comparators used.
- Recognition of Government obligations and customer service standards beyond SAIDI that impact upon operating costs.
- The relationship between CAPEX and OPEX costs.

Improvements in Best Practice

The sources of improvements in best practice as detailed in the TAP and PEG improvements papers[8] are all incorporated in the step change improvements as outlined in the analysis of the ability of Ergon Energy to achieve the proposed OPEX targets in the report. The restructuring and asset management changes proposed by Ergon Energy incorporate these step changes required to move beyond current best practice.

Consequently, our analysis and experience indicates that the TAP and PEG conclusion of a 27.7% reduction in OPEX applied evenly over a ten (10) year period is incorrect in both quantum and timing.

Growth and Reliability

TAP state in their report that the gap to best Australian practice aside from reducing OPEX costs can also be achieved by OPEX costs remaining the same and output increasing by 17.5% or reliability increasing. The QCA should consider further the TAP analysis that given all else being equal, and OPEX remained the same, then growth and reliability improvements alone could achieve the proposed efficiency targets within four (4) to six (6) years.

In addition, the QCA is estimating that only 50% of the growth is directly related to OPEX expenditure (without detailing justification for this decision). In normal circumstances, for a fully optimised network without maintenance debt, this type of estimate may be reasonable. However, as outlined in our report, Ergon Energy is not that type of a network and the QCA estimate as to growth impacts on OPEX could be too low as the state of the network is not factored.

The QCA growth factor assumes scale economies, as modelled by TAP and PEG in that costs are modelled as a function of output but to achieve these, this will require one-off OPEX investments in asset management processes in Ergon Energy's case.

Additionally, QCA are not linking other issues with pricing (revenue caps) such as one-off restructuring costs, the restructuring required and the issue of holding current OPEX levels whilst restructuring occurs, with growth and improved reliability contributing to increasing input efficiency during the initial restructure period.

One-Off Restructuring Costs and Timing

[8] Reference - Efficiency and Benchmarking of NSW Electricity Distributors - Discussion Paper, DP33, Page 7, February 1999.

Ergon Energy has identified that it needs to implement best practice from a fragmented network and has submitted restructure proposals including reliability improvement.

Experience indicates that any restructure process needs to be completed in the shortest possible timeframe. Accordingly, if the QCA do not include the restructuring costs as part of the revenue cap, then the costs of restructure would become "sunk costs" as revenue (price) reductions would be immediate and not occur after potential savings are realised. Ergon Energy are of the view that the customer should receive the full benefit of cost savings as they occur in line with the incentive regime.

The QCA Draft Determination with regard to one-off restructuring costs as proposed by Ergon Energy has stated that: "As with Ergon Energy's restructuring costs, improving service quality and investment in efficiency improvement should provide benefits into the future which more than compensate for the short term financial costs".

The implication of the QCA comment is that the savings will be self-funding.

In other jurisdictions the approach has been that the DNSPs restructured under the previous price structures and that the resultant savings were passed on in the next round of price reviews by benchmarking to best practice and not passed to the customer as they occur.

If the restructuring is to be self-funded, the restructure would be on a piecemeal basis in that a financable portion of the restructure from cash flow would commence the first round of initiatives, then further restructure investment would not occur until the first round of savings was realised. Then further investment could occur on a rolling savings realisation basis.

This is not the optimal way to perform restructuring. The potential savings would be applied to restructuring costs over a longer time frame (with the possibility of the process becoming stalled). That would mean to be self-funding, price (revenue cap) decreases, in relation to OPEX would need to be delayed by a period which is longer than the four (4) year regulatory price period.

If revenue caps are decreased to the targets proposed from the start of year one (1), then Ergon Energy would either have to have a working capital injection or a loan from their owner, namely the government.

A working capital injection would increase the asset base attracting WACC at 8.92% and the working capital returned as the savings occur. This would also require the current level of OPEX to be maintained as the revenue cap until the savings period is finished.

Alternatively, as other jurisdictions (involving DNSPs against which Ergon Energy is benchmarked) have had an incentive based regime to progress these savings prior to price re-sets, a loan approach would be an alternative method to trigger the restructure. In this case, Ergon Energy's proposed restructure timetable would take over three (3) to four (4) years to complete and savings would not be realised until year six (6), when another price re-set would occur at year five (5) without the savings being achieved.

In summary, the requirement is to achieve the restructuring within four (4) years so that Ergon Energy has attained the savings before the next price re-set otherwise the issue of "sunk costs" remains into the next regulatory period.

The options are as follows:

- The options be self-funded in which case payback would be longer than seven (7) years still requiring the revenue cap to remain at current OPEX level for the whole period and the restructure would run the risk of stalling.
- A working capital injection which would possibly have a longer payback period than four (4) years which would require the current OPEX costs levels to remain as the revenue cap.
- A loan option which would require current OPEX costs to remain as the revenue cap for four (4) years.
- Include the restructure costs in the regulated revenue cap for the four (4) year regulatory period with target savings rates commencing after year two (2).

Clearly, the last option would be more preferable in achieving all stakeholder interests.

The above comments need to be considered in relation to:

- That the 30% savings target as applied at an even rate of 3% per annum is considered inappropriate.
- Growth and reliability factors will also improve efficiency over the four (4) years.

Conclusions

The conclusions that TAP and PEG draw with respect to cost savings targets, and rates of improvement, in our view, cannot be practically achieved because:

- The TAP and PEG analysis is not satisfactorily correlated to the Ergon Energy network leading to inappropriate conclusions.
- The TAP and PEG conclusion of a 27.7% reduction in OPEX applied evenly over a ten (10) year period is incorrect in both quantum and timing.
- CAPEX is a key driver of OPEX and investment in CAPEX needs to be undertaken prior to impact on OPEX cost.
- In order to meet long term improvements of a 2-3% magnitude, Ergon Energy needs to undertake a major reform initiative as detailed in the report.
- The reform must occur in the first 1-3 years otherwise impetus will fail.
- 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.
- This reform will take a longer time if the savings are to be self-funded.
- If savings are to be achieved in the regulatory period the one-off restructuring costs need to be included in the Determination.
- The QCA has concentrated soley on reducing OPEX (by the quantum the consultants recommend) but has not considered the aspect of growth and improved reliability improving efficiency whilst the restructuring is undertaken.
- The TAP and PEG studies do not meet the QCA key objectives of:
  - Maintaining the financial integrity of the business;
  - Reducing costs without compromising customer services requirements.

If the QCA base savings at 3% per annum and the restructuring costs are not included in the regulatory revenue then the key objectives of the QCA will not be met.

- The savings percentage and rate need to be reviewed.

1. REPORT INTRODUCTION

The Queensland Competition Authority (QCA) in December 2000, became the jurisdictional regulator for prices (revenue caps) charged by the Queensland electricity distribution network service providers (DNSPs) namely Ergon Energy and ENERGEX Limited (ENERGEX). The QCA has issued a Draft Determination[9] regarding allowable levels of efficient operating expenditure (OPEX) in the broader sense incorporating both operations and maintenance costs for both DNSPs for each year of the regulatory period to apply from July 2001 for four (4) years.

In determining the OPEX efficiency levels of expenditure, the QCA retained consultants Tasman Asia Pacific (TAP) and Pacific Economics Group (PEG) who each issued an individual report[10][11] and a joint report[12] prior to the Draft Determination. The reports stated for Ergon to achieve a best practice equivalent with the top Quartile (Lower End) of USA DNSPs Ergon Energy would need to reduce OPEX by 27.7% and estimate this could most appropriately be achieved over a ten (10) year period. The QCA has rounded up the estimate and applied on efficiency target of 3% per annum for the first four (4) years with assumption that this target would continue throughout the next regulatory period to encompass the ten (10) years at 3% per annum.

Subsequent to the Draft Determination TAP and PEG have issued two further reports namely Achieving Identified Savings[13] and Potential for Improvements in Best Practice in Electricity Distribution[14].

Ergon Energy has retained Indec Consulting and Benchmark Economics to assess the TAP and PEG reports and to consider and comment on the their accuracy, reasonableness and appropriateness.

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9 Queensland Competition Authority. Draft Determination – Regulation of Electricity Distribution, December 2000.

10 Tasman Asia Pacific – Benchmarking comparison of Ergon Energy and nine (9) Australian Electricity Distributors, report to the QCA, 22 November 2000.

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13 Tasman Asia Pacific and Pacific Economics Group Achieving Identified Savings in Operation and Maintenance Expenditures – Benchmark OPEX costs for Ergon Energy, a paper prepared for QCA, 1 February 2001.

14 Tasman Asia Pacific and Pacific Economics Group – Potential for Improvements in Best Practice in Electricity Distribution, a paper prepared for the QCA, 22 January 2001.

In assessing the QCA Draft Determination, we draw upon the information in the quoted reports, data provided by Ergon Energy , other publicly available reports and studies, and to utilise our considerable joint experience and expertise in both benchmarking and the assessment and improvement of organisational and operational efficiency.

The approach undertaken in the assessment was to review the following:

- Analysis of the TAP and PEG Reports and assessment of the proposed 27.7% (30% QCA) reduction of the OPEX costs.
- The appropriateness of the targets (3% per annum OPEX cost reduction).
- Growth and reliability factor influences.
- One-off costs in gaining efficiency.

The methodology employed was to review:

- The TAP and PEG reports with regard to practical statistical and mathematical soundness.
- The appropriateness of the TAP and PEG reports in satisfying the QCA requirements.
- The cost drivers of the Ergon network and the relationship of those to the Draft Determination (per TAP and PEG).
- Ergon Energy’s asset management strategies, planning and implementation.
- The relationship of OPEX to capital expenditure (CAPEX).
- Impediments to achieving the OPEX efficiency targets.
- The ability of Ergon to achieve the targets on a year by year basis.
- Implications of the one-off costs proposed by Ergon to be included in the regulatory pricing.

2. ANALYSIS OF THE QCA CONSULTANTS REPORTS

This Section reviews the studies commissioned by the QCA to assess the comparative OPEX cost performance of Ergon Energy as prepared by PEG and TAP. It considers the methodologies used; the modelling techniques, and the conclusions reached.

Firstly, this review places the PEG and TAP Reports in the context of the regulatory framework being developed by the QCA for the DNSPs, in particular, it considers the appropriateness for regulatory price setting of the efficiency 'gaps' identified. The cost performance and benchmarking methodologies are considered. The validity of the model specification for measuring the comparative efficiency of DSNP's is then addressed. Comments on the analysis and the conclusions are presented in the final section.

2.1. Role of Benchmarking in the Regulatory Framework

The QCA Draft Determination,[15] proposed an "incentive-based" regulatory regime based on the CPI-X adjustment mechanism for determining network prices. This form of price setting allows regulated revenues to adjust to changes in the general price level while reducing by an efficiency factor "X". In adopting this approach to providing efficiency drivers for DNSPs the QCA stated key objectives for setting the X factor as:

- maintaining the financial integrity of the businesses; and
- reducing costs without comprising customer service quality requirements.

QCA retained PEG and TAP to assess Ergon Energy's OPEX cost performance relative to Australian and US DNSPs in order to assist in identifying the potential efficiency gains to be incorporated into the X factor. **Performance was to be adjusted for the operating environment to enable comparisons against suitable peers and to facilitate identification of areas where inefficiencies could be reduced.**

As the estimated efficiency gains contribute to the determination of the X factor, and hence provide the incentive to improved operating performance, it is a necessary condition that they be operational and under managerial control. Using

[15] Queensland Competition Authority, Draft Determination – Regulation of Electricity Distribution, December 2000.

the benchmarks estimated by PEG and TAP to set efficiency targets implies not only that Ergon Energy will be able to achieve these, but also that it will be able to do so without detracting from the financial integrity of the business or compromising customer service quality.

This review will show that any X factor based on the OPEX efficiency gaps reported for Ergon Energy in the studies will not meet these objectives. Contrary to claims in the reports that they "capture the relationship between the cost of service and business conditions in the service territory", this review finds that business conditions such as density have not been taken to account. Inadequate specification of the analytical models, inappropriate data sets, and a failure to distinguish between output scale and business conditions have generated estimates of efficiency gains that are fallacious. The efficiency targets fall significantly outside the range of possibilities for Ergon Energy.

2.2. Testing for Credibility

A good test of the credibility of any statistical analysis is whether its predictions are sensible when translated into the actual expenditure levels of the underlying variables. That is, what do the statistical predictions in percentage terms mean in terms of the dollar value of OPEX per unit of output, eg OPEX/GWh?

The efficiency gap identified in the reports implies that Ergon Energy's *existing* level of OPEX expenditure per unit of output is 27 per cent *above* that of its more efficient peers. However, when the actual dollar value of OPEX expenditures per unit of output for Ergon Energy is compared against its nominated US peers, Sierra Pacific and West Texas Utilities we find that this is not so.

Figure 2.2-1 compares existing OPEX costs per customer, GWh throughput, and kilometre of line for Ergon Energy and its US peers. The results are startling. Far from having costs levels in excess of its nominated peers we find that Ergon Energy's costs are markedly less. 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!

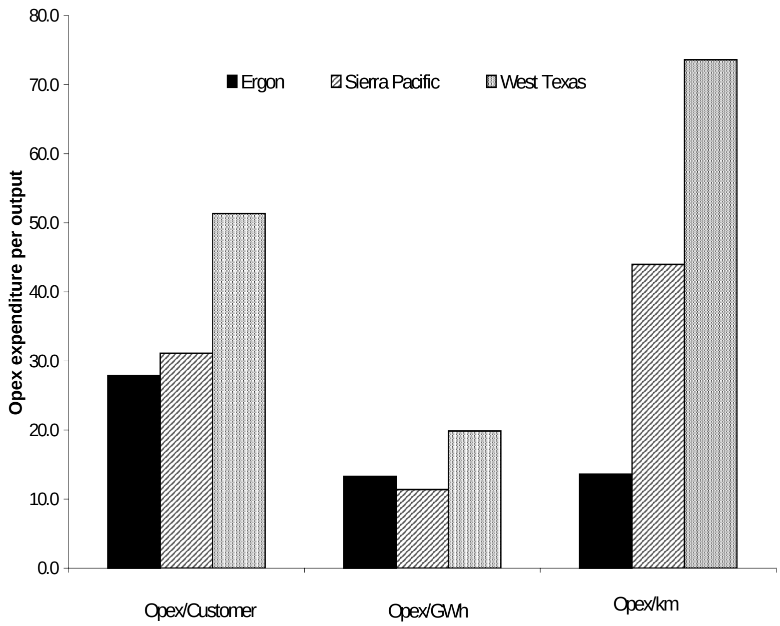


Figure 2.2-1: Ergon Energy and US peers: OPEX expenditure levels per unit of output

This is not the outcome expected. As Figure 1 in the joint report by PEG and TAP "Potential for Improvement in Best Practice in Electricity Distribution"[16] depicts, the cost performance of Ergon Energy should lie above, not below, 'best practice' Figure 2.2-2 incorporates the above costs into an adaptation of Figure 1 in the joint report. The reversed nature of Ergon Energy and 'best practice' casts a serious doubt over the validity of this analysis.

[16] Pacific Economics Group and Tasman Asia Pacific, 2001, "Potential for Improvement in Best Practice in Electricity Distribution".

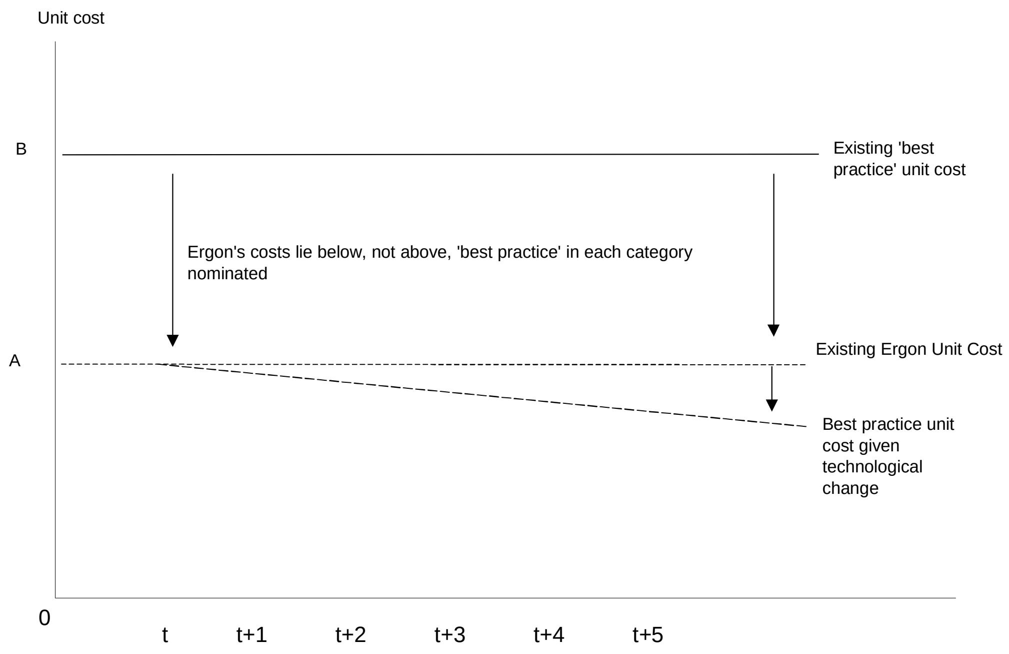


Figure: 2.2-2: Time profile of unit costs for Ergon Energy moving towards best practice – adapted from Figure 1-Joint Report PEG and TAP

The factors that give rise to this unexpected outcome, including the unsuitability of the US FERC Form 1 database for cost comparisons with rural Australian networks, are discussed in the following sections.

