
Appendices

APPENDIX A: ALTERNATIVE MEASURES OF WACC

Classical tax system

As noted by Officer (1994), under a classical tax system, the appropriate definition of a company's pre tax weighted average cost of capital can be expressed as follows:

Cash Flow	WACC
X_0	$r_o = \frac{r_e}{(1-T)} \frac{E}{(E+D)} + r_d \frac{D}{(E+D)}$
	where
	r_e is the return on equity
	r_d is the return on debt (the cost of debt)
	E is the market value of equity
	D is the market value of debt

The amount of tax collected from the company under a classical tax system by the government can be found as $X_g = T(X_0 - X_d)$. Hence,

$$X_0 = T(X_0 - X_d) + X_e + X_d$$

which converts to:

$$X_0(1-T) = X_e + X_d(1-T)$$

The after tax weighted average cost of capital under a classical tax system can be expressed as either:

Cash Flow	WACC
$X_0(1-T)$	$r_1^c = r_e \frac{E}{(E+D)} + r_d (1-T) \frac{D}{(E+D)}$
$X_0 - (X_0 - X_d)T_c$	$r_2^c = r_e \frac{E}{(E+D)} + r_d \frac{D}{(E+D)}$

Dividend imputation system

Under the dividend imputation tax system shareholders recover, via imputation tax credits, some proportion of the corporate taxes that have already been paid. This has two effects relevant to the calculation of WACC. First, it decreases the effective corporate tax rate and thereby increases the cash flows to shareholders. Second, the decrease in the effective tax rate will reduce the effective tax shield provided by debt relative to equity. Therefore, under dividend imputation, it is necessary to allow for increased cash flow to shareholders and the increased after tax cost of debt.

In the presence of dividend imputation, the effective tax rate changes from T_c to $T_e = T_c(1-\gamma)$ where:

- T_c is the statutory tax rate (equivalent to the classical tax rate); and
- γ is the value of imputation credits and represents the proportion of tax collected from the company which gives rise to the tax credit associated with a franked dividend.

In the presence of dividend imputation, the appropriate definition of a company's pre tax weighted average cost of capital can be expressed as:

Cash Flow	WACC
X_0	$r_o = \frac{r_e}{(1-T_c(1-g))} \frac{E}{(E+D)} + r_d \frac{D}{(E+D)}$

Under dividend imputation, the effective level of company tax is defined as:

$$\begin{aligned} X_g &= T(X_0 - X_d) - gT(X_0 - X_d) \\ &= T(X_0 - X_d)(1-g) \end{aligned}$$

Hence:

$$X_0 = (X_0 - X_d)T_c(1-g) + X_e + X_d$$

which converts to:

$$X_0(1-T_c(1-g)) = X_e + X_d(1-T_c(1-g))$$

In the presence of dividend imputation, the appropriate definition of a company's post tax weighted average cost of capital can be expressed as:

Cash Flow	WACC
$X_0 (1 - T_c)$	$WACC\ 1 = r_e \frac{(1 - T_c) E}{(1 - T_c (1 - g)) (E + D)} + r_d (1 - T_c) \frac{D}{(E + D)}$
$X_0 (1 - T_c (1 - g))$	$WACC\ 2 = r_e \frac{E}{(E + D)} + r_d (1 - T_c (1 - g)) \frac{D}{(E + D)}$
$X_0 - (X_0 - X_d) T_c (1 - g)$	$WACC\ 3 = r_e \frac{E}{(E + D)} + r_d \frac{D}{(E + D)}$
$X_0 (1 - T_c) + g T_c (X_0 - X_d)$	$WACC\ 4 = r_e \frac{E}{(E + D)} + r_d (1 - T_c) \frac{D}{(E + D)}$

APPENDIX B: THE RELATIONSHIP BETWEEN EQUITY, DEBT AND ASSET BETAS

The WACC relationship expresses the entity's cost of capital as the weighted average of the required return on its equity and debt. Because of the equivalence between the assets of the entity to a portfolio of the entity's equity and debt with respective weights of $\frac{E}{E+D}$ for equity and $\frac{D}{E+D}$ for debt, the return on assets can be expressed as follows:

$$R_a = R_e \left(\frac{E}{E+D} \right) + R_d \left(\frac{D}{E+D} \right)$$

Substituting CAPM for each of the returns (R_f , R_e and R_d) gives:

$$R_f + \mathbf{b}_a (R_m - R_f) = \left(R_f + \mathbf{b}_e (R_m - R_f) \right) \left(\frac{E}{D+E} \right) + \left(R_f + \mathbf{b}_d (R_m - R_f) \right) \left(\frac{D}{D+E} \right)$$

which is equivalent to:

$$\mathbf{b}_a = \mathbf{b}_e \left(\frac{E}{D+E} \right) + \mathbf{b}_d \left(\frac{D}{D+E} \right)$$

An asset beta represents the risk arising from the sensitivity, or covariance, of the operating cash flows generated by the assets of an entity compared with the market in general. Asset betas are not directly observable and therefore must be derived directly from equity betas. The difference between an asset beta and an equity beta reflects the extent to which debt is used to finance the entity's assets.

It is obvious from above that the beta of an entity's assets is equal to the betas of the entity's equity and debt weighted by the respective weights for equity and debt. Whilst equity and debt betas can be calculated via CAPM based methods, the asset beta can only be inferred via the above relationship.

Issues in the estimation of the equity beta

An entity's equity beta (β_e) reflects both the market risk associated with its assets and the financial risk born by shareholders due to the entity's use of debt financing. CAPM assumes that a linear relationship exists between an entity's gearing and the premium associated with that gearing. Two factors have been identified as key determinants of an entity's equity beta:

- financial leverage – the ratio of debt to equity, where a higher level of debt implies a higher beta; and
- sensitivity to cash flows – relative to overall economic activity, where more cyclical cash flows are associated with higher betas.