The outcomes are no less questionable when the Australian comparisons are examined. Figure 2.2-3 presents the relationship between OPEX costs and length of line for a number of Australian DNSPs. The existing position of Ergon Energy is noted together with its approximate position if those costs were reduced by 30 per cent, the efficiency gap estimated. That is, if the gap is 30 per cent what does it mean in terms of current expenditures?

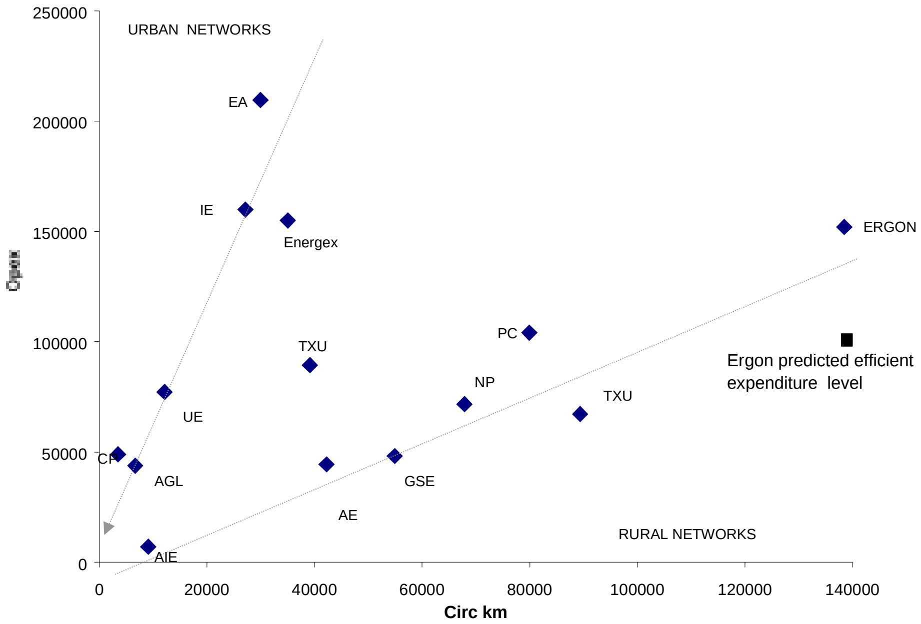


Figure 2.2-3: OPEX Cost and Line Length

The *predicted* cost/km relationship suggests that to meet its efficiency target Ergon Energy would need to reduce its OPEX costs to the same level as Powercor, around \$100m per year. This would be a challenge. It would certainly test the financial viability of Ergon Energy to maintain and operate a network that is 60,000 kms, or 75 percent, longer than Powercor's for only the same total level of OPEX expenditure.

2.3. Pitfalls in Separate Estimation of Cost Performance

This Report would argue also that estimating the efficiency of OPEX, CAPEX needs to be considered as driver of OPEX.

Lacking adequate reliable and comparable historical information on network productivity, the QCA did not fully adopt econometric modelling methods for estimating the 'total' efficiency factor X (TAP total productivity factors). As an alternative, the QCA has based its targeted efficiency improvements on individual assessment of particular cost categories, using "partial productivity measures to estimate the X factor indirectly"[17]. This strategy effectively does not consider CAPEX in relation to OPEX with regard to optimisation of the network.

Whilst partial productivity factors were used, this approach effectively treats OPEX expenditure as independent of CAPEX. This Review would recommend caution in adopting the conclusions. Partial productivity measures can provide misleading estimates of efficiency by not picking up expenditure trade-offs, say between OPEX and CAPEX, but more critically because business conditions and accounting practices have a significant influence on cost allocations. Business conditions such as customer density and customer class have been found to influence the proportion of OPEX costs relative to CAPEX.

Two examples illustrate this finding. Firstly, with regard to business conditions, the analysis of the cost performance of a number of Australian DNSPs suggests a link between the ratio of OPEX costs to total costs and customer density. Measured as customers per km of line length, density is widely accepted as a non-controllable business condition. The negative sign on this relationship suggests that OPEX costs are likely to rise as a proportion of total costs as customer density declines.

With one of the lowest customer densities in the Australian sample, Ergon Energy could be expected to exhibit a ratio of OPEX costs to total costs that is above the average. Certainly, this ratio should be above that of the higher density ENERGEX. This is confirmed by the data in Figure 2.3-1 which presents a scatterplot of the ratio of OPEX costs to total costs and customer density, measured as customers per km of line. The declining relationship between this ratio and rising energy density emerges clearly. Moreover, the rate of decline varies depending the type of network service, rural or urban.

[17] Queensland Competition Authority, 2000 Ibid, pp30.

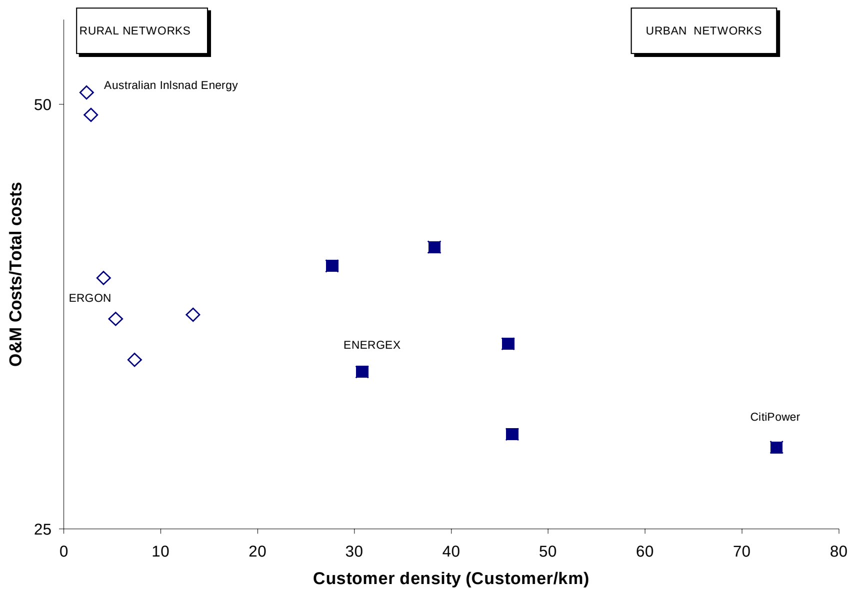


Figure 2.3-1: Ratio of OPEX Costs to Total Costs and Customer Density

The second example relates to differing accounting practices between the states. Queensland networks traditionally were required by industry regulation to expense pole replacements in contrast to Victoria where regulations required that they be capitalised. Historical cost comparisons without due regard for these different practices would be invalid.

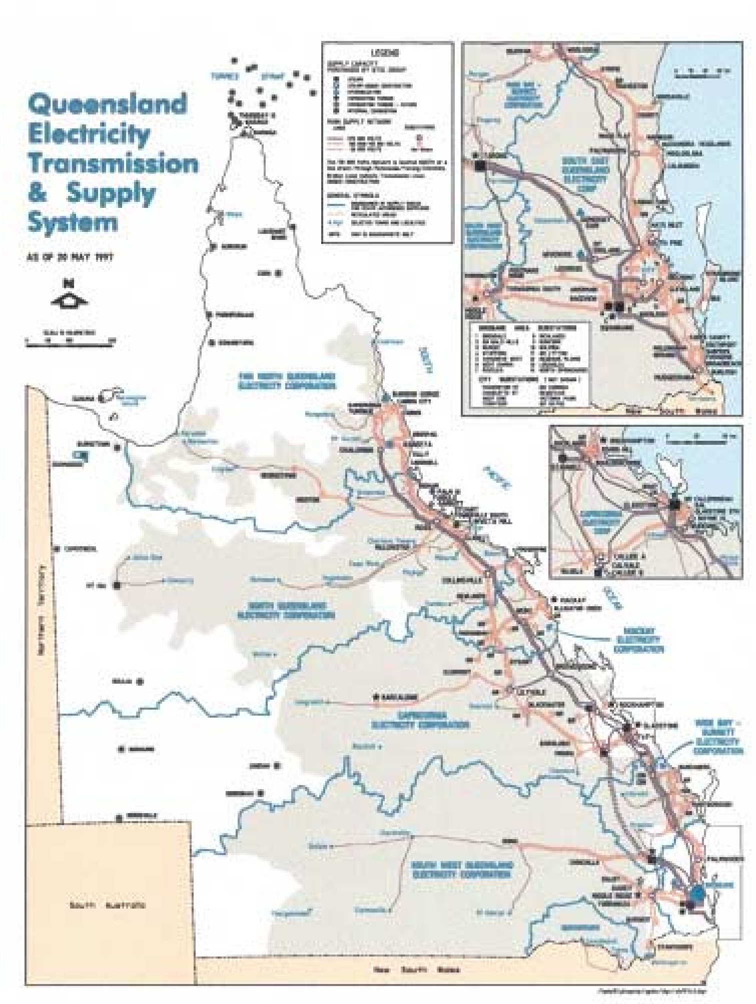
Such interdependence between cost components and business conditions signals the importance of estimating total cost efficiency, not partial productivity as proposed by the QCA. Comparing OPEX performance independently in an analysis where customer density has not been included in the model specification, as is the case in both the PEG and TAP Reports, can only disadvantage those DNSPs with lower customer densities. That is, **a higher measured OPEX cost performance on the part of Ergon Energy could reflect the business conditions it faces rather than its operating efficiency.**

2.4. Understanding the Limits to Comparisons

2.4.1. Size

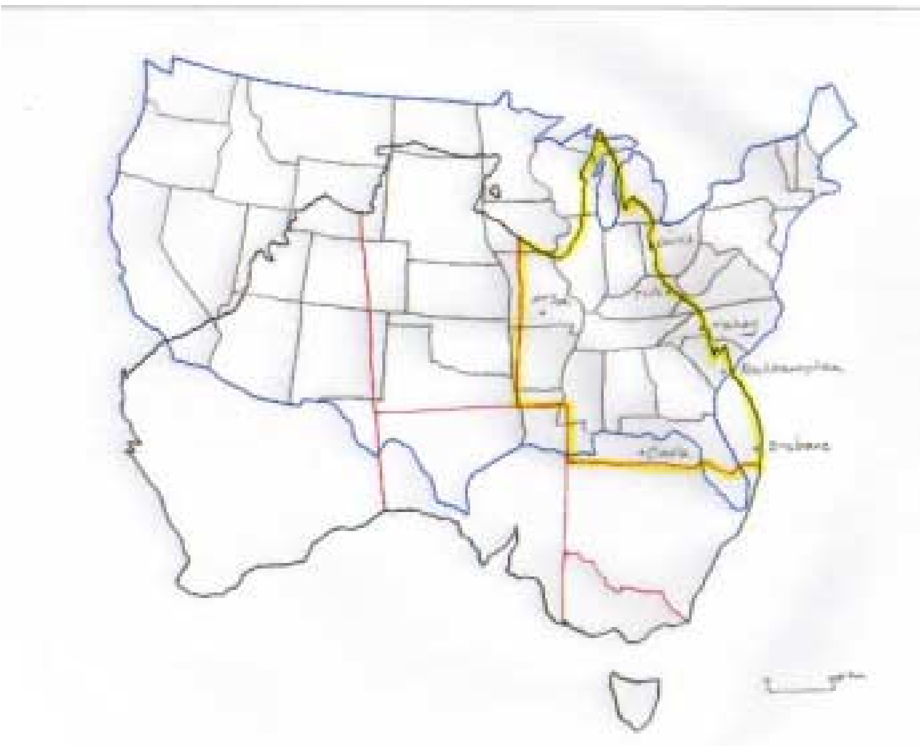
Sheer size presents a challenge in cost comparisons for Ergon Energy. It is unique among the US and Australian networks with a service territory many multiples greater than any DNSP in either the Australian or the US sample. While the spatial dimension of Queensland is generally recognised in cost comparisons of this type, its size - and its implications for costs - is often underestimated. This is certainly so in the two studies under review.

The following three maps have been created to illustrate the disparity between Ergon Energy and other DNSPs, particularly those in Australia and the US.



Map 1 – The Ergon Energy Distribution Area

Map 2 - Australia and Europe



Map 3 - Australia and the United States

The implications for performance comparison are great. In nominating peers for benchmarking Ergon Energy's reliability, PEG compared both Ergon Energy's and Energex's peers and selected three US networks in Texas, Idaho and the Pacific West Coast in nominating the Ergon Energy OPEX target. While these three networks exhibit the lowest level of energy density (GWh/km) among the sample of US Investor Owned Utilities (IOU) used in the international analysis, their density is still three to four times greater than that of Ergon Energy. In simple terms this means that for each MWh delivered to its customers Ergon Energy has to maintain reliability over a distance four times greater than its recommended peers. It seems unlikely that Ergon Energy could achieve the reliability benchmark without substantial investment to offset this greater distance.

The critical difference between Ergon Energy and other DNSPs is that its length of line is spread over a vast territory. There are a number of US networks that exhibit similar lengths of line but these wires are closely reticulated to service areas that would fit within just a portion of the service territory of Ergon Energy. Common sense suggests that servicing a network that distributes electricity over this greater land mass would involve additional cost. It requires more of all resources just to provide a modern day level of service: maintenance depots, operations and maintenance staff, inventory, travelling cost.

To gauge the relevance of the efficiency target to a network of the scale and type of Ergon Energy, a number of comparisons are set out in Table 2.4.1-1. The estimated 27.7 per cent efficiency gap measures the gap between *existing* levels of expenditure. Substituting the estimated efficient OPEX expenditure (that is, current expenditure less the targeted 27.7 per cent) into a number of cost ratios provides a reality check for the predictions of the statistical models.

	OPEX/km line	OPEX/GWh	OPEX/Customer
Energy Australia	670	8.7	15.12
Integral Energy	589	10.6	21.29
NorthPower	106	17.4	19.79
Great Southern Energy	87	16.1	21.31
Advance Energy	105	16.0	37.73
Australian Inland Energy	77	16.5	32.85
AGL	655	10.7	17.14
CitiPower	1408	9.9	19.15
Powercor	130	20.2	17.82
TXU	229	13.8	17.13
United Energy	638	11.2	13.92
Energex	442	9.5	14.39
Sierra Pacific	444.38	11.35	31.13
West Texas Utilities	736.93	19.84	51.34
Ergon Energy (Actual)	**110**	**13.3**	**28.04**
Ergon Energy (Prediction)	*74*	*8.9*	*18.75*

Table 2.4.1-1: OPEX Cost Ratios

Considering firstly the measure of OPEX per length of distribution line, to achieve its estimated efficiency level Ergon Energy would be required to lower its OPEX/km below any DNSP in Australia. Lower even than tiny Australian Inland Energy. In terms of the spatial relationships depicted in Maps 2 and 3, this is equivalent to operating a network over the distance from Finland to the Black Sea or from New York to Miami– for the same average line cost as servicing Broken Hill.

However, when OPEX costs per GWh are compared, the equivalent targets for Ergon Energy are the large CBD type networks, CitiPower, Energex, EnergyAustralia and Integral Energy. Yet Table 2.4.1-1 shows clearly that rural DNSPs, on average, have a ratio of OPEX to GWh throughput that is approximately double that of the urban centres. Measured against customer numbers, OPEX costs may appear to move closer to the other rural DNSPs but this is misleading. The industrial nature of some of Ergon Energy's customer base relative to other rural networks, means that the most comparable DNSPs for this indicator would be Australian Inland Energy and Advance Energy, which service a number of large gold and other mining areas.

Networks, by definition, are spatial. Failure to fully explore the dimensions of distance and density, and their implications for costs and reliability, is the major shortcoming of the PEG and TAP statistical analyses. Size does not preclude cost comparisons. It does, however, place greater emphasis on ensuring that a truly comparable data set is utilised and that the model specified takes fully into account the density cost drivers - energy and customers.

2.4.2. US Data

Acquiring a robust and *appropriate* data set is widely acknowledged as a significant hurdle in undertaking credible comparisons of cost performance, especially at the international level.

The US data set used for the international study does not include networks experiencing similar business conditions to Ergon Energy. The data in the FERC Form1 database relates only to US IOUs, which largely supply network services to CBD and urban areas. This structure is confirmed by the disparate energy densities between Ergon Energy and its benchmark peers, discussed earlier. Low density rural networks that would more closely equate to the conditions experienced by Ergon Energy tend to be operated by the public sector, either rural or cooperatives, and will not appear in the FERC Form 1 database. The implications of using an urban based data set to assess the cost performance of rural networks, particularly Ergon Energy with its extreme dimensions are elaborated in Section 2.6.

Australian Data - Australian data also presents a problem because the small sample available for testing contains two quite disparate types of network, urban and rural. The difference between the two networks is statistically significant. For example, the difference between urban and rural networks for OPEX costs/line length is statistically significant at the 99 per cent level (Figure 2.2-3). It is difficult to accept that urban and rural cost coefficients and cost shares can be accurately estimated from statistical assessment of average relationships for the whole group.

The TAP analysis has not given due regard to these differences. Adjusting for variations in scale may take into account the differing impacts of greater or less numbers of customers, GWh, or distance, but it does not account for any impacts of the *interaction* between the outputs. As influential business conditions the interaction terms, particularly GWh/km (density) and GWh/customer (customer class), should be considered an essential part of cost and reliability analysis.

2.4.3. Reliability

Identification of credible reliability benchmarks has also been handicapped by the lack of a suitable database. The US peers nominated for reliability benchmarks have service territories that require no greater than 15 to 25 per cent of the lines required by Ergon Energy to transport electricity to customers. In Australia, the only network to even closely resemble Ergon Energy in terms of scale is Powercor, and it has only half the line length.

Reliability is a function of distance and investment. More kilometres of line simply means greater opportunity for lightning strikes, tree interference, or even poles knocked over by traffic.

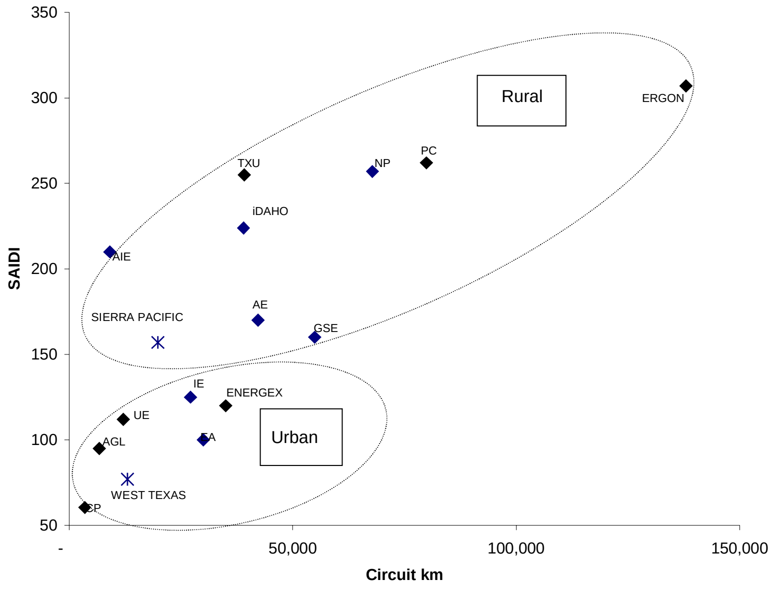


Figure 2.4.3-1: OPEX Costs and Reliability – Australia and the US

In its annual reporting on distribution network performance, the NSW Ministry of Energy and Utilities[18] observed that:

"Distributors with most customers in highly urbanised areas generally have better reliability outcomes than those with large customer numbers in rural and small urban areas. Rural electricity feeder lines are usually long, more susceptible to environmental factors, take longer to fault-find and repair, and usually can only be supplied from one source. **It is therefore not reasonable to directly compare the performance of mostly rural distributors with mostly urban distributors."**

Strategies to reduce outages require resources, and hence raise costs. For meaningful comparisons reliability comparisons should incorporate density factors and resources utilised into the analysis. This is not the case in either the PEG or TAP reports.

[18] Ministry of Energy and Utilities NSW Government, "1998-1999 NSW Electricity Network Management Report".

2.4.4. Performance Indicators

The comparison of Ergon Energy's performance indicators against the data for the whole sample without adjustment for either scale or business conditions (TAP Report Table A: Summary of benchmarking measures and Section 3) is somewhat surprising. The QCA brief required comparisons among peers through adjustment for business conditions in order to gauge the efficiency gap. Without adjustments, any difference between Ergon Energy and the other DNSPs could be due to any number of factors:

- *Financial indicators*: outcome is driven by past government policies;
- *Price:* Normalising cost performance against kWh throughput as a measure of efficiency is not recommended. Simply, the larger the denominator (kWh) the lower the price. Unadjusted, it does not measure performance only relative consumption levels.
- *Reliability:* The difference between urban and rural reliability is statistically significant (refer figure 2.4.2-1). Comparisons should not be made across the entire sample.
- *Labour productivity*: the Productivity Commission is withdrawing from use of this measure as the changes to corporate operating procedures eg outsourcing have diminished its usefulness.
- *Transformer utilisation*: though many factors determine the utilisation of transformers, the class of customer is one of the most significant. High load factors associated with industrial demand give rise to high capacity utilisation and high transformer utilisation. Ergon, with one of the highest load factors in the group, does well in distribution transformer utilisation. Conversely, utilisation at the sub-transmission level is low reflecting the transformation requirements of a long network and the difficulty of optimising assets where loads are less dense.
- *OPEX Costs:* There is no adjustment for the variation between urban and rural networks for the measure of costs against km of line. As discussed above, measures against GWh are unreliable. Powercor may have the 'worst' measure of the rural DNSPs for this indicator but only because it has the lowest level of consumption per customer

at around 8,800 kWh. Ergon Energy has the 'best' measure of the rurals but it has a large industrial base and a consumption per customer of around 21,000 kWh.

The unit OPEX measure does not represent an adjustment for business conditions. The adjustment has been made on the basis of output scale (eg number of customers, GWh throughput) not business conditions (see Section 2.5 for a discussion on the difference between output and business conditions). The differences between the urban and rural DNSPs was not factored in nor is there any accounting for business conditions such as density and customer class.

Suitable data is the foundation of any robust performance assessment. Coefficients determined on the basis of an urban sample instead of rural, or on an average of extremes can only give rise to misleading estimates and predictions. To label any performance against these unadjusted indicators in terms of 'best' or 'worst' invites the question against what?

2.5. Network Cost Analysis

2.5.1. Evolution

Though there is a long history of scholarly research into the productive efficiency of the electricity supply industry, a robust model that identifies key cost drivers for distribution networks and quantifies their impacts is still to emerge. Early analysis, based on the vertically integrated industry in the UK and the US where most research has been undertaken, tended to specify simple input/output models with industry output most often defined as energy supplied to end-use customers. As an output measure for vertically integrated businesses, where other functions performed by the utility were internalised in the production process, this may have been acceptable but it is entirely inappropriate for spatially determined distribution networks.

Unbundling vertically integrated utilities into separate businesses spurred interest in assessing the productive efficiency of distribution networks. Adding emphasis to this interest has been the requirement of the recently created economic regulators for efficiency benchmarks for price setting purposes. A growing array of analyses of the nature and scope of input costs, industry outputs, cost drivers, and business conditions is contributing to an improved understanding of networks as a stand-alone business.

There remains, however, a certain lack of clarity in the use and meaning of some of these terms. This can have the effect, for example, of confusing network outputs with business conditions. In the view of this Report:

- An output is a product or service delivered by the network and resourced by its inputs, for example energy capacity, customer connections, or line length.

- A business condition is a factor that impinges on the cost performance of the input/output relationship, for example, the type of customer served or the energy density of the network.

While an output may loosely be described as a business condition, it is harder to argue that customer class or density are products or outputs.

Unless this distinction is drawn, analysts may claim that cost models have adjusted for variations in business conditions implying factors such as energy density when in fact the adjustment has related only to scale of output (GWh transported or customers served).

There is no existing protocol on the use of these terms but it is recommended that some uniformity be considered to avoid this confusion.

Generally efficiency is defined as using the minimal possible level of inputs to produce a given level of outputs however, measuring efficiency is more exacting. This is so in any industry where complex production procedures make it difficult to determine discrete inputs and outputs to ensure robust model specification.

Analysis of network efficiency must resolve an additional issue. There is no standard product or service.

Accordingly, the more recent empirical research while extending its analysis beyond the single energy output model, has yet to define an agreed framework for network outputs or 'product' and relevant business conditions.

In one of the better analyses of electric power distribution systems, Neuberg[19] observed:

"*Hopefully, someday functional form choice will grow out of a heuristic/theoretic investigation of the actual production process being modelled"*

Despite the elapse of more than 20 years since this was written in 1977, little scholarly investigation of the actual production process being undertaken in network services has been undertaken.

The most promising recent study, is that undertaken by PEG for a number of Australian DNSPs and discussed in a report *"The Cost Structure of Power Distribution"*[20] released in early 2000. Developing a conceptual framework for assessing the cost structure of power distribution the study was guided by the economic theory of economies of scale. This theory holds that the "the minimum total cost of an enterprise depends on the amount of *work it performs* - the scale of its output" and the prices paid for inputs.

This framework provides theoretical justification for the inclusion of three outputs in network cost analysis:

- energy throughput;
- customer connection; and
- distance transported.

Intuitively, this is a sensible approach. The justification for the use of distance is particularly appreciated by the industry as some empirical analysis undertaken in Australia has openly rejected the transport function of networks as a product of the network business. This is rather like comparing airfares between Sydney and Melbourne and Sydney with London and omitting consideration of the distance travelled.

[19] Neuberg, Leland Gerson, 1977 "Two issues in the municipal ownership of electric power distribution", Bell Journal of Economics.
[20] Pacific Economics Group, 2000 "The Cost Structure of Power Distribution".

Nevertheless the scale of network operations – or the amount of work performed - is just one dimension of the operating environment that may influence a network's costs.

Another dimension, and one that appears to be significant for assessing cost performance, is the type of network. Network type can be categorised by such business conditions as density and customer class:

- high energy density CBD services such as CitiPower;
- moderate density services such as the urban/residential networks of Energex or Energy Australia; *or*
- industrial/rural services such as Advance Energy or Ergon Energy.

Within the electricity industry energy density and customer class are widely recognised as major cost drivers.

Neither of the reports reviewed has progressed model formulation to the next level of rigorously assessing the relationship between costs and type of network. This is a particular disadvantage for Ergon Energy where the type of network appears to match or even outweigh the scale effects in its cost relationships.

2.5.2. Model Specifications

The PEG and TAP reports specify a simple cost function model founded conceptually in the economic theory of economies of scale. That is, network outputs have been defined in terms of the 'work performed' by the network and measured as energy throughput, customers served and network line length. As a measure of scale economies, the coefficients estimate the change in cost for a linear change in output. PEG extends the model to include a business condition variable, customer class defined as percentage of non-industrial customers served. The TAP model does not include business conditions though it does include a measure of supply reliability. PEG treats reliability separately in a stand-alone analysis.

There is some ambivalence in the use of the terms 'work performed' and 'business conditions' in the PEG report, and these are used interchangeably.

This has the effect of obscuring the distinction between scale or ‘output’ variables and business condition variables. Costs defined in terms of scale capture only part of the cost relationship since the outputs: customers, energy transported, and line length, *are not standard products.* PEG acknowledges implicitly that costs extend beyond scale effects to certain business conditions when it includes a term to define the impact of different customer classes. TAP does not extend its model beyond the scale variables, assuming by default that outputs have a standard or average relationship to costs.

Specified in this manner the models do not adjust for business conditions – only for scale, and in the case of PEG, for customer class.

Putting to one side the sophisticated techniques employed, in simple terms, the models have estimated an average cost associated with increasing each output by one unit. Each DNSP cost prediction is then estimated by multiplying the number of outputs by the average cost. Undoubtedly this adjusts for scale differences among the DNSPs but it cannot adjust for differences in the operating environment as required by the QCA.

Business conditions such as density or customer class are ratios. The cost estimation is a calculation based on linear terms not interactions. Claims to the contrary cannot be substantiated. In part, this outcome is explained by the use of terminology. If the scale variables are defined as business conditions, as they are from time to time, then it is not incorrect to claim that business conditions have been taken into account. However, it would not be correct to infer from this that business conditions such as energy or customer density, and customer class have been tested, aside from customer class in the PEG analysis.

In summary, the PEG and TAP cost estimation models predict the impacts of *scale* on costs but not the impacts of network *type*. It cannot be accepted that business conditions such as density have been tested adequately and found to be insignificant.

Section 3 will show that within the Australian networks it is possible to detect quite strong relationships between a number of network *type* variables and network costs. Principal component analysis of US IOU data also reveals a strong density component. This is discussed in Section 2.6.

There are a several reasons why these links have not emerged from the US analysis. Possibly the US networks have different cost relationships, in which case the usefulness of this sample as a benchmark for Australia's DNSPs is called into question. Alternatively, the specification of the model may have generated misleading coefficients and tests of significance due to the high degree of collinearity between the independent predictors. This aspect is discussed in Section 2.6.

2.6. Estimation Procedures

Defining cost relationships in terms of scale has significant implications for the robustness of the statistical models developed. Intuitively, costs are likely to rise in line with the number of customers served, energy transported and line length provided. It is also plausible to expect that there will be a relationship between the number of customers served and the amount of energy throughput. Analysis of the coefficients of correlation between these output variables supports this view. Refer Table 2.6.1-1 Correlation Matrix of US Investor Owned Utility data.

However, in statistical terms, the high correlation between these scale variables imposes constraints on the model specification which do not appear to have been accounted for in either model. Additionally, statistically significant predictor variables appear to have been omitted from the model PEG used to predict Ergon Energy's cost performance.

The PEG report states that:

"A branch of statistics called econometrics has established procedures for estimating the parameters of economics models."

The procedures developed to estimate parameters in stochastic models are used more widely in statistics than in just econometrics. Moreover, there are well established principles for model specification. In agreement with other authors of undergraduate regression textbooks, Weisberg[21], a widely respected authority on

[21] Sanford Weisberg, Applied Linear Regression, 2nd Ed., Wiley, 1985.

the topic of applied regression analysis, notes some basic principles of regression analysis. These include:

- Independent (or predictor) variables should not be highly correlated ie, collinear;
- Predictor variables with statistically significant coefficients should be included in the final model; and
- Predictions by the model should not be extrapolated beyond the range of the data.

2.6.1. Collinearity of Independent Variables

PEG and TAP appear to have based their analysis, and hence their findings, on a data set with collinearity problems. Collinearity, or multicollinearity, exists when there is a high degree of correlation between the independent predictor variables. Collinearity, is a common problem in time series where a common set of influences move together over time and are thus highly collinear. Scale variables also exhibit this tendency to move together. In this case, the parameters estimated for the predictors cannot be disentangled and their independent estimates cannot be obtained.

This creates a problem in regression analysis by artificially inflating the estimates of the error associated with the coefficients, invalidating the tests for significance. The PEG predictive model would actually perform better if one (or more) of the correlated predictors is dropped from the model.

Picket Fence Analogy

This is an analogy often used to explain multicollinearity in statistics text books is known as the picket fence analogy. Imagine balancing a flat sheet of wood, say, a tabletop, on 4 points, such as the legs of an inverted table. The four widely dispersed points would support the flat sheet. If however, the points were all in a straight line, like a picket fence, trying to balance the tabletop would be very difficult. Just as the picket fence does not provide a stable support for the tabletop, collinear predictors do not provide a stable set of predictors for a response variable.