Typically, equity betas are estimated using historical data through the application of the market model which is derived from CAPM (expanded as follows):

$$R_i = R_f + b_i R_m + b_i R_f$$

$$R_i = R_f (1 - b_i) + b_i R_m$$

$$R_i = a_i + b_i R_m$$

where

a_i is equal to $R_f (1 - b_i)$

b_i is the equity beta

The estimation of equity betas is not without controversy. There are numerous issues relevant to its estimation that the Authority considered, including the following:

- the choice of return measure – for example whether returns should be discrete or continuously compounded, whether raw or excess returns should be used and whether nominal or real returns should be used. Typically the risk free rate and market risk premium are both expressed as discretely compounded returns;
- the choice of proxy for the market portfolio. By definition, the measurement of a beta is relative to a market risk premium, which in turn relates to a single specific market. Accordingly, beta estimates for a company differ depending on which stock market index is used – systematic risk is largely country specific and meaningful beta estimates can only be derived using a national index from a company’s own country of operation. Therefore caution is required in comparing betas of companies operating in similar industries but in different countries as betas reflect the risk of a company relative to the market in which it operates. Differences in market composition of national share markets do not facilitate direct comparison of betas. As outlined in Table B1, the Australian stock market has a greater component of resource stocks, which account for 16.5 per cent of total Australian market capitalisation. This suggests that the ASX may have a different risk profile compared with the US stock market (where resources stock account for 6.9 per cent of total US stock market capitalisation, and 7.4 per cent of total UK stock market capitalisation). The increased diversification of the Australian market relative to the US and UK markets would suggest that betas for comparable companies in the US and UK will be higher than in Australia;

Table B1: Composition of Market Indices

Index (as at 30 Nov 1998)	Resource Sector	Industrial Sector	Market Capitalisation
Australian All Ordinaries Accumulation Index	16.5%	83.5%	A\$417.0 billion
US Standard & Poors 500	6.9%	93.1%	US\$10.6 trillion
UK FTSE 100	7.4%	92.6%	£1.04 trillion

- the sampling interval for the data and the length of the estimation period. Estimates using short interval data (measured at daily or weekly intervals) are systematically biased, such that highly traded securities are over stated whilst those of infrequently traded securities are understated. Alternatively, use of long intervals (measured quarterly or annually), lowers the number of data points used in the estimation process and diminishes the accuracy of beta measures. Empirical evidence discussed in Brailsford, Faff and Oliver (1997) shows that beta estimates using monthly data estimated over 4 to 5 year intervals provide the most

reasonable trade off between the number of observations and the stability of beta estimates;
and

- beta is typically estimated using the market model, using an ordinary least squares approach. As with all econometric modelling applications there are a number of assumptions which need to be satisfied in order to produce a robust estimate.

The Authority regards the stability of beta as an important issue in identifying the appropriate equity beta for electricity distribution businesses. Empirical evidence from Australian markets strongly supports the mean reversion of beta. Raw beta values, derived from historical data, can be adjusted based on the assumption that beta factors change over time especially in industries where there is considerable structural reform underway.¹ The true beta has a tendency over time to move toward the market average of one and this adjustment may be represented as:

$$\text{Adjusted (future) beta} = \text{Raw Beta} * (0.67) + 0.33$$

This is the approach adopted by Bloomberg (2000), which appears to be more generally accepted by practitioners.

The Authority is still reviewing the use of an adjustment factor for beta. However, for the purpose of the Draft Determination the Authority has applied the Bloomberg adjustment factor as follows when estimating betas:

$$\text{Adjusted beta} = 0.33 + 0.67b_i$$

Issues in the estimation of debt betas

The debt beta (β_d) reflects the financial risk born by shareholders due to the entity's use of debt financing. The CAPM can be used to identify the debt beta.

$$R_d = R_f + b_d [R_m - R_f]$$

Transformed

$$b_d = \frac{(R_d - R_f)}{[R_m - R_f]}$$

where

R_f = the risk free rate

R_m = the expected return on the market portfolio of risky assets

R_d = the expected return on debt

$$b_d = \frac{Cov(R_d, R_m)}{Var(R_m)} = \text{the debt beta}$$

$[R_m - R_f]$ = the equity risk premium

The debt beta calculation is very sensitive to the size of the market risk premium. If the market risk premium increases this will have the impact of reducing the size of the debt beta.

Some regulators apply the CAPM based model with a 50 basis point adjustment to reflect the administrative costs of establishing and maintaining a debt financing facility. The resulting adjusted debt beta will be lower than the unadjusted debt beta. However, equity capital also incurs

¹ International studies supporting the use of adjusted betas include Sharpe, Alexander and Bailey (1995) and Blume (1975).

administrative and other costs and fees. To adjust the cost of only one form of capital (debt or equity) would distort the relative costs. Since there are administrative costs associated with both forms of capital, the Authority does not support an adjustment to the cost of debt or equity for fees which are operating expenses to the business.

Issues in the estimation of asset betas

The CAPM assumes a linear relationship between the equity beta and the gearing of an entity. Hence, it is possible to calculate asset betas from equity betas. The asset beta refers to the beta applicable to the assets of an entity that has no debt. The gearing of the entity needs to be taken into account in estimating asset betas because default risk is incorporated in equity values and this needs to be removed to arrive at the entity's risk profile independent of its financial structure. The adjustment of estimated equity betas to remove the financial risk associated with a security, leaving the risk of the asset encapsulated in the asset beta (β_a) is known as delevering of the equity beta.

There are several approaches to delevering and relevering betas and there is no consensus about which is the most appropriate method. The QCA identified the following methods extensively used by academics and regulators to delever and relever equity betas. They have been broadly categorised by the QCA as:

- the standard or textbook approaches including both the Brealey Myers (1999) and Conine (1980) approaches;
- the Davis (1998) approach; and
- the Appleyard & Strong (1998) / Monkhouse approach.

The Authority undertook an analysis of the alternative approaches and found the resulting impact on WACC of using the alternative approaches was not significant. This view was also supported by the ORG (2000a) which noted:

“The impact on the estimated after-tax WACC of using a different debt beta and levering approaches [is] not significant, however, *provided* that the same approach is used when deriving a proxy asset beta from the comparable entities, as is used when deriving a proxy asset beta back into an equity beta.”

Based on its analysis of the alternative approaches and consistent with its use of the post tax nominal WACC, the Authority has used the Brealey/Myers approach in all delevering/relevering applications.

APPENDIX C: ESTIMATION OF AN EQUITY BETA FOR ELECTRICITY DISTRIBUTION BUSINESSES

Identification of comparable data

Australian electricity distribution data

To identify asset betas for electricity distribution firms from Australian data, the Authority had regard to the following comparable firms and regulatory decisions:

- gas and electricity utilities; and
- regulatory decisions involving electricity and gas distributors.

None of the publicly listed electricity distribution businesses in Australia have been operating for five or more years. As at November 2000 there were 12 publicly listed utility firms which specified electricity or gas as their primary area of business. Of these firms, four were listed in the last 2 years which precludes them from the data sample.² Of the remaining eight, Renewable Energy Corporation Limited was precluded as its primary operations involved the generation of gas from biomass waste, and Envirostar Energy Limited was precluded as its primary gas operations involved coal gasification in China. Of the remaining six firms, three are engaged in electricity generation, two in gas distribution and retailing and one in the business of electricity distribution. The sample was supplemented with the gas electricity distribution and retailing firm Allgas Energy Limited which ceased trading in July 1999.