Two of the key variables specified in the two models are highly collinear. Using data similar to that used by PEG **(insert footnote as to source of the data)**, it is apparent that throughput (GWh) and customer numbers (#) are correlated, with a value of 0·94 from Table 2.6.1-1. Both predictors are a measure of scale. Network line length (km) presents less of a problem, with correlation values between 0·75 and 0·81 between it and the other two predictor variables. Note that the predictor variables have been logged and standardised before the correlation matrix was calculated to accord with the PEG analysis.

	LogCirckm	LogCust (#)	LogGWh
LogCirckm	1		
LogCust	0.76	1	
LogGWh	0.81	0.94	1

Table 2.6.1-1: Correlation Matrix of US Investor Owned Utility Data

Based on scale variables that are highly correlated the coefficients estimated by the PEG model for the impact of customers and throughput on costs, and to a lesser extent line length, are unlikely to be correct. This has particular significance for the cost predictions since the weights used to construct the output variable are derived from this analysis.

2.6.2. Inclusion of Statistically Significant Variables

For reasons that are not explained, PEG has only included some of the parameter estimates in their predictive model though their own test against the critical value suggests that other terms are also significant.

The PEG report notes on pages 17-19 that the linear coefficients for the first order terms are statistically significant as their t-statistics are greater than the critical value of 1.645.

Using this same criterion, there are interaction terms and squared terms that are statistically significant that should have been included in the model. For example, the coefficient of the squared cost of labour term, LL, has a t-statistic of 4·02, which is greater than the critical value of 1·645. In fact, no interaction or squared term has been included despite their significance as predictor variables.

2.6.3. Extrapolating Beyond the Range of the Data

In inferential statistics, such as the PEG cost function model, coefficients estimated within a data sample are used to infer or predict performance either of a single business within the sample or of similar businesses not included in the sample. Extrapolating the model to produce estimates beyond the range of the data is not statistically sound. Again an analogy is a useful tool for explanation.

Children's Height Analogy

If the heights of a sample of children aged 1, 2 and 3 years old were measured, a dramatic increase in height with each additional year of age would be found. If this linear trend of growth and age were extrapolated, the model would predict that an average 20-year-old would be approximately 4 metres tall. This is nonsense. It is intuitively obvious that a model developed over the range of 1 to 3 years of age is only valid for predicting the heights of children between 1 and 3. This is called interpolation. Using such a model to predict the height of a 20-year-old is called extrapolation. Though the dangers of extrapolating infant growth rates are immediately obvious those of extrapolating implied energy densities are less so.

It is intuitively obvious that OPEX costs will increase with size. Both network length in km and throughput in GWh are measures of size. Figure 2.6.3-1 depicts a scatterplot of line length (Circuit km) and throughput (GWh), measured on a log-log scale. Size, or scale, is represented by position along the diagonal running from bottom left to top right.

Measured against either variable, Ergon Energy appears to lie within the sample. In fact, its throughput, log GWh of 9.5, lies close to the middle of the sample of US IOUs. It does have a large value of log Circ km (network length) at around 11.8, but manages to fit just within the range of the sample.

It is not until both variables are considered simultaneously, a measure of energy density (GWh/km), that a real measure of the difference between Ergon Energy and the other networks represented in the data set can be fully appreciated.

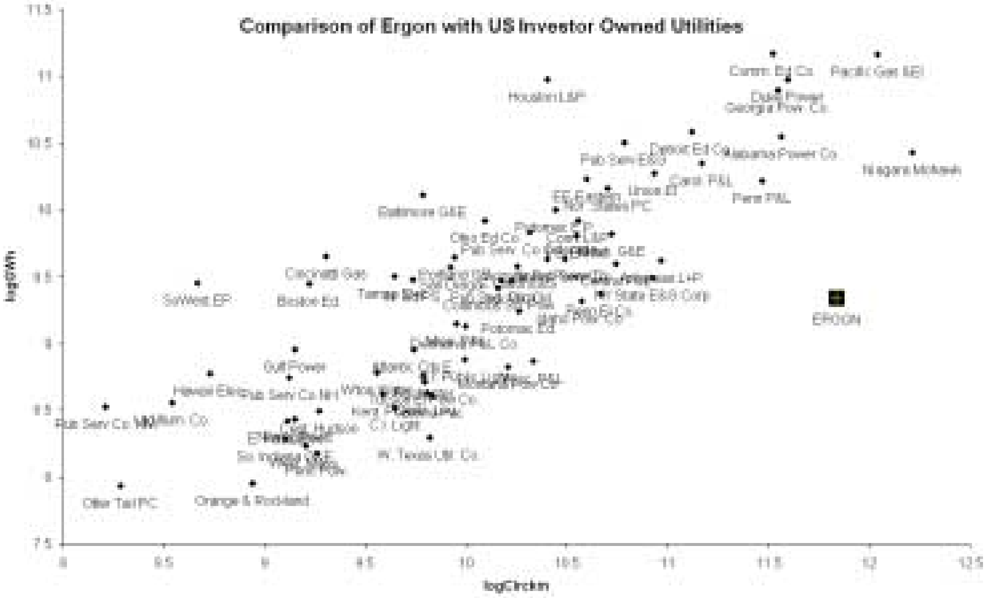


Figure 2.6.3-1: Scatterplot of Network Length versus throughput for US Investor Owned Utilities

The trend in energy density of the sample is indicated by the general cluster of networks around the diagonal. Networks with above average density are above and to the left of the trend with lower density networks below and to the right. Energy density of any one network is represented by the perpendicular distance of any network from the diagonal.

Note that Ergon Energy has a very low energy density, indicated by its position so far to the right of the main cloud of data points. Note also that the implied energy density of Ergon Energy is considerably less than that of its recommended peers for reliability standards, West Texas Utilities, Idaho Power Co and Sierra Pacific.

Given the ‘distance’ of Ergon Energy from the rest of the sample, it is unreasonable to expect a model based on US IOUs to accurately predict Ergon Energy’s efficient operating costs.

If energy density is a significant cost driver, it will not emerge as a linear effect of throughput or network scale, but as a significant interaction term.

The energy density of the sample also emerges from the interaction between throughput and distance in the Australian data. However, with a mixed sample of rural and urban networks there is no common trend in energy density. The scatterplot of OPEX costs and line length in Figure 2.6.3-2 shows clearly two distinct patterns of network density, a high density trend for urban networks and a low density trend for rural networks.

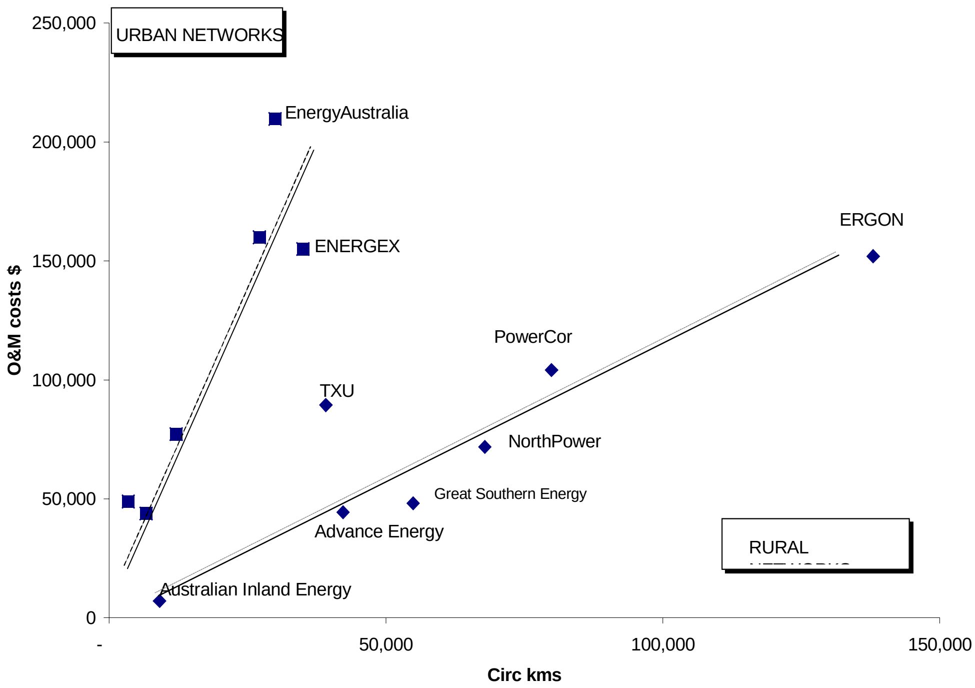


Figure: 2.6.3-2 OPEX Costs and Distance (Km Wires)

Though the difference between the rural and urban densities is large, a gap that is matched by the variation in OPEX expenditures measured per line length, the coefficients for the Australian comparisons have been drawn from the total sample. That is, the observable evidence that rural and urban networks face significantly different cost structures has not at any stage been factored into the analysis. The coefficients for scale are for the average, or standard, product.

The soundness of estimating a single parameter from what is obviously two independent cost curves must be questioned.

2.6.4. Addressing the Shortcomings

Of the shortcomings mentioned in the previous sub-section, the third is the most serious. The second can be addressed by re-testing and re-specifying the model.

One technique to address the problem of correlated predictors is to use principal components analysis and principal components regression.[22]

The matrix of correlations of a sample of IOU data is contained in Figure 2.6.4-1. This data set contains the variable peak demand, which was not considered in the PEG analysis, as well as throughput, customers and network length, which were included in the analysis. These data were then logged and standardised to accord with the PEG analysis.

22 Multivariate Analysis.

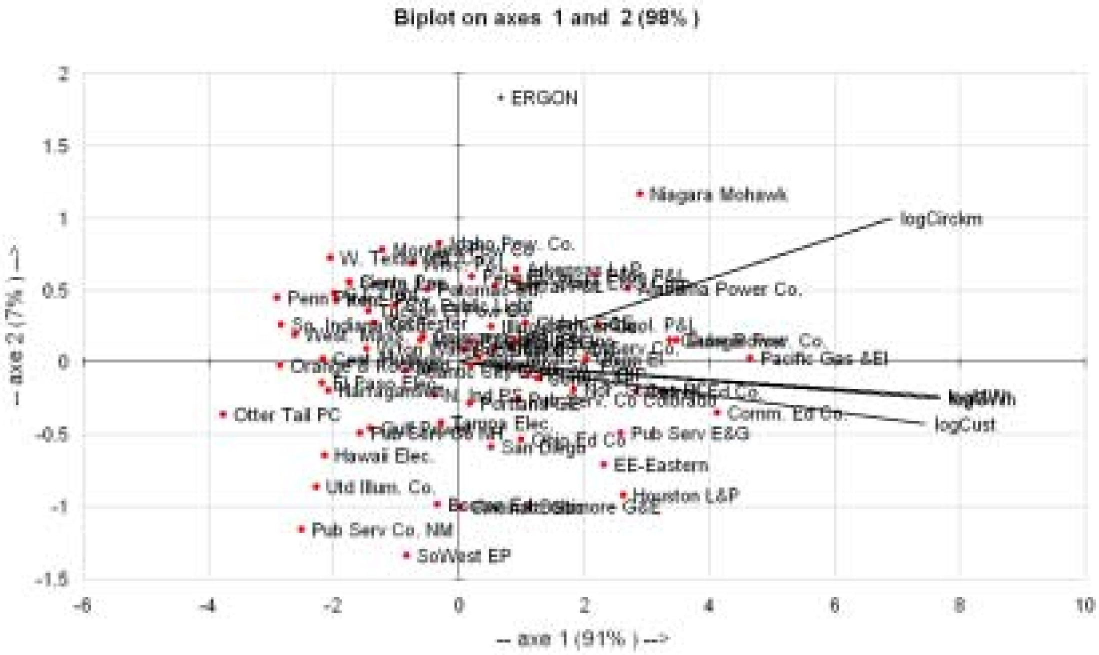


Fig 2.6.4-1Correlation biplot showing IOU data and Ergon, and the projection of the predictor variables.

This analysis shows that most of the variation in the predictor variables is contained in the first component, just over 90 per cent. This component is highly correlated with capacity, throughput and customers, and to a lesser extent, network length. We will call this first component *scale*.

The second component consists of a positive contribution from network length, and negative contributions from each of the other three original variables. It accounts for an additional 7 per cent of variation. We could call it energy density, or customer density, or capacity density, but it is easier to just call it *density*.

The analysis shows that there are only two significant components of variation in the source data, and that they account for 98 per cent of variation therein.

Points to the right of 0 on the x-axis indicate a large IOU, a point to the left indicates a small one. Points below the 0 on the y-axis represent an IOU with a very dense network, points above the line represent an IOU with low density. The biplot shows even more dramatically how unusual Ergon is compared to the US sample.

Note that both these principal components are significant predictors of the number of employees, a proxy for OPEX costs. The first, scale, is the most significant as would be expected. But the second principal component in particular, which represents density, has a t-statistic greater in magnitude than 7. This is for US IOU data only.

2.7. Application to Ergon Energy

To estimate efficiency and reliability gaps the TAP and PEG reports compare the performance of Ergon with a number of cost and reliability benchmarks. Two benchmarks used are the “Best Australian Performer” by TAP and the “Top Quartile of USA DB’s” by PEG.

This review has shown that the use of an inappropriate database to estimate the coefficients in the US study has generated estimates and predictions that are of little relevance to comparative performance assessment for Ergon Energy. Recall that the infant growth rate is of little value when predicting adult height. The QCA explicitly called for estimations of potential efficiency improvements measured against suitable peers. US IOUs do not represent a sample of networks that equate to Ergon Energy. The TAP report uses a best performer approach for each of the partial performance categories selected. This is in effect a “cherry picking” approach and compares Ergon with a fictitious organisation, one that would be ‘best’ in all categories. The use of terms such as ‘best’ and ‘worst’ in a context where outcomes may largely be influenced by business conditions or accounting practices is questionable.

Further, in many instances, improved performance in one category may be to the detriment of performance in another category. For instance, OPEX expenditure may be high to provide greater reliability. This is certainly the case in the CBD/urban networks that exhibit high levels of OPEX expenditure per km relative to the rural network services.

This comparison approach was rejected by the Office of the Regulator General with regard to the UMS report of Operating and Maintenance Cost Benchmarks, January 2000.

Reflect on the message conveyed in Figure 2.2-3. If Ergon Energy is to achieve the estimated efficiency gap in OPEX costs, it needs to operate a network 75 per cent longer than Powercor for the same level of OPEX expenditure.

3. AN EXPLORATORY ANALYSIS OF AUSTRALIAN DISTRIBUTION NETWORK COSTS

This section explores more closely the relationships between network costs, outputs, and business conditions.

One hurdle to developing a robust model specification for electricity networks has been a lack of an acceptable theoretical framework to justify the inclusion of a number of possible cost drivers. Production theory assumes that *outputs* are produced from a given array of paid inputs: the theory underpinning the PEG cost function model. Non-traditional variables such as the business conditions of density and customer class are not considered easily accommodated within this structure as they cannot be regarded as outputs per se.

Treated as interaction terms, or second order variables they often appear to provide less explanatory power than the first order ‘output’ variables. Accordingly, it is assumed that these conditions are not significant determinants of costs and omitted from the models. For example, energy density from the PEG model, and both energy density and customer class from the TAP analysis.

While ‘customer class’ may not appear to be an output requiring paid inputs, defined as ‘high/low voltage supply’, it presents as a variable seemingly appropriate to the definition of output requiring paid inputs. Technically, there is a significant different between the network supply to residential customers and, say, large commercial customers. Though energy per se may be considered a standard product the same cannot be assumed for the service which transports it.

Those responsible for the development and maintenance of distribution networks hold these business conditions to be among the key drivers of asset investment and operation and maintenance expenditures. Models limited to the assessment of the impacts of operational scale only, have provided inaccurate and misleading comparisons of networks for a great many years.

The analysis discussed in this section was undertaken to progress understanding of these interrelationships. It seeks to identify possible links between input costs and business conditions by investigating operating parameters of a number of Australian networks. Using a series of scatterplots to test relationships it reveals strong trends between a number of business conditions and key variables. Taking the analysis to the next level, these trends were investigated for evidence of possible causal links between paid inputs and the array of business conditions.

It is neither exhaustive nor intended to suggest that all the relationships are statistically significant. Nonetheless, the evidence of strong relationships in a number of the key areas does suggest that simple output models do not capture the full impact of business conditions on network costs.

The data covers 13 Australian distribution networks and has been taken from published regulatory data. As the number of networks in the sample is small, the intention is not to estimate statistical parameters of the linkages but rather to investigate the nature of the cost drivers. In the words of Neuberg, the objective is to commence "a heuristic investigation of the actual production processes being modelled."

The patterns emerging from the investigation of these factors are clear and unambiguous. Certain business conditions show quite distinct links with various cost measures. The challenge is to define these factors in terms that are appropriate for modelling purposes. Performance analysis that does not adjust for business conditions that impact closely on paid inputs will not present an accurate assessment of network efficiency.

The figures used to illustrate observations in this Section are presented in Appendix A – Cost Driver Analysis Charts.

3.1. Network Costs and Network Outputs

O&M Costs and Outputs

Figures 1, 2 and 3 present scatterplots of O&M costs relative to the three outputs identified in the PEG and TAP models: energy delivered, customers served, and length of lines. As could be expected costs rise in line with the amount of service provided. The relationships of costs to throughput and costs to customers served is linear over the entire sample. However, the relationship with line length is not (Figure 3). Two distinct categories of network density and O&M costs emerge: dispersed rural with lower costs and longer line lengths and higher density urban with higher costs.

Variation in the spatial characteristics of the networks has been accepted as a determinant of costs by the Australia regulators. Implications for relative network cost levels have been factored into pricing determinations in both NSW and Victoria. The lack of a robust database has to date precluded any statistical estimation of these impacts and allowances, are at best, guesstimates.

Ergon Energy sits generally on trend in these series. Its relatively higher costs per customer (Figure 2) appear to be driven by the length of the network required to service its relatively small customer base (Figure 3).

O&M Costs and Partial Productivity Measures

In adopting the building block approach to regulating network prices economic regulators have treated each block as a separate cost category. Each block is assumed to be independent of the others and of the nature of the network.

A closer examination of the data shows that this assumption is not soundly based. Quite fundamental factors aside from managerial efficiency may drive differential outcomes in each building block, and also in reliability. Expenditure above or below the industry average in a particular cost category may indicate a superior or poor performance, or it may reflect the advantages or disadvantages of a particular customer class or load density.

To illustrate the lack of independence of cost components the trend between customer density and the proportion of total costs devoted to O&M is depicted in Figure 4. In general, as customer density increases the level of expenditure on O&M relative to total costs will decline.

It is not uncommon practice for efficiency of cost performance of the DNSPs to be assessed by separately comparing its O&M, capital expenditure, or reliability against such normalising factors as output, customers, or line length. The network achieving the lowest ratio for each of the indicators is assumed to be the most efficient. Other DNSPs are encouraged to meet this level of ‘best practice’ performance. Indeed, regulated expenditure levels have been set to achieve this outcome. This partial analysis to assessing productivity performance creates difficulties when comparisons are made across different scales and types of networks. A feature inherent in the building block approach.

Figures 5, 6, 7 show separately each of these indicators and the impact of business conditions on relative performance. If O&M per GWh throughput rises and falls with business conditions so too will CAPEX and assets.

Pulling these indicators together the performance of a selection of DNSPs normalised against the three key outputs: customer numbers, line length and GWh throughput is depicted in Figure 8. The variations against the different normalising factors reflect different operating scales and types of network, not necessarily efficiencies. Ergon Energy could be considered relatively efficient measured against cost of km but inefficient against cost of customer. Only after adjusting for these influences can the true level of efficiency be determined.

As the largest of the rural DNSPs Ergon Energy correctly may be compared to its rural peers, not to the urban ENERGEX.

3.2. O&M and CAPEX – Efficiency or Accounting Practices?

Lack of independence between the cost categories is not the only factor that can influence the reliability of comparisons based on partial measures. Another influence is the possibility of differing accounting treatments affecting asset valuations and allocation of expenditures.

Figure 9 suggests that the Victorian and New South Wales DNSPs may be operating under different accounting regimes. All Victoria businesses appear to be operating at a higher level of CAPEX to O&M costs than those in NSW. This may, of course, be due to fundamental differences in the network configuration, but it does suggestion caution in simple comparisons.

O&M Unit Costs

O&M Unit costs and scale – Costs per unit of output are frequently used as a measure of performance. However, comparing any cost component against throughput is not recommended as a reliable indicator of efficiency performance. More likely it will reflect the benefits of scale. Cost advantages from scale are discernible in Figure 10. Large urban networks achieve considerable cost advantages relative to the smaller rurals. The US data for the peers nominated by PEG for Ergon Energy and ENERGEX have been included to show the consistency of this trend.

Note that for the same level of throughput the small urban Victorian networks have lower O&M unit costs than, say, Powercor or NorthPower reflecting the lower O&M/GWh cost base of the urban networks. Neither PEG nor TAP have included adjustment for energy density in their analysis.

O&M Unit costs and customer class - Customer class is a significant cost driver of unit costs. Higher load factors typically associated with industrial and commercial customers imply higher levels of capacity utilisation allowing DNSPs to deliver more output for any given level of cost, unit costs would be expected to be lower. Figure 11 depicts the inverse trend between high per customer consumption levels and lower unit costs.

Note, that this relationship is not linear. The rural DNSPs with mostly smaller customers sit at the high cost end of the curve. The urban DNSPs with larger average consumption levels enjoy the benefits of lower costs while at the higher levels of demand associated with large industrial customers, costs tend to rise again: Australian Inland Energy, Advance Energy and Ergon Energy.

Conversely, residential loads, particularly those with a high summer air-conditioning component, exhibit poor load factors and hence low capacity utilisation rates. Network investment to supply the peak demand of a few summer months can sit idle during winter. This is particularly relevant for networks in South Australia and Victoria where the winter heating load is largely met by gas.

Using output (MWh) alone to assess relative cost performance can therefore be misleading. A network service provider has little control over its customer load and consumption levels.

Units Costs and Density – As a spatially determined production unit, the costs of a network service business are highly likely to be influenced by the interaction of output and size of territory, that is, energy or customer density.

Among the Australian sample used for this investigation the DNSPs fall neatly into two discrete classes, rural and urban. The average number of customers per km of line for the urban networks is around 35 but only around four for the rural networks such as Ergon Energy. Viewed in terms of resources required this means that a rural DNSP must service and maintain up to 250 metres of line for each customer connected in contrast to an urban network which needs to service only 25 metres.

It does not require extensive calculation to determine that rural costs are likely to be comparatively higher than urban costs.

Figures 12 and 13 (O&M unit costs and energy and customer density) show this relationship clearly. Estimating a statistical relationship for rural networks using the IOU sample in the US or the combined urban/rural sample in Australia is inappropriate.

The main impact of energy density on costs appears to be in the distinction between rural and urban networks. Factors other than density contribute to cost variations once the rural and urban DNSPs are assessed separately.

3.3. Networks Costs and Business Conditions

Customer Class

Customer numbers is a major cost driver. The nature of the load (customer class measured as kWh/customer) has a strong influence upon the type of asset and the level of investment and, and hence the level of maintenance.

In general, the larger industrial and commercial customers (proxied by high levels of consumption per customer) require higher levels of asset investment compared, say, to residential customers. Figure 14 shows average consumption levels relative to assets per customer and confirms a positive association between larger consumers and higher asset investment.

Interpreted as customer class, consumption levels are treated as business conditions. However, if instead class was defined as high or low voltage services each ‘class’ would more appropriately could be considered a paid output. That is, the network service delivered is not a standard product and the product can be differentiated by the class of customer it serves.

Of particular interest is the implication of customer class for the type of asset investment and the concomitant requirement for O&M and capital expenditures. Large customers require larger transformers and substations and greater reliability. Quantitative analysis of the link between reliability and cost is proving elusive. But if multiple circuits, shorter line lengths, and greater redundancy are required to provide higher levels of reliability it is to be expected that the outcome will be greater investment.

Load Density: MWh/km, Customers/km

The other major cost driver is load density, measured either as customers or energy per line length. Any increase in energy density will be matched by a commensurate increase in the assets required per line length to supply that service. The most prominent example of this relationship is the relatively higher level of assets required by CitiPower to supply its purely CBD service territory (Figure 15).

Note again the distinction between the urban and rural DNSPs. Networks either invest extensively in relatively low grade systems to supply service in rural areas or in less, but more high grade facilities in the urban areas.

…and back to O&M costs

Maintenance expenditures can be expected to reflect the level of asset investment. As the length of line, number of substations, and transformers installed rises the resources required to manage these assets must also rise. Figure 17 confirms this association.

Finally, Reliability

Reliability is an output. Indeed with the emergence of the e-economy it is an output of increasing significance to a growing number of customers. A high level of reliability requires significant investment. Higher reliability tends to be associated with the higher density areas where the level of throughput can justify the assets investment.

Lack of adequate reliability data has precluded the integration of reliability into appropriately structured costs models. Models that purport to assess reliability, but which do not include adjustment for business conditions are misleading.

Analysis of SAIDI reveals an association between rising levels of reliability and shorter line lengths (Figure 18). This link is statistically significant at the 95 per cent confidence level. More importantly in the context of the targets nominated for Ergon Energy, the difference between the rural and urban DNSPs for levels of

SAIDI is significant at the 99 per cent level. To achieve the level of reliability of a DNSP that exhibited urban/rural characteristics Ergon Energy would be impelled to lift investment quite substantially. For example, the single line feeders to the inland centres would need to be duplicated at not inconsiderable expense.

3.4. Conclusion

Despite a history of economic analysis of the efficiency of electricity utility performance it is only recently that research has been directed to stand-alone network service businesses. Network businesses are not well understood. There has been little research into the unique features of stand-alone network businesses or likely cost drivers and their relationship to key input categories. Analysis tends therefore to be based on assumptions that are untested.

Performance benchmarking for regulated price setting must be grounded in a more rigorous assessment of the interrelated factors than has been undertaken in empirical analyses to date.

4. ASSET MANAGEMENT

The Ergon Energy network faces a different operating environment, community risks and customer focus to the DNSP's with which it is being compared.

The network is an amalgamation of six (6) smaller businesses covering geographically and demographically diverse areas with some of the smallest populations per square kilometre that would be found in the world.

The organisations could not individually afford a strong network planning and standards group and different work practices and standards developed across the businesses.

The network suffers from non-standardised approaches and data in disparate systems is not current or consistent. Therefore asset reliability and degradation is difficult to determine. Ergon Energy does not have sufficient history of the assets in the areas of reliability, efficient renewal costs or accrued maintenance debt to facilitate optimising the relationship between OPEX and CAPEX expenditure and business risk.

The above is compounded by different types of areas within the network, namely coastal strip and industrial compared to rural and remote. These differing areas have different growth rates and cost drivers.

The network also supplies to rural and remote customers and obligations imposed by government impact significantly on the performance statistics.

Ergon Energy needs to undertake additional OPEX costs in order to correct this situation and has identified major projects and prepared a business plan in relation to asset management to develop the skills, information and systems to facilitate long-term network optimisation and rationalisation. Refer Appendix B Asset Management for full detail regarding the asset management strategy.

The QCA therefore needs to take into consideration the asset base and the condition of that base. Comparisons of Ergon Energy to other DSNP's without such consideration lead to revenued reductions which actually limit the quantums and rate of savings achievable by the network.

The network asset base is particularly large and due to the range of population density covered, the network does not have consistent load requirements. The network is a series of long radical feeders and not a close interconnected network which affects both reliability and efficiency issues.

Due to differing capital and operating strategies across the regions some assets in various locations have become rundown over time. The deferral of renewals in the business has resulted in a maintenance debt which is difficult to quantify. This has led to an increase in OPEX as the asset base becomes less efficient to operate.

In general terms there needs to be an increase in the level of asset replacement and renewals over the next 3 years to in turn drive reductions in OPEX (significant savings may not be realised until then).

In order to run an efficient network Ergon Energy will need to demonstrate that the CAPEX expenditure is prudent based as a knowledge of :

- The network performance (reliability, utilisation and capacity);
- Risks involved in delays to expenditure;
- Efficient construction and renewal costs; and
- Trade-offs between operating and maintenance expenditure and capital costs.

To demonstrate the prudency of the CAPEX budget, Ergon Energy will need to undertake 'whole of life' cost analyses on the assets for different operating and renewal strategies by asset type.

This will only be possible once operating, maintenance and reliability data (in the appropriate format) is collected on the assets.

Reliability improvement will require a consistent set of definitions and data to track down problems and provide whole of life cost solutions.

Reliability targets will also involve work practice changes. This will require, for instance, reducing the interrupted supply minutes by:

- Better planning;
- Maximising line work;

- Adjusting the capital program.

Therefore, this will initially require CAPEX investment to provide a more reliable and robust asset as well as one-off OPEX costs.

In the absence of appropriate risk information, Ergon Energy cannot be sure that the current maintenance cycles are appropriate to address all the service delivery, safety and commercial risks on the assets.

Assessment of asset risks is a necessary pre-requisite to optimising the OPEX and CAPEX mix and determining the level of CAPEX required.

The asset condition is generally considered poor across the network. As mentioned previously, Ergon Energy do not have the ability to improve the utilisation of the assets without the expenditure of CAPEX which will have a delayed impact on OPEX.

The outcome will be that OPEX will remain above benchmark when comparing Ergon Energy's OPEX to a denser network with higher capacity.

This aspect in effect is a major difference between Ergon Energy and Energex. Consequently, Energex is in a better position to move to best practice and achieve the OPEX savings proposed.

Energex is a different network and types of initiatives required to move to best practice start from a higher base in relation to the maintenance planning and CAPEX programs and the capability to more fully integrate their asset management functions.

Ergon Energy on the other hand will require a phased lead in to price reductions if the OPEX savings are to be realised. The network organisation restructure needs to be completed including the implementation of the Asset Owner/Asset Manager/Service Provider design.

Asset management support systems and associated processes need to be established and consistent across the six regions. In relation to asset management processes, this includes the identification of processes, their redesign and standardisation, the identification of a required support system and tools and the implementation of the new processes.

Specific Issues

Policies and Procedures

Ergon Energy's safety problem has become worse requiring effort in cultural change, training and work practices.

Stakeholder Requirements

Ergon Energy's stakeholder requirements are as follows:

- Return on asset;
- Public safety;
- Reliability;
- Minimisation of CSO's;
- Utilisation – remote area supply process and electrification of remote locations;
- Employment for rural Queenslanders.

These stakeholder requirements and key performance indicators are in some respect opposed to the economic regulatory drivers. Consequently, these issues such as the Government accepting lower rates of return are detailed in the next sections of the report.

Conclusions

The following conclusions can be drawn for Ergon Energy. There will be a need over the next 2-3 years to:

- Increase CAPEX for renewals and reinforcement of the network to decrease OPEX in the medium term and increase network reliability.
- Develop an overall network strategic plan and supporting sub-plans.
- Standardise procedures, clarify the roles and responsibilities of the various parts of the organisation with respect to managing the assets.

- Influence the culture of the organisation towards one of an asset manager and service provision.

- Implement systems to support the above.

- Change work practices to improve responsiveness and reduce SAIDI minutes per annum across all customer groups.

- **Implement changes to the EBA's consistent with the above.**

- Review the locations and needs for the number of depots (140 depots) situated throughout Queensland consistent with the above.

Many of the above will require detailed consultation with the shareholding Ministers and need to be taken into account when setting regulated OPEX expenditure limits. Some of the requirements of the Regulator may not be consistent with Government policy (regional employment for Queenslanders etc).

5. APPLICABILITY OF TARGETS

5.1. Fit for Purpose

The TAP and PEG Pre-Determination Reports do not provide detailed process level benchmarking to indicate where the DNSPs can improve their performance and the sustainability of their forecasts. The subsequent report by TAP and PEG regarding Achieving Identified Savings in OPEX proposes to benchmark OPEX sub-functions against USA comparators, however, as outlined in the previous analysis, this approach is questionable given the statistical incompatibility of the comparators proposed and the inability to allow for business conditions.

The focus of most process level benchmarking studies is on using quantitative benchmarks as signposts, identifying areas where gaps may exist, and where opportunities for improvement may be found. The importance of the benchmark value diminishes once an area of potential improvement is found.

Implementing better practices leads to performance or efficiency improvements. Assessment of the operational implications of improved practices is needed to establish quantitative improvement targets on a case by case basis. This is the essential role of, and value in, process level benchmarking.

System engineering is a field of study that focuses on the inter-relationships between processes and the assessment of the resulting whole. A fundamental premise of system engineering is that the performance of a system is not equivalent to the sum of the performance of its parts. The same concept is applied in economics and in assessing organisational performance. The approach taken by TAP and PEG as outlined in Section 2 does not accurately assess the overall efficiency or performance of Ergon Energy as a distribution business. It is not fit for the purpose for which it is intended.