Table C.1 reports the equity and asset betas Australian electricity and gas listed firms. Australian ASX listed asset betas delevered from adjusted equity betas are in the broad range of 0.12 to 1.87. The electricity generators are in the range of 0.87 to 1.87, the gas distributors between 0.12 and 0.58 and United Energy has an estimated asset beta of 0.45. If gas and electricity distributors are considered in isolation from the electricity generators, all are below an asset beta of 0.60 with three below 0.50.

Analysis of all activities reported in Annual reports for each of the listed electricity and gas utility companies in Table C.1 highlights that none of the companies is a “pure play” electricity distribution company. Energy Developments Limited, Pacific Energy Limited and Pacific Hydro Limited are all involved in the capital intensive industry of electricity generation. Envestra Ltd, Allgas Energy Limited and Australian Gas Light Ltd are involved in gas distribution. However, Australian Gas Light Ltd also has substantial interests in the distribution of electricity. The only listed electricity distribution firm, United Energy Ltd, also has interests in the distribution of gas. As none of the listed firms are exclusively in the business of electricity distribution, the asset betas for the firms listed in Table C.1 exceed the asset betas for regulated electricity distribution businesses.³

² Advanced Energy Systems Limited (listed 13/10/00), Alintagas Limited (listed 17/10/00), Contact Energy Limited (listed 11/05/99) and Horizon Energy Investment Group (28/01/00).

³ This view is supported in ORG (2000).

Table C.1: Electricity and Gas Equity and Asset Betas - Australian Listed Companies

Firm	Primary Business	Equity Beta ⁴	Leverage ⁵ (%)	Asset Beta ⁶
Allgas Energy Limited ⁷	Gas distribution and retailing	0.50	0.1700	0.48
Australian Gas Light Ltd	Gas distribution and retailing	0.73	0.3084	0.58
Envestra Ltd ⁸	Gas distribution and retailing	0.46	0.7978	0.12
Energy Developments Limited	Electricity generation	1.23	0.2903	0.87
Pacific Energy Limited	Electricity generation	2.13	0.1768	1.87
Pacific Hydro Limited	Electricity generation	1.03	0.3348	0.97
United Energy Ltd ⁹	Electricity distribution	0.85	0.5148	0.45

Firms involved in the provision of utility services usually engage in long term projects and have high stability in their income and returns but also have a high ratio of fixed costs. Further, the product supplied by such firms is generally regarded as being of an essential nature and demand variations tend to be small but nevertheless highly linked to changes in the general level of economic activity.

In Australia, there have been several recent new listings of infrastructure and utilities companies and regulators such as IPART, the ORG and the ACCC have all made decisions with respect to access arrangements in the gas and electricity distribution industries. Table C.2 reports the equity and asset betas from recent Australian regulatory decisions involving gas and electricity distributors. Reported asset betas delevered from adjusted equity betas for electricity distribution decisions are in the broad range of 0.35 to 0.50.

Table C.2: Asset and Equity Beta Factors

Entity/Author	Industry	Asset Beta Factor	Equity Beta Factor
ORG (2000)	Electricity distribution	0.40	1.00
IPART (1999c)	Electricity distribution	0.35-0.50	0.77-1.14
IPART (1999d)	Electricity distribution	0.35-0.50	0.78-1.14
OTTER (1999)	Electricity distribution	-	0.95
DME (1999)	Electricity	-	0.8
ORG (1998b)	Gas distribution	0.55	1.2
IPART (1999b)	Gas distribution	0.40-0.50	0.96-1.10

⁴ Bloomberg (2000). These beta estimates are based on 60 monthly observations over the period 31 August 1995 to 31 August 2000. Equity betas are adjusted equity beta estimated using the Bloomberg adjustment:
Adjusted beta = raw beta * 0.67+0.33

⁵ For the purpose of estimation, leverage is measured as the three year average of Book value of total borrowings / (Book value of total borrowings + market capitalisation).

⁶ The Authority used the following active debt management approach to delever and relever equity betas and assumed a debt beta of 0.20. Gearing used in the delevering of equity betas was estimated as the book value of debt divided by the book value of debt plus the market value of equity (market capitalisation).

$$b_a = \frac{b_e + b_d \times \frac{D}{E}}{1 + \frac{D}{E}} \quad \text{and} \quad b_e = b_a + (b_a - b_d) \times \frac{D}{E}$$

⁷ The equity beta of Allgas Energy Ltd was calculated with 60 monthly observations measured from 31 August 1993 to 31 August 1998.

⁸ The equity beta of Envestra Ltd was calculated with only 36 monthly observations.

⁹ The equity beta of United Energy Ltd was calculated with only 27 observations.

Overseas electricity distributors

As there are no listed Australian distribution companies, overseas electricity companies were also considered by the Authority. However, it is noted that international betas are not directly comparable to Australian betas and extreme care must be taken in their interpretation. The following significant differences exist between US and UK integrated electricity companies and electricity distribution companies operating in Queensland:

- different stock markets and macroeconomic conditions. As discussed in Appendix B, differences in market composition of national share markets do not facilitate direct comparison of betas;
- differing regulatory regimes. The electricity industry is characterised internationally by privately owned vertically integrated organisations. Generally rates and service terms are established by commercial contracts. Electricity distribution activities are subject to either rate of return, price cap or revenue cap regulation;
- variations in industry structure and levels of competition - the Australian and Queensland transportation market is a substantially smaller industry to that in the US and UK. From Tables C.3 and C.4 it can be seen that more than 90 percent of the entities have asset values in excess of \$3 billion Australian dollars which is substantially higher than Australian electricity and gas distribution listed companies;¹⁰ and
- variations in the scope of non-distribution activities within entities - the US integrated companies in particular tend to be diversified organisations with a range of different businesses across the generation, transmission, distribution and retailing of electricity and in some cases gas and other activities. In contrast, the electricity distributors are assumed for regulatory purposes to not engage in business activities other than the distribution of electricity, regardless of the fact that their actual corporate structure which involves distribution and retailing of electricity in the case of Ergon Energy and the distribution and retailing of electricity and gas by Energex.

Table C.3 details the asset size, equity beta, gearing and asset beta for a range of UK integrated electricity firms. The asset betas estimated from adjusted equity betas range from 0.41 to 0.72 with three of the four companies having an asset beta below 0.55. This range is narrower than the range of 0.22 to 0.78 observed for US integrated firms as shown in Table C.4. However, of the US listed companies, only one had an asset beta above 0.55 with the most being less than 0.35.

¹⁰ For example, AGL has total assets of \$3,616 million (June 1999), Envestra has total assets of \$2,287.76 million (June 2000) and United Energy has total assets of \$1,928 million (December 1999).

Table C.3: UK Integrated Electricity Listed Companies

Firm	Total Assets¹¹ (\$A)	Equity Beta¹²	Leverage¹³ (%)	Asset Beta¹⁴
British Energy PLC	17,859.7	1.00	31.29	0.72
Scottish & Southern Energy PLC	10,641.6	0.60	19.49	0.52
Scottish Power PLC	60,569.9	0.64	45.01	0.44
Viridian Group PLC	2,528.6	0.48	25.92	0.41

Table C.4: US Integrated Electricity Listed Companies

Firm	Total Assets¹⁵ (\$Am)	Equity Beta¹⁶	Leverage¹⁷ (%)	Asset Beta¹⁸
Avista Corp	37,383.4	0.34	48.74	0.27
American Electric Power	6,460.5	0.62	46.97	0.41
Black Hills Corp	1,174.0	0.45	30.00	0.37
Bangor Hydro-Electric Co	946.4	0.81	75.22	0.40
CP & L Energy Inc	16,517.0	0.47	34.95	0.37
Central Vermont Public Service Corporation	981.2	0.75	57.93	0.43
Cinergy Corp	16,730.9	0.30	43.93	0.26
Cleco Corp	2,965.7	0.40	41.23	0.32
CMS Energy Corp	26,899.8	0.60	63.62	0.34
Consolidated Edison Inc	27,020.7	0.45	37.13	0.35
Constellation Energy Group	16,847.3	0.52	43.48	0.38
Dominion Resources Inc	30,875.1	0.44	45.55	0.33
DPL Inc	7,551.1	0.40	31.67	0.34
DQE Inc	9,758.2	0.47	42.65	0.35
DTE Energy Company	21,426.6	0.36	48.15	0.28

¹¹ Calculated using UK pound exchange rate of 0.3948 at 31 August 2000.

¹² Bloomberg (2000). These beta estimates are based on 60 monthly observations over the period 31 August 1995 to 31 August 2000. Equity betas are adjusted equity beta estimated using the Bloomberg adjustment:
Adjusted beta = raw beta * 0.67+0.33

¹³ For purpose of estimation leverage is measured as the three year average of Book value of total borrowings / (Book value of total borrowings + market capitalisation).

¹⁴ The Authority used the following active debt management approach to delever and relever equity betas and assumed a debt beta of 0.20. Gearing used in the delevering of equity betas was estimated as the book value of debt divided by the book value of debt plus the market value of equity (market capitalisation).

$$b_a = \frac{b_e + b_d \times \frac{D}{E}}{1 + \frac{D}{E}} \quad \text{and} \quad b_e = b_a + (b_a - b_d) \times \frac{D}{E}$$

¹⁵ Calculated using US dollar exchange rate of 0.5748 at 31 August 2000.

¹⁶ Bloomberg (2000). These beta estimates are based on 60 monthly observations over the period 31 August 1995 to 31 August 2000. Equity betas are adjusted equity beta estimated using the Bloomberg adjustment:
Adjusted beta = raw beta * 0.67+0.33

¹⁷ For the purpose of estimation, leverage is measured as the three year average of Book value of total borrowings / (Book value of total borrowings + market capitalisation).

¹⁸ The Authority used the following active debt management approach to delever and relever equity betas and assumed a debt beta of 0.20. Gearing used in the delevering of equity betas was estimated as the book value of debt divided by the book value of debt plus the market value of equity (market capitalisation).

$$b_a = \frac{b_e + b_d \times \frac{D}{E}}{1 + \frac{D}{E}} \quad \text{and} \quad b_e = b_a + (b_a - b_d) \times \frac{D}{E}$$

Firm	Total Assets (\$Am)	Equity Beta	Leverage (%)	Asset Beta
Duke Energy Corp	58,122.8	0.37	35.17	0.31
Edison International	63,028.9	0.26	61.79	0.22
El Paso Electric Company	2,828.6	0.73	59.31	0.41
Empire District Electric Company	1,272.4	0.28	42.73	0.25
Entergy Corp	29,988.0	0.46	51.24	0.33
FirstEnergy Corp	31,704.9	0.40	54.19	0.29
Florida Progress Corp	11,357.3	0.32	35.81	0.28
Florida Public Utilities Company	168.4	0.44	41.98	0.34
GPU Inc	37,783.8	0.62	60.97	0.35
Green Mountain Power Corp	521.6	0.26	69.40	0.22
Hawaiian Electric Industries Inc	14,424.1	0.42	66.88	0.27
Kansas City Power & Light Company	5,202.0	0.58	41.91	0.42
LG & E Energy Corp	8,931.5	0.31	41.03	0.26
Madison Gas & Electric Company	862.0	0.36	33.52	0.31
Maine Public service Company	298.4	0.38	62.50	0.27
MDU Resources Group Inc	3,072.9	0.29	28.35	0.26
Montanna Power Company	5,303.9	0.90	17.13	0.78
Niagara Mohawk Holdings Inc	22,043.2	0.62	70.13	0.32
Nisource inc	11,891.4	0.51	47.42	0.36
OGE Energy Corp	6,822.0	0.39	45.31	0.30
Peco Energy Company	22,824.5	0.32	40.96	0.27
PG & E Corp	51,696.2	0.40	47.60	0.30
PPL Corp	19,439.8	0.52	53.99	0.35
Public Service Company of New Mexico	4,737.8	0.58	56.20	0.37
Public Service Enterprise Group Inc	33,081.1	0.46	46.84	0.34
Puget Sound Energy Inc	8,952.0	0.42	53.66	0.30
Reliant Energy Inc	45,617.4	0.46	55.69	0.31
RGS Energy Group Inc	4,284.8	0.60	48.34	0.40
Scana Corp	10,457.6	0.39	40.86	0.31
Southern Company	66,798.9	0.36	45.69	0.29
Teco Energy Inc	8,159.5	0.43	40.01	0.34
Unicom Corp	40,720.3	0.34	53.15	0.27
Unitil Corp	632.4	0.72	55.02	0.43
Western Resources Inc	13,932.2	0.50	70.29	0.29
Wisconsin Energy Corp	10,843.9	0.43	47.63	0.32
WPS Resources Corp	3,160.2	0.36	44.84	0.29

New York University publishes industry summary equity and asset betas for US Utilities. Figures from 1998 are reported in Table C.4 for a range of US utilities. The reported results for US electricity firms are similar to those reported in Table C.3.