Furthermore, the aggregate view does not allow detailed assessment as to:

- Factors which are outside management control.
- The ability and timeframe of Ergon Energy to meet the proposed targets.

5.2. Efficiency Issues

The efficiency of any industry will improve over time. However, the rate of improvement in future years cannot be predicted by using a linear extrapolation of previous improvement. Fundamentally, only four events can improve efficiency:

- Technological change.
- Structural reform (industry or regulatory).
- Internal reform (strategic, industrial or organisational).
- Continuous improvement processes.

The first three events typically generate significant efficiency improvements (step changes). However, they typically occur only periodically. Large improvements made in the period of significant change or reform are not repeatable after the change has occurred or the reform completed. In between major events, most industries adopt a continuous improvement model that delivers regular, but moderate, efficiency gains.

A number of overseas reports regarding post privatisation efficiency improvements in both the electricity and water industries suggest that long term sustainable productivity improvements, or cost reductions, varied from 2% to 4%[23].

The TAP and PEG reports present no evidence in support of their assertion that the electricity industry will continue to reduce unit cost rates by a constant even percentage per annum. The lack of supporting evidence raises significant doubts as the accuracy of the prediction.

One of the most significant issues that must be discussed is that the PEG report appears to establish a link between what could be defined as *industry improvements*, and those improvements that any individual organisation can achieve.

The ability of any individual organisation to improve its efficiency is controlled by both external and internal factors including:

[23] Reference Reports by IPART Efficiency Benchmarking of Electricity Distributions, Discussion Paper, February 1999 and OFWAT.

- Regulatory and legislative framework (including industrial relations regulations).
- Contractual arrangements (with its staff, customers and suppliers).
- How current and inherently efficient its asset structure and technology is (and the availability of capital to change it).
- How effective its management structures, processes and practices are.

The first factor is external and not under the direct control of the organisation. The second and third factors are controlled by the organisation but are usually constrained by legislation, ownership or regulation. Furthermore, in many cases, they involve multi-year arrangements that may prohibit significant change in the short term. Only the last factor can be reasonably managed to achieve short-term improvements. If an organisation already does not have moderately efficient management structures, processes and practices, productivity improvements of the magnitude and timing suggested by TAP and PEG are impossible for Ergon Energy as compared to ENERGEX.

Examples of Productivity Improvement

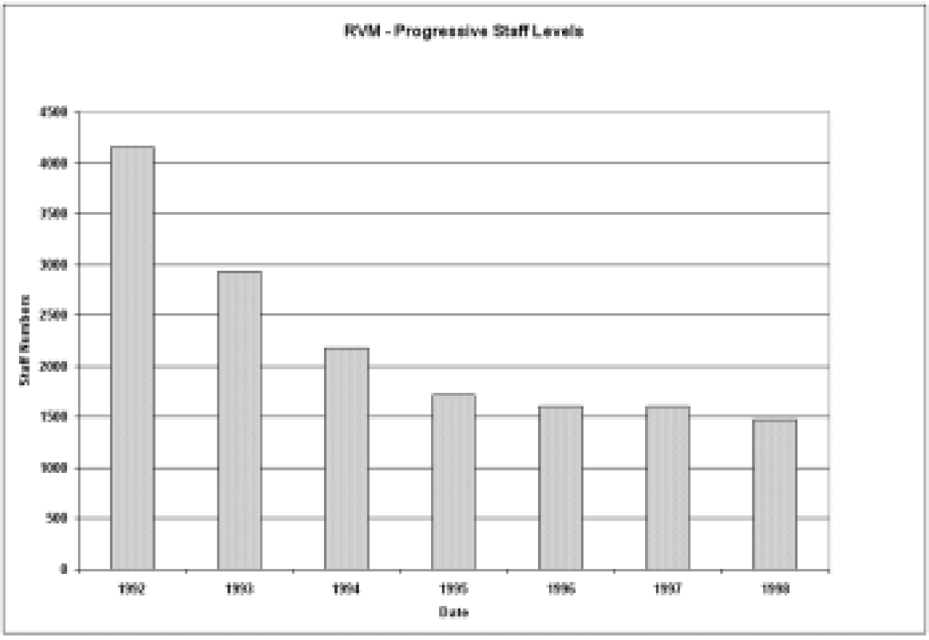
A number of examples of productivity improvement are presented below. Data relating to efficiency improvement rates has been collated to show that rates tend to plateau after a few years and in fact the cost curve can be an initially steep curve after restructuring has commenced, then flattening. Further improvements come from step changes whereas the total productivity factors measurement generally assume even rates of improvement.

Restructure in the Rail Industry

Indec Consulting, between 1992 and 1999, was involved in the restructure of the rail rollingstock maintenance and operations divisions of Australian National Railways (freight and suburban rail SA and Tasmania), The Public Transport Corporation (suburban rail Melbourne), Queensland Rail (freight and suburban rail workshops), State Rail Authority (urban rail maintenance and operations Sydney) and Westrail (freight and suburban rail W.A.).

These assignments were major restructures involving savings of the order of $30M to $100M per annum of recurrent OPEX costs over a 5 to 7 year timeframe.

The following is a typical example of the rate of productivity improvement experienced during the above assignments by showing staff numbers at the start and finish of the rationalisation process for the rail vehicle maintenance (RVM) function of one of these assignments.



Graph 5-1 RVM – Progressive Staff Levels

The percentage decreases for RVM during the rationalisation period are shown in Table 5-2 below.

Year	Staff No	Staff Reduction	% Reduction
1992	4153	Nil	Nil
1993	2941	1212	29.2
1994	2177	764	18.4
1995	1711	466	11.2
1996	1607	104	2.5
1997	1520	87	2.1
1998	1477	43	1.0

Table 5-2

Note – The 1997 and 1998 Staff Numbers are estimates including estimates of Staff used by outsourcing companies

The efficiency reform process resulted in a staff reduction of 35% over 7 years, however the rate of efficiency gain was not the same percentage rate on a yearly basis.

The significant impacts in years 2-3 were initiated by the Government funding redundancy packages in that the savings could then have a more immediate impact on the cash flow and the change reform could be maintained. In the example shown since 1999 maintenance cost remain in the 1-2% range and are forecast to do so until new rollingstock (CAPEX) is scheduled to be introduced commencing in 2003.

IPART Data – NSW Electricity Distributors

The material is this section has been sourced from the Independent Pricing and Regulatory Tribunal (IPART).[24]

"As shown in Table 5-3 below, labour productivity (calculated as real revenue per employee) improved by 32% in real terms over the period 1995 to 1998. Due to the effect of contracting out, the trends in labour productivity should be interpreted with caution.

		1995	1996	1997	1998	% Change 95-98
Labour Productivity	$	404	443	504	533	32
% Change on previous year		0	9.7	13.7	5.7	
Operating and maintenance cost	$M	663	659	646	679	3
% Change on previous year		0	-0.6	-2	5.1	
Operating Cost per customer	$	248	239	233	241	-3
% Change on previous year		0	-3.6	-2.5	3.4	
Operating Cost per circuit km	$	2,446	2,429	2,386	2,444	
Operating Cost per MWh sold	$	16	15	15	16	0

Table 5-3 – Efficiency and Productivity Measures (1998 prices)

Note 1: Labour productivity is calculated as real revenue per full time equivalent employee.
Note 2: 1996/97 operating expenses include network and retail business expenses but exclude costs incurred by non-core businesses of the distributors as disclosed in the regulatory accounts returned to IPART.
Note 3: Operating and maintenance costs exclude depreciation and interest expenses.

[24] Reference - Efficiency and Benchmarking of NSW Electricity Distributors - Discussion Paper, DP33, Page 7, February 1999.

Excluding operating expenses relating to the distributors' non-regulated businesses, the operational efficiency of the distributors also improved over the same period as reflected in lower operating costs per customer, circuit km and MWh sales. These are shown in the Table. As illustrated by these partial productivity measures, NSW DNSPs have achieved substantial efficiency gains in recent years. The Tribunal will consider these gains in its review for pricing for transmission network services".

It should be noted that in 1998 the operations and maintenance cost changed upwards from previous downward trends in all categories measured.

England and Wales

Total Factor Productivity (TFP) indices have been used to measure improvement trends in the electricity DB's in England and Wales.

Using the Malmquist TFP indices, the average improvement in England and Wales for the period 1990/91 to 1996/97 was 3.5%.

It should be noted that the rate of change was not noted and that the DNSPs in the UK model were rationalised under a straight line customer relationship compared to Australian DNSPs many of whom have triangular relationship customer functions as well.

Water Industry - UK

A report commissioned by OFWAT in the UK **predicted** that reductions in real operating costs of 2.5 to 3.5% a year could be achieved in the industry for the period.2000-05. Total Factor Productivity was used and covered all inputs including capital, energy and materials as well as labour.

A quotation from the report indicated that industries doing similar tasks and other privatised industries showed an average TFP improvement of 2–3% a year over a long period of time.

Productivity Improvement Summary

The above examples given demonstrate the need for greater identification of the potential for justifying savings (other than the TFP approach involving benchmark comparisons against DNSPs who have already undertaken significant reform). Predictions therefore need to consider where an organisation is on the cost curve and consider the rate of improvement that can be achieved.

5.3. Inter-Dependence Issues

Measuring the performance of a distribution business is a complex undertaking. Assessments must consider both cost efficiency and service level performance and must acknowledge a number of inter-dependencies. Inter-dependencies that include:

- Maintenance cost and prevailing asset age and condition.
- Network configuration and maintenance costs.
- Customer service standards and operating costs.
- Network performance, operating costs and maintenance costs.
- Network performance, network configuration and design standards.
- Operating costs and customer class numbers.
- Operating costs and regulatory/ownership requirements.

Whilst the TAP and PEG report does acknowledge some inter-dependencies, and attempts to adjust for these several significant gaps exist:

- The TAP and PEG methodology does not take into account consideration of customer class, density and business conditions.
- TAP and PEG's data and analysis does not take into consideration the age or prevailing condition of Ergon Energy's asset base and size of the network relative to comparitors used.
- Customer service standards beyond SAIDI, CAIDI, SAIFI, and MAIFI that impact upon operating costs.

- The relationship between CAPEX and OPEX costs.

5.4. TAP Report

TAP state in their report that the gap to Best Australian Practice can be closed in a number of ways:

"It should be noted that the reduction in unit OPEX costs could be achieved in a number of ways. Apart from the obvious way of output remaining unchanged and OPEX costs being reduced by 15 per cent, ***it could also be achieved by OPEX 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 OPEX costs are held in check. It should be noted that Ergon has a relatively poor reliability record which 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".*

The QCA overlooks the growth and reliability aspects in the draft determination as it focuses soley on OPEX cost reduction and QCA have not considered the alternatives to reducing the gap to best practice. QCA are not linking other issues with pricing such as one-off restructuring costs, the restructuring required and the issue of holding prices whilst restructuring occurs and growth and improved reliability increasing input efficiency during the initial restructure period.

Demand Growth

GHD are forecasting 3% growth per year for Ergon Energy. If this holds true, then Ergon will close the gap to best practice in 6 years, without any reduction in OPEX or improvement in Service Quality.

Growth	Gap to BP Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
3%	12.40%	9.86%	7.39%	4.99%	2.65%	0.36%
1.5%	13.68%	12.38%	11.10%	9.83%	8.58%	7.35%

In addition the QCA is estimating only 50% of the growth is directly related to OPEX expenditure (without detailing justification for this decision). In normal circumstances of a fully optimised network without maintenance debt this type of estimate may be reasonable. However, as outlined in Section 4 of the report, Ergon Energy is not that type of a network and the QCA assumes scale economies that require one-off OPEX investments in Asset Management processes. Accordingly the QCA estimate could be too low as the state of the network is not factored.

Service Quality Improvement

Service Quality is an important issue to both Ergon and its customers. Both TAP and PEG have highlighted the issue of poor service quality. Ergon is committed to delivering improvement in this area. Service quality is a part of the best practice benchmarking factors. Therefore, service quality improvement should be included in calculations as a means of closing the gap to best practice rather than relying purely on cost cutting.

We have modelled the Fisher ideal index, and our analysis suggests that Ergon Energy can close the gap to best Australian practice somewhat through Service Quality improvement.

SAIDI Improvement per year	Gap to BP Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
4.5%	14.22%	13.44%	12.66%	11.88%	11.10%	10.31%

However, we would note that reliability improvements as a measure to OPEX efficiencies are extremely unreliable. Reliability is driven mainly by CAPEX which in turn is a major driver of OPEX.

Both Growth and Reliability Together

If both projected growth at 3% and Ergon Energy’s Service Quality improvement targets are taken into account, Ergon will reach best Australian practice at the end of the regulatory period.

SAIDI Imprvt	Growth	Gap to BP Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
340-260	3.0%	11.09%	7.47%	13.99%	0.70%	1.57%	-3.78%
340-260	1.5%	13.6%	9.94%	7,58%	5.37%	4.16%	2.974%

Conclusion

It is evident that QCA failed to take into account these improvements in performance. We strongly recommend that QCA fully explore the possibilities of using growth and service quality improvements as opposed to cost reduction to close the gap to best Australian practice.

5.5. Potential for Improvement in Best Practice

In the paper "Potential for Improvement in Best Practice in Electricity Distribution",[25] TAP and PEG conducted a survey on pure technical efficiency and the impacts such improvements would have on electricity distribution unit costs.

The survey results suggest such improvements may generate small reductions of around 1% in OPEX cost over the next five (5) years. However, as the number of respondents was low and as they may have not appreciated the issue being surveyed, TAP and PEG conclude it would be inappropriate to incorporate any identified improvements in best practice in any unit cost target during the current regulatory period.

It should be noted that the survey results of reductions in unit costs included areas of improvement in relation to the following:

- Vegetation control, including targeted vegetation management and asset management.
- Labour productivity, including process improvement, performance based pay, live line working, multi-skilling and data transfer.
- Other, including risk management, asset conditions prediction, asset management systems, modelling of assets to optimise CAPEX, fault costs analysis and monitoring system components.

The sources of improvements in best practice as detailed in the TAP and PEG improvements papers are all incorporated in the step change improvements as outlined in the analysis of the ability of Ergon Energy to achieve the proposed OPEX targets in this report. The restructuring and asset management changes

[25] Paper prepared by Tasman Asia Pacific and Pacific Economic Group for the QCA, 23 January 2001.

proposed by Ergon Energy incorporate these step changes required to move beyond current best practice.

5.6. Conclusions of Possible Cost Reduction

This report has found a number of significant flaws in the data and methods used by TAP and PEG to assess the efficiency of Ergon Energy. These flaws render the quantitative comparisons inaccurate and irrelevant. However, whilst the quantitative comparisons need to the factored downwards, TAP and PEG's conclusions as to what targets are practically achievable are not correct, even if based on 27.7% OPEX reduction, or a more applicable lower percentage.

Indec Consulting's own experience in reducing costs for many Australian organisations directly contradicts TAP and PEG's conclusions. Our experience is that without significant internal or external reform, savings are generally in line with continuous improvement initiatives and sustained savings of greater than 3-5% per annum over ten (10) years is not practically achievable. Furthermore, significant reform cannot be sustained for more than a few years.

The internal reform required to increase the rate of cost savings includes:

- Organisation restructuring.
- Process re-engineering.
- Capital investment.
- Award restructuring.

As detailed in Sections 4 and 6, Ergon Energy has a restructuring plan and the payback of this significant reform is discussed in the next Section. This reform programme will take up to 2-3 years to implement before OPEX savings will be generated.

The conclusions that TAP and PEG draw with respect to cost savings targets, and rates of improvement, in our view, cannot be practically achieved because:

- The quantum of a 27.7% reduction (30% QCA) is not comparing Ergon Energy with similar networks.

- The rate of sustainability of improvements, without taking account of the condition and status of the amalgamated network, is likely to be a lower order than 3% per annum but will be in according with a flattening cost curve and not at an even rate per annum.

- In order to meet long term improvements of a 2-3% magnitude, Ergon 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.

Consequently, our analysis and experience indicates that the TAP and PEG conclusion of a 27.7% reduction in OPEX applied evenly over a ten (10) year period is incorrect in both quantum and timing.

The QCA should consider further the TAP analysis that given all else being equal, and OPEX remained the same, then growth and reliability improvements alone could achieve the proposed efficiency targets within four (4) to six (6) years.

Our analysis suggests that the QCA should not solely focus on reduction, but also the growth and reliability issues be considered particularly as reliability improvements require CAPEX investment and CAPEX is a driver of OPEX.