Table C.5: US Infrastructure and Utility Equity and Asset Betas¹⁹

	Equity Beta (b _e)	Asset Beta (b _a)
Electric utility (central)	0.53	0.27
Electric utility (east)	0.54	0.23
Electric utility (west)	0.56	0.31
Natural gas (distribution)	0.59	0.34
Natural gas (diversified)	0.82	0.34
Water utility	0.55	0.31

Note: International betas are not directly comparable to Australian betas and extreme care must be taken in their interpretation.

Analysis of electricity distributors cash flows

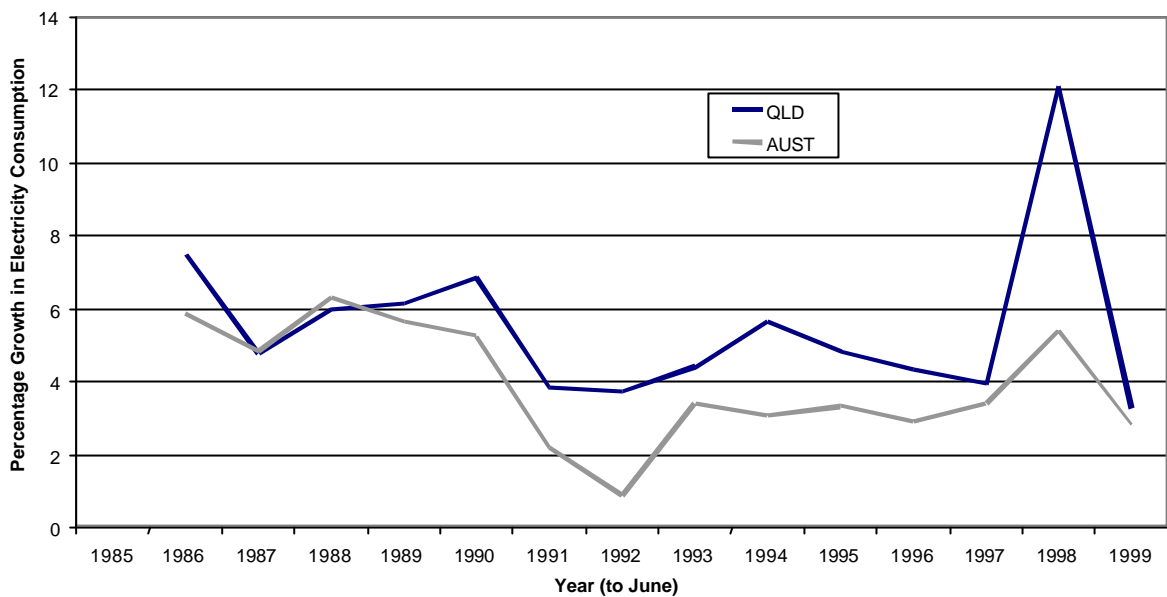
The exposure of electricity distribution businesses cash flows was analysed by the QCA with respect to factors likely to affect the demand and supply of distributed electricity. The QCA found that electricity distributors were exposed to:

- variability in the consumption and distribution of electricity. Figure C.1 displays the growth in consumption of electricity measured in millions of kilowatt-hours during the period from 1985 to 1999 in Queensland and Australia.²⁰ Since 1985 total electricity consumption has grown by greater than 100 percent in Queensland and almost 72 percent growth for Australia. The annual growth rate in Queensland has averaged 5.53 percent whilst the Australian average is only 3.96%. If the substantial upward growth spike in Queensland in 1998 is excluded the Queensland average growth rate is 5.03% whilst the national growth rate is only 3.85%. Over the total period, the variability of this growth in consumption is higher in Queensland than at the national level;²¹

¹⁹ Damodaran, A. (1998) Stern School of Business, New York University – Betas and unlevered betas by industry at 31 December 1998.

²⁰ Consumption is used as a proxy for the level of distribution of electricity.

²¹ The standard deviation of the growth in electricity consumption in Queensland is 2.27 and at the national level 1.60. If data from 1998 is excluded these figures become 1.30 and 1.60 respectively suggesting that Queensland typically has similar variability to the national level of consumption.

Figure C.1: Queensland and Australian Consumption of Electricity

- sensitivity to prevailing economic conditions – the industry is highly integrated to the domestic economy and faces exposure to domestic macroeconomic risks. For example, the growth in electricity consumption is positively correlated to growth in GDP. Australian electricity consumption growth has a correlation of 32 percent with growth in GDP. This result is not unexpected as electricity consumption involves both domestic and industrial consumption of electricity. In Queensland, the correlation is 15 per cent;
- electricity DNSP's have only limited exposure to foreign exchange and interest variability. Exposure to nominal interest rate variability is further decreased through the use of the CPI-X mechanism which compensates for changes in the level of inflation; and
- minimal exposure to technological change. Changes to the technology used in electricity distribution have been slow and incremental. Basic techniques in electricity distribution have been largely unchanged for many years. Hence, there appears to be little risk of obsolescence or the need for technology substitution due to advances in technology.²²

Conclusions regarding the electricity distributors asset and equity beta

For entities with no traded equity, such as the electricity distribution businesses, it is necessary to use judgement in determining the appropriate asset and equity beta to be used in the estimation of the required return on equity funds.²³

To calculate an equity beta for electricity distribution businesses requires:

- the review of asset betas of comparable businesses;
- analysis of factors affecting the stability of electricity DNSP's cash flows to assist in positioning the asset beta within a selected asset beta range; and
- the selection of an appropriate debt to equity ratio.

²² The risk of technological obsolescence is more likely to be characterised as diversifiable risk.

²³ The associated increase in subjectivity which results does not lessen the fact that the cost of equity capital should still reflect the rate of return required by a shareholder.

Comparable asset betas were estimated from adjusted equity betas reported for Australian and international firms involved in electricity distribution. From the Australian market, listed firms and regulatory bodies suggest asset betas of:

Industry	Asset Beta Range (based on adjusted equity betas)
Electricity generation (listed companies)	0.87 – 0.97 ²⁴
Electricity and Gas distribution (listed companies)	0.45 – 0.58 ²⁵
Electricity distribution (regulatory decisions)	0.35 – 0.50
Gas distribution (regulatory decisions)	0.40 – 0.55

Although not directly comparable to Australian asset betas, it is noted that international asset betas are available for integrated electricity and for utilities and are summarised as follows:

Industry	Asset Beta Range
Electricity (US)	0.22 – 0.78
Electricity (UK)	0.41 – 0.72
Utilities (US)	0.23 – 0.34

The Authority considers the asset betas of the electricity generators are likely to be significantly higher than those of distribution businesses. Due to their diversified interests, the asset betas of listed electricity and gas distribution companies provides a more reasonable range for asset betas between 0.45 and 0.58. However, as noted earlier, these asset betas are overstated. Further, recent regulatory decisions have placed electricity asset betas in the range of 0.35 to 0.50. If considered independently of the cash flows, a reasonable range for asset betas calculated with adjusted equity betas would be between 0.40 and 0.55. This suggests an adjusted equity beta in the range of 0.60 to 0.97.²⁶

²⁴ The actual range for listed Australian electricity generators is 0.87 to 1.87. However, the asset beta of Pacific Energy Limited at 1.87 represents an extreme outlier and it was excluded.