6. ONE-OFF RESTRUCTURING COSTS AND TIMING

6.1. Restructuring Process

Ergon Energy has identified in its business plan that a number of projects and processes need to be implemented to ensure the restructuring or change management process is successful.

Indec's experience in this and other industries and in these matters indicates that for a change management process to be successful and sustainable, it must be supported by:

- EBA

Sustainable change cannot occur without agreement with the employees.

- Development and Retraining of Employees

The organisations intellectual knowledge is held by its employees. To continue to add value, its employees must be developed.

- Communication Strategy for Stakeholders/Employees

In the instance of Ergon Energy, with the restructuring of six (6) entities, there needs to be significant effort and expenditure focussed on implementing a communication strategy for the duration of the change management process.

- Information Systems

Ergon Energy has identified that there will be substantial information system changes to ensure the efficiency of the management tool.

- Funding

Ergon Energy has identified one-off restructuring costs.

In addition to the above factors, it needs to be strongly noted, that for this change management process to be accepted and successful, it needs to be achieved in a 1-2 year time frame. If this time frame is not met, then the change management team, all stakeholders and employees will become disillusioned and the potential for success will decrease significantly.

It is Indec's experience that for successful restructuring (including outsourcing), there are two (2) key drivers of successful change management.

1. Retraining and development of the employees who remain.

2. Retaining and development of employees who wish to leave.

The costs associated with termination of employment contract arrangements include:

(a) retraining;

(b) salary while retraining;

(c) salary while looking for employment;

(d) early termination; *and*

(e) accrued entitlement.

Without payment of acceptable separation packages, including retraining, restructuring (including labour cost reductions) is unlikely to succeed.

6.2. Restructuring Costs

The asset management as outlined in Section 4 requires the initiation of a single planning framework and one-off restructuring costs in relation to data collection, standardising definitions, design, drawings and work methods, obtaining a skilled team and change management.

The restructuring and retraining costs relate to the phased implementation of the standardisation of the asset management approach, implementation of systems, new work practices, and workplace reform.

The asset planning and changes in work practices are a critical first step. However, although this step change, combined with redundancies, will have a significant impact on OPEX costs, improvements will not be sustainable without appropriate one-off expenditure, that is the revenue cap should be phased in with the savings.

Ergon Energy is an amalgamate of six (6) separate energy companies. Each of these organisations had different cultures and systems. Ergon Energy therefore is not a mature organisation such as the other DNSPs against which it is being benchmarked. In order to be able to "catch up" so as to be as efficient, or at least on the same footing as the other DNSPs the QCA needs to consider the issue of "sunk costs" that is, costs that will not be recoverable over the regulatory time-frame as well as the issue that the proposed reductions in OPEX costs were correct in the Draft Determination.

As part of this effort to "catch up", Ergon Energy has requested a one-off OPEX restructuring costs be part of the revenue cap in the early years of regulation to help Ergon Energy gain the efficiencies of a mature DNSP. In this case, the proposed 30% or 3% per annum target.

The QCA Draft Determination, with regard to one-off restructuring costs, as proposed by Ergon Energy, has stated that: "As with Ergon Energy's restructuring costs, improving service quality and investment in efficiency improvement should provide benefits into the future which more than compensate for the short term financial costs".

The implication of the QCA comment is that the savings will be self-funding.

In other jurisdictions the approach has been that the DNSPs restructured under the previous price structures and that the resultant savings were passed on in the next round of price reviews by benchmarking to best practice.

In this case, if the QCA rejects the restructure costs, then this in effect becomes a "sunk cost". That is, the cost is never recoverable because the associated savings are applied to price reductions now instead of when they occur. Ergon Energy's view is that price re-sets should be in response to cost variations after they occur, whereby the customer should receive the savings in line with the incentive regime.

This comment has to also be considered with regard to the analysis in the previous sections regarding the appropriateness of the 30% OPEX target savings and implication of applying this target at an even rate of 3% per annum over a ten (10) year period. This rate should be considered especially taking account of the fact that the restructuring processes in this and other industries have taken 1-2 years to kick-in and need an initial OPEX investment.

6.3. Restructuring Options

If the restructuring is to be self-funded, as the QCA has proposed savings would need to be triggered by prices (revenue cap) remaining the same together with an initial working capital injection or a loan. The restructuring process would be a phased programme in that each stage could only occur as and when the saving from the previous phase kicked in and these savings would then need to exceed the targeted savings to repay the loan or working capital. That is, the restructure would be on a piecemeal basis that aside from a small funds injection to trigger the first round of savings, further restructure investment would not occur until the first round of savings was realised. Then further investment could occur on a rolling savings realisation basis.

This is not the optimal way to perform restructuring. The restructuring would take time and run the risk that it may not yield the proposed target cost reductions of 3% per annum. The potential savings would be applied to restructuring costs over a longer time frame (with the possibility of the process becoming stalled). That would mean to be self-funding, price (revenue cap) decreases, in relation to OPEX would need to be delayed by a period which is longer than the four (4) year regulatory price period.

Alternatively, if revenue caps are decreased to the targets proposed from the start of year one then Ergon Energy as a corporitised entity, would either have to have a working capital injection or a loan from their owner, namely the government.

A working capital injection would increase the asset base from which a WACC of 8.92% is earnable (together with other Treasury profit requirements) and the working capital return by way of restructure dividend (phased payment) as the savings occur over the entire savings period. This would also require the price (revenue requirement) to be maintained until the savings period is finished.

Alternatively, as other jurisdictions (involving DNSPs against which Ergon Energy is benchmarked) have had an incentive based regime to progress these savings prior to price re-sets, a loan approach would be the preferable alternative method to trigger the restructure.

The loan options are considered further below but essentially Ergon Energy would need to borrow funds in order to initiate the restructuring and ensure its success. Price reduction (or the reduction in the OPEX revenue cap) could not occur until the savings kicked in. The loans in all options would be from Ergon Energy's Shareholder, the Queensland Government. The loan would be repayable in full as the savings from the restructure, are realised. The Government would receive on an annual basis, the published WACC at 8.92% of the funds borrowed. It is essential to note that for this change management process to be effective, it must be carried out in the shortest possible period. For this to be achieved funding must be received.

In order to evaluate the effects of the one-off costs on the nominal operating and maintenance expenditure, a cash-flow model has been developed. This model incorporates the additional one-off costs. The objective of the cash-flow model is to outline the various cost savings attributed to each option and the time frame in which such scenarios will eventually become self-funding operations, the payback period reached and when the restructure would be completed.

The savings are necessary to achieve the projected targets specified by the QCA and are based on 3% per annum. If a lower target is considered more appropriate, the calculation would need to change based on lower one-off costs. In order to be self-funded, it will be necessary to hold the regulated price until the savings have been achieved and reduce the price thereafter in line with savings. The cost model accounts for options in so doing.

Option #1

This is referred to as the "Ergon proposal as submitted to QCA". The restructure process is spread from 2000/2001 to 2003/2004 in accordance with Ergon Energy's proposal. This option indicates that the potential savings are achieved in the last quarter of year five of the process, that is 2005/2006 Qtr 4, with the borrowings and WACC being cleared at the same time.

Option #2

Referred to as the "Accelerated Savings" option as proposed by Indec Consulting. In this option, all restructuring processes are carried out in the first 3 years. Indec Consulting's experiences in restructuring indicate that it is more likely for Ergon Energy to achieve a successful restructure if it is carried out as swiftly as practical. As such, 67% of the process is completed in Year 1, 22% in Year 2 with the remaining 11% completed in Year 3. The potential savings are accounted for in Year 4 and the borrowings are cleared by the end of Year 5 of the process, that is 2005/06 Qtr 3.

Option #3

Referred to as the "Self Funding Option - Minimise Funding or OPEX requirements". This option sees the restructure costs configured to achieve the QCA proposed annual savings in OPEX of 3%. Funding is required for the initial three (3) years with the borrowings totalling $26.8M. Once the borrowings have been repaid, inclusive of the WACC, then the savings are redirected to accelerate the remaining restructure process. In this minimal funding option, the total restructure process is completed at the end of Year 7. The potential savings are achieved in Year 8, with the borrowings being repaid in Year 8, that is 2007/08 Qtr 1.

It is assumed that price re-sets would occur after year five (5) against appropriate benchmarks. Under the self-funding option Ergon Energy and the QCA would then face a similar problem which exists at present in that the savings would not be realised at the time of determination.

The time taken to achieve the restructuring process as indicated previously, is one of the most important factors to consider in order to ensure the process achieves its objectives. The diagram below illustrates the potential timeframe for each of the above options.

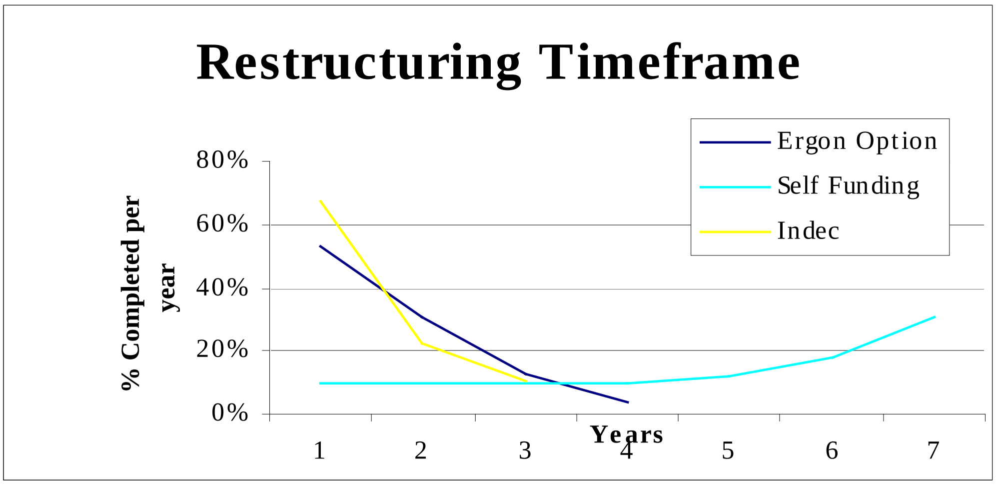


Table 6.3-2: Restructuring Time Frame

With regard to previous section's comments on the appropriateness of QCA's prescribed 30% OPEX targeted savings, spread evenly over ten (10) years, the three options as used above have been reworked with 20% or 2% per annum as the targeted savings value.

The reduction in savings target has the following impact:

Option #1 - "Ergon Energy Option"

The restructure process is completed in year four (4) and the savings should be passed on the customers in year (6).

Option #2 - "Indec Recommended Option"

The restructure process is still completed in the three (3) years with the savings passed onto customers in the sixth (6) year.

Option #3 - "Self-Funding Option"

A total of $29.5M needs to be funded in the first five (5) years of the restructuring process which is completed in the seventh (7) year. The borrowings would be repaid to Government at the beginning of year eight (8) and the savings passed onto customers in the eighth (8) year.

6.4. Restructuring Conclusion

It is Indec Consulting's experience that for a restructure of any magnitude to be successful and accepted it must be completed in the shortest possible timeframe. The major issue facing Ergon Energy is to ascertain where funding will come from to pay for the restructuring costs. The QCA draft determination implies that the savings will be achieved by self-funding. That is, the initial restructure costs which are the catalyst to longer term savings are self-funded.

For self-funding to be triggered, a small loan would be required. The loan in this instance (Option 3) would be for $26.7M which would enable the initial restructuring to commence and the resultant savings would fund the continued restructure process. The major problems with this option are:

- the time to complete the restructure process is excessively long, 7 years, with a possibility of the change management process losing momentum;
- once the restructure is complete and all savings realised in Year 8, only then would the savings be passed onto its customers;
- in the meantime, a price re-set would occur at Year 4.

If the initial savings are passed directly to the customers as price reductions, then the restructure costs would be unrecoverable and become "sunk costs". As a consequence the borrowings would only be paid back as a result of savings from future efficiencies but these will not flow to the stakeholder because of the price re-set at Year 4.

In Option 1, where Ergon Energy's proposed restructure timetable is used, as originally submitted to QCA, the process duration again becomes an issue. It would take three years and three months. In addition, savings wouldn't be passed to the customers until Year 5.

In Option 2, which illustrates Indec Consulting's accelerated savings approach, the restructure would be completed in 3 years, focussing on the favourable point of shortest possible time to ensure the change management process is achievable. Therefore this Option focuses on the key elements of a successful restructure process; completed in the shortest possible timeframe.

In Option 2, the current price structure is maintained for the shortest period. By utilising this option Ergon Energy will be in a position to pass on its new price structure to customers and move towards best practice as desired by the QCA.

In addition to the above workings, the three options have also been calculated at a reduced saving of $20% spread evenly over ten (10) years. This scenario shows a reduction in borrowings required from the Queensland Government.

In summary, the requirement is to achieve the restructuring within four (4) years so that Ergon Energy has attained the savings before the next price re-set otherwise the issue of "sunk costs" remains into the next regulatory period.

The options are as follows:

- The options be self-funded in which case payback would be longer than seven (7) years still requiring the revenue cap to remain at current OPEX level for the whole period and the restructure would run the risk of stalling.

- A working capital injection which would possibly have a longer payback period than four (4) years which would require the current OPEX costs levels to remain as the revenue cap.

- A loan option which would require current OPEX costs to remain as the revenue cap for four (4) years.

- Include the restructure costs in the regulated revenue cap for the four (4) year regulatory period with target savings rates commencing after year two (2).

Clearly, the last option would be more preferable in achieving all stakeholder interests.

The above comments need to be considered in relation to:

- That the 30% savings target as applied at an even rate of 3% per annum is considered inappropriate.

- Growth and reliability factors will also improve efficiency over the four (4) years.

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

7. SUMMARY AND CONCLUSIONS

Our review of the TAP and PEG reports highlighted a number of issues, namely,

- The uniqueness of the Ergon Energy network was not adequately addressed in the reports which raises fundamental issues that prevent the reports from contributing to the price review in a meaningful way.
- That is if Ergon Energy is to close the estimated efficiency gap it would operate a network 75 per cent longer than Powercor for the same level of OPEX expenditure.
- The analysis made by TAP and PEG most likely, do not accurately account for the unique circumstances faced by Ergon Energy.
- The TAP and PEG studies do not "capture the relationship between cost of service and business conditions in the service territory" and business conditions such as density have not been taken into account.
- Inadequate specification of the analytical models, inappropriate date sets and a failure to distinguish between output scale and business conditions have generated estimates of efficiency gains that are fallacious.
- In comparing Ergon Energy with its US peers in terms of the dollar value of OPEX per unit of output, Ergon Energy costs are markedly less.
- The data bases are unsuited to the type and size of Ergon Energy and therefore the conclusions with regard to targets are incorrect.
- The higher measured OPEX cost of Ergon could reflect the business conditions it faces rather than operating efficiency.
- The models do not adjust for business conditions and network type, only for scale.
- The estimation procedure of the PEG study are incorrect in that:
  - There is a collinearity of prediction terms;
  - The model does not include other statistically significant variables;
  - The model in order to predict Ergon Energy is predicting beyond the range of the data.
- The differing cost structures of urban and rural networks has not been factored into the analysis.

- An inappropriate database to estimate the co-efficients in the PEG study has generated estimates and predictions that are of little relevance to the comparative performance assessment of Ergon Energy.
- The analysis performed by PEG should be repeated with values that accurately represent Ergon Energy.
- The QCA do not adequately consider inter-dependencies between service level, capital costs and operating costs. A distribution business' performance will be materially misinterpreted if each factor is assessed in isolation.
- The data and analysis is not fit for the purpose in assessing the overall efficiency of Ergon Energy.
- The conclusions that TAP and PEG draw with respect to cost savings target, and the rate at which Ergon Energy can improve, cannot be practically achieved.
- If Ergon Energy is to achieve the estimated efficiency gap it would operate a network 75% longer than Powercor for the same level of OPEX.

Our analysis of the network costs and network cost drivers reveals that:

- Ergon Energy's relatively higher cost per customer appears to be driven by length of the network required to service its relatively small customer base.
- A cost ratio below industry average may indicate a superior performance or it may reflect the DNSPs customer class and load density.
- Extremely high per customer consumption can lower unit costs and off-set poor customer density.
- OPEX is linked to CAPEX as the greater are the quantity of assets, the greater is the quantity of maintenance.
- There is an accounting variation between states in the treatment of CAPEX giving Queensland DNSPs a higher OPEX by comparison.
- Using output (MWh) alone to assess relative cost can be misleading.
- Customer class and energy density are key cost drivers and Ergon Energy has a lower proportion of high energy users and a low energy density.