²⁵ The actual range for Australian gas distributors is 0.12 to 0.58. However, for Envestra (asset beta of 0.12) the equity beta was estimated using only 36 observations, and the company had a leverage ratio of 0.7978. This makes Envestra's asset beta an atypical outlier relative to other electricity and gas distributors which have a range of 0.1700 to 0.5148 and it was therefore excluded.

²⁶ Calculations were performed assuming a debt to equity ratio of 1.50 (Debt = 0.60, Equity = 0.40) and a debt beta of 0.27. The actual calculated adjusted equity beta range is 0.72 to 0.97. Caution must be exercised in the calculation of equity betas across a range of asset betas. As documented in F. Marston & S. Perry, (1996) 'Implied penalty for financial leverage: theory versus empirical evidence', *Quarterly Journal of Business and Economics*, Vol 35, No 2, pp77-97, the relationship between equity betas and financial leverage is non-linear with

The QCA has also considered Energex's submission of an asset beta in the range of 0.5 to 0.6 and Ergon Energy's submission of 0.55 for electricity distribution businesses. Other stakeholder's submissions were also considered. However, when comparable listed firms and regulatory decisions are jointly considered with the electricity distribution businesses cash flow characteristics, the QCA considers that an asset beta of 0.55 or higher would overstate the asset beta of electricity distribution firms. The Authority has estimated the asset beta²⁷ to fall between a range of 0.40 to 0.55 and has set the asset beta at 0.50.

Based on the asset betas of comparable Australian listed companies, other regulatory decisions and analysis of factors effecting the variability of cash flows, the Authority has arrived at an adjusted equity beta for Queensland DNSPs of 0.85.

a higher penalty in the calculation of asset betas for those firms with high levels of leverage relative to firms with low leverage.

²⁷ Based on adjusted equity betas.

APPENDIX D: ELECTRICITY DISTRIBUTION: REGULATORY ACCOUNTING AND INFORMATION GUIDELINES

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GLOSSARY

Accounts mean a system of financial records and recording that enable revenue earned and costs incurred in meeting the obligations incurred under a **Distribution Licence** to be separately identified from any other business the **Licensee** or its **Related Parties** might be carrying on.

Account Heading means either an account heading used in an accounting record such as a general ledger or a higher level summarisation of such headings.

Audit Report means either a **Regulatory Audit Report** or a **Report to the Authority and the Licensee**.

Auditor means an independent registered company Auditor.

Authority means the Queensland Competition Authority.

Causal or Causation, Basis or Relationship means, in relation to a basis of allocation, that the allocation base is the most significant trigger of consumption or utilisation of the resources or services represented by the costs or other account item that is being allocated.

Capital Expenditure means any expenditure, which for the purpose of **Statutory Accounts**, has been included in the Fixed Asset Base of the **DNSP**.

Code means the National Electricity Code.

Directly Attributable or Directly Attributed. An item is **Directly Attributable** or **Directly Attributed** to an object such as the **DNSP**, if it is wholly and exclusively associated with that object.

Director means a director of a **Licensee**. Where a **Licensee** is not a corporation that appoints directors, **Director** shall refer to senior managers of the **Licensee**, whose identities shall be confirmed by the **Licensee** with **the Authority**, prior to the delivery of information required by this Guideline.

Directors' Responsibility Statement means a statement signed and dated by a **Director** of a **Licensee** which states whether in the **Directors'** opinion, the **Regulatory Accounting Statements**:

- present fairly the profit and loss account information required by this Guideline;
- present fairly the balance sheet information required by this Guideline;
- have been made out in accordance with applicable and appropriate accounting principles and policies as specified in this Guideline;
- comply with the requirements of paragraph 5.17 "Related Party Transactions";
- comply with the requirements of paragraph 5.18 "Third Party Benefits"; and

DNSP (Distribution Network Service Provider) means the entirety of the activities undertaken by the **Licensee** and/or a **Related Party** of the **Licensee** in order to fulfil the obligations incurred under the **Distribution Licence**.

DNSP Segments comprise the following **Business Segments**:

- **Prescribed Services Segments**; and
- **Excluded Services Segment**

Distribution Licence means a licence to distribute and supply electricity granted under section 195 of the **Electricity Act 1994**.

Entity means a business unit, whether or not a legal entity.

Excluded Services means services as specified in the *Authority's Prescribed Services Determination*.

Excluded Services Segment means the part of the *DNISP* applied to providing *Excluded Services*.

Immaterial item means an item that is not *Material*.

Inter Segmental Cost means a cost that arises from transactions between *DNISP Segments*.

Inter Segmental Income means income that arises from transactions between *DNISP Segments*.

Inter Segmental Transaction means an *Inter Segmental Cost* and *Inter Segmental Income*.

Licensee means the holder of a *Distribution Licence*.

Jurisdictional Regulator means the person authorised by a participating jurisdiction to regulate distribution service prices in that jurisdiction.

Maintenance Costs means those costs which are directly and specifically attributable to the repair and maintenance of property, plant and equipment that are not *Capital Expenditure*. It does not include overhead allocations from other areas of the business.

Material has the meaning set out at paragraph 3.7.1.

Material Provision means a provision other than a provision for -

- income tax;
- deferred taxation;
- dividends payable or receivable; or
- interest payable or receivable;
- included in the provisions reported in the *Regulatory Accounting Statements*, which either at the beginning or end of an accounting period, have a balance of either -
 - \$0.5m or more; or
 - 10% or more of the total provisions in the balance sheet of a *DNISP Segment*.

For the purposes of determining a *Material Provision*, all provision accounts for expenses of a similar nature or brought about by a similar cause, within a *DNISP Segment* shall be aggregated and treated as if they are components of a single provision.

Non-Causal or Non-Causation, Basis or Relationship in relation to a basis of allocation, is one that is other than a *Causal or Causation, Basis or Relationship*.

Not Allocated means the content of those *Account Headings* that are not required by this Guideline to be allocated or attributed to specific *DNISP Segments*.

Operating Costs means those costs which relate to the day to day operations of the business and are not *Maintenance Costs*.

Other activities means activities deriving non-regulated revenue by utilising, in whole or part, assets or other resources that are primarily used for activities fulfilling obligations acquired under the *Distribution Licence*.

Prescribed Services mean the part of the business applied to providing outputs that are regulated by the *Authority's Prescribed Services Determination*.

Regulator means the **Jurisdictional Regulator** of Queensland as defined by the *Electricity Act 1994*.

Regulatory Accounting Date means the date on which a **Regulatory Accounting Period** ends.

Regulatory Accounting Period means a period spanned by **Regulatory Accounting Statements**.

Regulatory Accounting Principles and Policies means accounting principles and policies that have been used to prepare **Regulatory Accounting Statements**, that may be additional to or in place of, the accounting principles and policies used to prepare **Statutory Accounts**.

Regulatory Accounts are financial records derived from the **Statutory Accounts** of the **Licensee** and the **Statutory Accounts** of **Related Parties** of the **Licensee** that are involved in the activities of a **DNSP**.

Regulatory Accounting Statements are financial reports revealing the performance and financial situation of the **DNSP**. They show the originating **Statutory Account** amount, its translation into a **Regulatory Account** amount and its disaggregation between **DNSP Segments**. A schedule of **Regulatory Accounting Statements** are attached to this Guideline in Section 6.

Regulatory Audit Report means an **Auditor's** report on **Regulatory Accounting Statements** prepared in accordance with Australian Auditing Standard AUS 802 as shown in Section 8.

Regulatory Period means a period subject to a price determination.

Related Party means, in relation to a **Licensee**;

- (a) any other **entity** that, at any time during the reporting period, has control or significant influence over the **licensee**;
- (b) any other **entity** that, at any time during the reporting period, is subject to control or significant influence by the **licensee**;
- (c) any other **entity** that, at any time during the reporting period, is controlled by the same **entity** that controls the **licensee** — referred to as a situation in which entities are subject to common control;
- (d) any other **entity** that, at any time during the reporting period, is controlled by the same **entity** that significantly influences the **licensee**;
- (e) any other **entity** that, at any time during the reporting period, is significantly influenced by the same **entity** that controls the **licensee**;

but excludes any other where the **related party** relationship results solely from normal dealings of:

- (f) financial institutions;
- (g) authorised trustee corporations;
- (h) fund managers;
- (i) trade unions;
- (j) statutory authorities;
- (k) government departments; or
- (l) local governments.

Report to the Authority and the Licensee means a detailed report on the conduct of the audit prepared in accordance with Australian Auditing Standard AUS 710 and shall include:

- discussion of any areas of concern;
- discussion on areas of disagreement with the licensee;
- assessment of the clarity and accuracy of the **Regulatory Accounting Statements**;
- assurance that the stated objectives of this Guideline have been met; and

- commentary on compliance with this Guideline.

Remuneration means any money, consideration or benefit, received or due and receivable, in connection with the management of the affairs of the **Licensee**, but does not include:

- amounts in payment or reimbursement of out-of-pocket expenses incurred for the benefit of the **Licensee** or any related business; or
- in relation to a person not resident in Australia who is an **Executive** emoluments received or due and receivable by the person from a holding company:
 - of which he or she is a **Director** or employee; and
 - that is a corporation formed or incorporated outside Australia;
 - being emoluments received, or due and receivable, by the person as such a **Director** or employee.

Retail Activities means those activities associated with the business of selling electricity to customers wherever the customers may be located. **Retail Activities** include but are not necessarily restricted to, those parts of the business that are subject to a **Retail Licence**.

Retail Licence means a licence to sell electricity otherwise than through the market for wholesale trading in electricity operated and administered by the National Electricity Market Management Company, granted under Section 162 of the *Electricity Industry Act 1994*.

Statutory Accounts means the audited set of accounts prepared in accordance with Australian Securities and Investments Commission (ASIC) requirements submitted to the ASIC by statutory entities.

1. INTRODUCTION

- 1.1.1 This Guideline provides for the collection, allocation and recording of business data by the Queensland DNSPs. The information collected by the **Authority** pursuant to this Guideline will provide a comprehensive information base to undertake the necessary financial and economic analysis by the **Authority**. The Authority requires the information to understand **DNSP's** businesses and to perform its functions under the **Code**.
- 1.1.2 The information provided to the **Authority** pursuant to this Guideline will enable the **Authority** to:
- ensure the correct allocation of revenue and costs between a **DNSP's Precluded Services** and **Excluded Services**;
 - regulate distribution prices;
 - measure actual financial performance of **DNSPs** against forecast;
 - publish information on financial performance of **DNSPs**;
 - generally give effect to the objectives of the **Authority** as stated in the **Code** and the **Electricity Act 1994**; and
 - perform other functions under the Code and other Acts.
- 1.1.3 To ensure that the information obtained pursuant to this Guideline is relevant, the **Authority** proposes to amend the Guidelines from time to time to meet the changing needs of the **Authority**. The **Authority** will consult with the **licensees** and other interested parties in respect of such amendments.
- 1.1.4 The **Authority** acknowledges that there may be commercial sensitivity attached to the disclosure of information concerning the non-regulated activities of the **DNSPs** and has no present intention of disclosing such information. The **Authority** will consult with the **licensees** in respect of the disclosure of information about their regulated activities.

2. THE NATURE OF THE GUIDELINE

2.1 Authority and Purpose

2.1.1 The authority to publish this Guideline is contained in clause 6.10.6 of the *Code* that provides for the *Authority* to obtain certified financial statements in a form determined by the *Jurisdictional Regulator* and supports the *Authority's* objectives as stated in Chapter 6 Part D of the *Code*.

2.1.2 Clause 7 of the *Distribution Licences* requires that the *DNSP* must provide:

- the *Regulator* with any information the *Regulator* requests relating to the distribution entity's activities conducted under or in connection with this authority; and
- the *Authority* with any information the *Authority* requests relating to the distribution entity's activities conducted under or in connection with this authority.

2.1.3 Clause 8 of the *Distribution Licences* provides:

- the distribution entity must submit an annual report as directed by the *Regulator* on its operations by 31 July each year, or such other date approved by the *Regulator*, and such other reports as required by the *Regulator*; and
- if the *Regulator* notifies the distribution entity of matters that are to be included in a report, the distribution entity must include those matters in the report.