- Ergon Energy has a high cost per customer because of the asset base required to service these.

Our review of the condition of the asset and management practices proposed for the amalgamated network revealed that there will be a need over the next 2-3 years to:

- Quantify and improve the maintenance debt involving significant costs.
- Increase CAPEX for renewals and reinforcement of the network to decrease OPEX in the medium term and increase network reliability.
- Develop an overall network strategic plan and supporting sub-plans.
- Clarify the roles and responsibilities of the various parts of the organisation with respect to managing the assets.
- Influence the culture of the organisation towards one of an asset manager and service provision.
- Implement systems to support the above including whole of life costing.
- Change work practices to improve responsiveness and reduce SAIDI minutes per annum across all customer groups.
- Implement changes to the EBA's consistent with the above.
- Review the locations and needs for the number of depots (140 depots) situated throughout Queensland consistent with the above.

The outcome will be that OPEX will remain above benchmark when comparing Ergon Energy's OPEX to a denser network with higher capacity.

Many of the above will require detailed consultation with the shareholding ministers and need to be taken into account when setting regulated OPEX expenditure limits. Some of the requirements of the Regulator may not be consistent with Government policy (regional employment for Queenslanders etc).

Ergon Energy has identified major projects in relation to asset management to develop the skills, information and systems to facilitate long term network optimisation and rationilisation.

Consideration of the applicability of targets ascertained that:

- The TAP and PEG reports did not take account of consideration of the age and condition of the asset base and the relationship between CAPEX and OPEX costs.
- The targets are incorrect in both quantum and timing and to not allow detailed assessment at to:
  - Factors which are outside management control;
  - The ability and time-frame for Ergon to met the proposed targets.
- Reform processes tend to show an initially steep then flattening cost curve, not a straight line cost decline.
- Organisational restructuring will take 1-2 years and asset management will take 3-5 years before savings are realised.
- Ergon Energy will require a phased lead into price reductions if the OPEX savings are to be realised well into the next regulatory period.
- The connection between CAPEX and OPEX is not adequately addressed in the Draft Determination and the CAPEX/OPEX reliability considerations are being addressed in isolation and not together.
- The TAP and PEG conclusion of a 27.7% reduction in OPEX applied evenly over a ten (10) year period is incorrect in both quantum and timing.

One-off restructuring costs and timing analysis shows that:

- The QCA comment that "investment in efficiency improvement should provide benefits into the future which more than compensate for short term financial costs" implies that the investment should be self-funded.
- Aside from the quantum of the efficiency estimate being incorrect, the DNSPs with whom Ergon Energy is being compared have already undertaken the restructuring.
- In other jurisdictions, the DNSPs restructured under previous price structures and the savings were passed on in the next round of price reviews.
- Without payment of the separation package, including retraining, the restructuring may not occur.

- Self-funding of systems, retraining and redundencies will not pay off until well into the next regulatory period and prices will need to remain constant and then decline in line with savings implementation if benefits are to outweigh costs.
- Either a working capital injection or loans are required to ensure the restructure succeeds and the revenue cap would need to reduce in line with savings to ensure the savings were achieved within the regulatory period.
- Reliability at best under the current Draft Determination will remain static without CAPEX infusion.
- An accelerated savings approach would achieve targets within three (3) years and ensure restructure.
- If the restructure costs were not part of the Determination then prices (revenue cap) would need to remain the same for a longer period.
- This aspect and the one-off restructuring costs should be reviewed in relation to growth in GWh and improved reliability increasing efficiency.

Conclusions

The conclusions that TAP and PEG draw with respect to cost savings targets, and rates of improvement, in our view, cannot be practically achieved because:

- The TAP and PEG analysis is not satisfactorily correlated to the Ergon Energy network leading to inappropriate conclusions.
- The TAP and PEG conclusion of a 27.7% reduction in OPEX applied evenly over a ten (10) year period is incorrect in both quantum and timing.
- CAPEX is a key driver of OPEX and investment in CAPEX needs to be undertaken prior to impact on OPEX cost.
- In order to meet long term improvements of a 2-3% magnitude, Ergon Energy needs to undertake a major reform initiative as detailed in the report.
- The reform must occur in the first 1-3 years otherwise impetus will fail.
- 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.
- This reform will take a longer time if the savings are to be self-funded.
- If savings are to be achieved in the regulatory period the one-off restructuring costs need to be included in the Determination.
- The QCA has concentrated soley on reducing OPEX (by the quantum the consultants recommend) but has not considered the aspect of growth and improved reliability improving efficiency whilst the restructuring is undertaken.
- The TAP and PEG studies do not meet the QCA key objectives of:
  - Maintaining the financial integrity of the business;
  - Reducing costs without compromising customer services requirements.

If the QCA base savings at 3% per annum and the restructuring costs are not included in the regulatory revenue then the key objectives of the QCA will not be met.

- The savings percentage and rate need to be reviewed.

APPENDIX A

Cost Driver Analysis Charts and Data

(Attachment)

APPENDIX B

Asset Management

ASSET MANAGEMENT

The Ergon Energy network faces a different operating environment, community risks and customer focus to the distribution businesses with which it is being compared.

The Ergon Energy network is an amalgamation of six (6) small businesses, which covered both geographically and demographically diverse areas. These businesses had to cope with some of the smallest populations per square kilometre that would be found in the world. The organisations could not individually afford a strong network planning and standards group and different work practices and standards developed across the businesses. Strategic decisions were made on smaller asset bases and therefore different management strategies, plans and work practices evolved and because of the EBA's, the employment conditions around these work practices also became established.

In addition, because of cost saving pressures or the need to divert funds into growth (rather than renewals) , each of the businesses developed a maintenance debt which is difficult to quantify.

This quantification difficulty, and indeed inefficient planning, arises from the lack of universal data with common definitions and formats.

The network also supplies to rural and remote customers and obligations imposed by government impact significantly on the performance statistics.

In particular, the re-amalgamated network suffers from non-standardised approaches (as yet) and the data that is necessary to reset the asset management and optimisation process is difficult to retrieve, use and concentrate. Data in the systems is also not current or consistent. As a consequence, Ergon Energy does not have a clear understanding of the performance of the network within its operating environment.

Additionally, Ergon Energy is still developing the techniques and skillsets to manage the network assets and understand the deterioration rates and reliability issues within the various environments in which the assets must perform.

Whilst there is some electronic data and history on assets from the previous six businesses, this data has not been kept in the same formats and therefore asset reliability and degradation is very difficult to determine compared to the Victorian DB's who can produce 5-10 year histories based on 17 years of computerised data (from the previous

SECV) with consistent engineering design, standards and work practices across the State. Ergon now has 3–4 asset management and financial systems, which must be integrated to facilitate 'whole of life costing' and network configuration optimisation.

Ergon Energy has identified major projects in relation to asset management to develop the skills, information and systems to facilitate long term network optimisation and rationalisation.

Ergon Energy understands that there are DB's that have similar assets (not necessarily in the same environment) that have developed suitable processes and systems that Ergon may be able to utilise to accelerate the development of asset management skills and is currently seeking partnerships with these organisations. This aspect is vital in achieving OPEX reductions.

The relationship between OPEX and CAPEX is interlinked and OPEX cost is driven by the CAPEX programme (including renewals). Any reductions to the CAPEX programme increases the maintenance debt leaving Ergon Energy without resources to refurbish assets and further reductions in OPEX will decrease reliability.

The above is compounded by different types of areas within the network, namely coastal strip and industrial compared to rural and remote. These differing areas have different growth rates and cost drivers.

Overall, due to the fragmentation of the network planning and maintenance functions, Ergon does not have sufficient history of the assets in the areas of reliability, efficient renewal costs or accrued maintenance debt to facilitate optimising the relationship between OPEX and CAPEX expenditure and business risk. The QCA therefore needs to take into consideration the asset base and the condition of that base. Comparison of Ergon Energy to other DNSP's without such consideration can lead to revenue reductions which actually limit the quantum and ratio of savings achievable by the network.

Strategy

Over the past ten years, the various regions have operated with fundamentally different asset management strategies, plans and practices. This has resulted in a wide range of asset management directions and related outcomes. In relation to strengthening its core business, and to establish a single planning framework, Ergon Energy is proposing to develop a fully integrated asset management strategy to be implemented over a three year timeframe. The strategy will involve the following:

- Initiate similar standards and definitions across the organisation;
- Developing the skills of the management team;
- A defined network business plan;
- Organisational strategy and change management (six months);
- Defining and implementing savings (business and network);
- Upgrade project resources;
- A contestability programme;
- Business planning and work programming;
- Refining existing planning and scheduling skills;
- Significant upfront investment (larger network asset management team, associated vegetation management plans, systems, etc).

Ergon has identified significant savings through standardisation of asset management approach.

As well as the development of an asset management strategy the following support plans are also required.

- Risk Management Plan;
- Assets Capital Plan;
- Assets Maintenance & Replacement Plan;
- Environmental Management Plan;
- Network Performance Improvement Plan.

Asset Configuration

Network Constraints

Ergon Energy suffers from the "tyranny of distance". The asset base is particularly large and covers a diverse geographic and demographic base. Due to the range of population density covered, the network does not have consistent load requirements. Servicing rural communities tends to mean long assets that are lightly loaded. Ergon Energy has an unusual asset configuration which is dissimilar to other networks ranging from low voltage to 220 KV.

These assets are sparsely spread over a large area and involve high distribution losses especially in SWER lines. The network is a series of long radial feeders and not a close interconnected network which presents both reliability and efficiency issues.

The range of geography covered also leads to wide temperature and weather variations including cyclonic conditions. These aspects also add certain challenges and act to constrain the network.

Demographic changes to the Queensland population and their lifestyle, eg: the greater usage of air-conditioning, is also having an impact on the existing utilisation of the network.

CAPEX

Due to differing capital and operating strategies across the regions some assets in various locations have become rundown over time. This has lead to an increase in OPEX as the asset base becomes less efficient to operate. In general terms there needs to be an increase in the level of asset replacement programs and renewals over the next three years to in turn drive reductions in OPEX.

It is anticipated that savings in OPEX will occur through significant investment but not in the short term. It is anticipated that significant savings may not be realised for up to three years.

Capital Works Prioritisation

Capital works investment prioritisation processes are inconsistent across Ergon and do not adequately take into account risk. All capital project processes including project assessments (costs, benefits and risk) and evaluations (financial and economic) should be standardised and applied consistently across the entire organisation.

Ergon Energy will be required to demonstrate to the Regulator that the CAPEX expenditure is prudent based on its knowledge of:

- The network performance (reliability, utilisation and capacity);
- Risks involved in delays to expenditure;
- Efficient construction and renewal costs; and
- Trade-offs between operating and maintenance expenditure and capital costs.

Whole of Life Costings

To demonstrate the prudency of the CAPEX budget, Ergon Energy will need to undertake 'whole of life' cost analyses on the assets for different operating and renewal strategies by asset type.

This will only be possible once operating, maintenance and reliability data (in the appropriate format) is collected on the assets.

Asset Reliability

Reliability

Ergon Energy considers at present that the network has unacceptable reliability. Supply reliability needs to be improved through developing and implementing various fault improvement programs and initiatives. The quality of supply also needs to be improved through the development of a voltage regulation strategy and the development of a power quality monitoring and improvement strategy.

However, to improve reliability will require a consistent set of definitions and data to track down problems and provide whole of life cost solutions.

For example, there is an inability to identify red or rogue feeders that are the contributors to poor performance. The challenge is the ability to consolidate reliability data to facilitate planning.

Reliability targets will also involve work practice changes. This will require, for instance, reducing the interrupted supply minutes by:

- Better planning;
- Maximising line work;
- Adjusting the capital programme.

Therefore, this will initially require a CAPEX to provide a more reliable and robust asset and one-off OPEX costs.

Risk Management

Effective risk management involves the identification of external risks and then proactively managing them.Whilst some risk assessment has been undertaken in each of the previous businesses, there is currently no clear picture of a risk profile across the assets for Ergon Energy.

In the absence of appropriate risk information, Ergon Energy cannot be sure that the current maintenance cycles are appropriate to address all the service delivery, safety and commercial risks on the assets.

Assessment of asset risks is a necessary pre-requisite to optimising the OPEX and CAPEX mix and determining the level of CAPEX required.

Maintenance and Maintenance Debt

The network reliability needs to be improved while there is an overall reduction in the maintenance budget. There is an estimated maintenance debt on assets of some $7M and a backlog pickup of some $21M. However, there is a difficulty in quantifying this debt and therefore the plan is to:

- Review the assets such as:
  - Inspection of all feeders (5 years);
  - Standards of poles;
  - Low clearance of spans and state of overhead services;
  - High risk areas including vegetation;
  - Low risk – individual services;
- Implement revised practices and maintenance standards;
- Increase inspections of high failure rate assets;
- Identify assets for immediate risk and replacement;
- Establish a programme of audits and risk assessment;

The above approach will involve significant costs for Ergon in the areas of:

- The clearance programme is estimated to cost $60M over three years and needs to be based on an acceptance of the risk magnitude, as the extent of the problem is unknown.
- Ergon has an ongoing problem with significant maintenance expenditure occurring to replace failed overhead services (some 500,000 services have previously been replaced on failure and not monitored). Some $10-20M will be required over the next 5-7 years in CAPEX upgrades of the services (not just for load growth). The problem is mainly in urban areas and is difficult to dimension requiring additional CAPEX.
- A pole replacement program.

<u>Asset Operations</u>

OPEX

The asset condition is generally considered poor across the network. As mentioned previously, Ergon Energy do not have the ability to improve the utilisation of the assets without the expenditure of CAPEX which will have a delayed impact on OPEX.

In particular, this requires additional OPEX for example:

- Optimising transformer locations from lighter load to heavier load locations. Whilst zone sub-stations are in a relatively reliable state, there is a requirement to shift transformers around the network to make sure the load on these is satisfactory.

- The transformers come from a pool which has a history of high utilisation and which are relatively old.

Therefore, there is will be a need to invest in CAPEX over the next 5-15 years.

The outcome will be that OPEX will remain above benchmark when comparing Ergon Energy's OPEX to a denser network with higher capacity.

This aspect in effect is a major difference between Ergon Energy and Energex. The Energex network has remained as the original South East Queensland area and has network data and advanced asset management processes. These include asset optimisation, maintenance planning, vegetation management plans/programs and a whole of life costing approach. Consequently, Energex is in a better position to move to best practice and achieve the OPEX savings proposed.

Energex is a different network and types of initiatives required to move to best practice start from a higher base in relation to the maintenance planning and CAPEX programs and the capability to more fully integrate their asset management functions. Ergon Energy on the other hand will require a phased lead in to price reductions if the OPEX savings are to be realised.

Field Operations

There is a lack of clarity between the roles and responsibilities across the various regions and divisions of Ergon. **The network organisation restructure needs to be completed including the implementation of the Asset Owner/Asset Manager/Service Provider design.** The establishment of the new structure will include the formation and definition of the various functional units.

To increase the asset management skill levels within the organisation there is a requirement for competency development, the development of a learning culture and the establishment of a more rigorous performance management process for all network employees.

The culture of the Network and Service Providers needs to be influenced and reshaped towards one of an asset manager and service provision.

In particular there is a need to build skills and competencies in managing assets as this is currently affecting many areas of performance.

Systems Support

In relation to systems support the systems (MIMS, WASP) are seen as leading edge and basically appropriate. The problems experienced with systems are due to insufficient resources to implement/customise them in a suitable or efficient way to realise all their potential benefits. The data necessary for sound decision making is not readily available from the current systems.

In some instances functionality and data is duplicated across systems, data is not current due to the time lag associated with collection and input and data held in the systems is not perceived as being sufficiently accurate resulting in an ongoing effort being expended verifying and validating data.

Asset management support systems and associated processes need to be established and consistent across the six regions. In relation to asset management processes, this includes the identification of processes, their redesign and standardisation, the identification of a required support system and tools and the implementation of the new processes.

For data collection this involves the identification of data definitions and requirements, the identification of data sources, the development of a data collection program and the actual collection of the data.

There is a lack of consistency in the planning and budgeting data received and placed into the existing system. An attempt is currently being made to standardise policy across the six regions and generate a consistent baseline for planning and budgeting purposes.

The asset management system also contains data that is not current. Inspection rates are to be increased in an attempt to capture current data that can be input into the asset management system.

APPENDIX C

One-Off Restructuring Costs and Timing

This section provided confidentially to QCA