2.1.4 Paragraph 1 of the *Authority's Electricity Distribution: Ring Fencing Guidelines – Final Determination* require that a *DNSP* must:

- (c) establish and maintain a separate set of accounts in respect of its *Prescribed Services*;
- (d) establish and maintain a separate consolidated set of accounts in respect of the entire business of the *DNSP*, including establishing and maintaining a separate set of accounts in respect of *Excluded Services* provided by the *DNSP*; and
- (e) allocate any costs that are shared between an activity that is covered by a set of accounts described in (c) and any other activity, including any activity performed by another entity, in a manner that ensures there is no cross subsidy, and according to a methodology for allocating costs that is approved by the *Authority*, is generally consistent with the objectives of the National Electricity Code and is otherwise reasonable.

2.2 The Subject

2.2.1 *Regulatory Accounts* and *Regulatory Accounting Statements* must be prepared for a *DNSP* by the *Licensee*. The *DNSP* is not defined by legal entity structures but by the activities undertaken to fulfil the obligations set out in the *Distribution Licence* by the *Licensee* and/or a *Related Party* of the *Licensee*.

2.2.2 Any revenue earned, asset utilised or cost incurred in fulfilling a *Distribution Licence* obligation by the *Licensee* and/or a *Related Party* of the *Licensee* must be reported in the *Regulatory Accounts* and the *Regulatory Accounting Statements*. Whilst the *DNSP* is not defined as a legal entity each revenue, cost element, asset and liability that when combined constitute the whole of the *DNSP* must have its origin in an audited *Statutory Account* or equivalent although not necessarily all from the same set of *Statutory Accounts*.

2.3 The Authority's objectives

2.3.1 Chapter 6 Part D of the *Code* sets out the objectives and principles of the distribution pricing regulatory regime to be administered by the *Jurisdictional Regulator*.

2.3.2 Section 6.10.2 defines aspects that a distribution service pricing regulatory regime must seek to achieve. In particular it states that with respect to the form of regulation, and practical implementation, the following outcomes are particularly relevant:

- an efficient and cost-effective regulatory environment;
- an incentive-based regulatory regime which:
 - provides an equitable allocation between distribution network users and distribution network owners of efficiency gains reasonably expected by the jurisdictional regulators to be achievable by the distribution network owners;
- reasonable recognition of pre-existing policies of governments which are distribution network owners regarding distribution asset values, revenue paths and prices;
- reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of distribution network owners, distribution network users and the public interest; and
- promotion of competition in upstream and downstream markets and promotion of competition in the provision of network services where economically feasible.

2.3.3 Principles of the *Code* with respect to regulation of distribution network pricing (6.10.3) that are relevant to the definition of regulated activities, form and period of regulation, and practical application of that form, include that the regulatory regime must:

- wherever economically efficient and practicable address concerns over monopoly pricing in respect of the distribution network through the introduction of competition in the provision of distribution services;
- provide distribution network owners with incentives and reasonable opportunities to increase efficiency;
- take account of and be consistent with the allocation of risk between network owners and network users;
- provide a fair and reasonable risk-adjusted cash flow rate of return to distribution network owners on efficient investment given efficient operating and maintenance practices on the part of the distribution network owners;
- balance the interests of network users and network owners; and
- take account of relevant previous regulatory decisions made by authorised persons including:
 - the initial revenue setting and asset valuation decisions made by a government at a time at which that government was a distribution network owner in the context of industry reform pursuant to the Competition Principles Agreement;

- decisions made by jurisdictional regulators and any regulatory intentions previously expressed; and
- decisions made by ministers under jurisdictional legislation.

2.3.4 Giving effect to the objectives of section 6.10.2 involves, amongst other things:

- providing historical information to inform periodic price reviews;
- providing information to inform the public, at least annually, about the financial performance of the *DNSP*;
- ensuring correct separation between *Distribution* and non-distribution business costs;
- enabling measurement of actual performance against forecast; and
- assisting in meeting the objectives and performing the functions of the *Authority* as stated in the *Code*.

2.3.5 The Guidelines are minimum requirements. The obligation of a *Licensee* to comply with the *Authority's* Guidelines:

- are additional to any obligation imposed under any other law applying to the *Licensee's* business; and
- do not derogate from such an obligation.

2.4 Definitions and interpretation

2.4.1 In this Guideline

- words and phrases presented in bold italic font *such as this*, are defined in the glossary to this Guideline and have the meaning given to them in that glossary; and
- the words “*shall*” and “*must*” indicate mandatory requirements, unless the overall meaning of the phrase in which one of these words appears, is otherwise.

2.5 Confidentiality

2.5.1 The *Authority's* obligations regarding confidentiality and the disclosure of information provided to it by the Licensee are governed by:

- section 187 of the *Queensland Competition Authority Act 1997*; and
- clauses 6.10.7 and 6.18.2 of the *Code*.

2.5.2 If the *Authority's* intention changes, it will consult with the relevant *Licensee* to ensure that, as far as possible, the concerns of that *Licensee* are taken into account and weighed against the *Authority's* objectives.

2.6 Processes for revision

2.6.1 The *Authority* proposes to amend and expand the Guidelines from time to time to meet the needs of *Licensees*, customers and the *Authority*, in the context of:

- changing circumstances including changes in the regulatory framework;
- developments at the national level and state level;
- the creation of new services and products by *Licensees*; and

- changes to organisational structures by *Licensees*.

2.6.2 In revising this Guideline the *Authority* will, generally:

- state its intention;
- call for input from industry participants and other interested parties;
- have regard to that input, develop a draft and publish it for comment by industry participants and other interested parties; and
- have regard to the comments received on the draft, develop and publish a revised Guideline.

2.7 Input from interested parties

2.7.1 The *Authority* welcomes comments, discussion, or suggestions for amendments to this Guideline, from any interested party. Any contribution in this regard should be addressed to:

The Queensland Competition Authority
Level 19
12 Creek Street
Brisbane 4000
Facsimile: (07) 3222

2.8 Version history and effective date

2.8.1 Every version of the Guideline will be identified by an issue number and date of issue.

2.8.2 This version (Draft Issue No. 1) is issued on 19 December 2000. The Guideline will become effective when issued as a finalised version, expected in March-April 2001. When finalised, this Guideline will apply to all *Regulatory Accounting Periods* ending on or after 30 June 2001.

2.8.3 For all substantial revisions to this Guideline an effective date will be nominated which is expected to be not less than six months prior to the end of the *Regulatory Period* to which it will apply.

2.9 Explanations

2.9.1 Explanations in this Guideline as to why certain information is required are a guide only and should not be taken to limit in any way the *Authority's* objectives, functions or powers.

3. GENERAL PRINCIPLES OF PREPARATION

3.1 Regulatory Accounting Principles and Policies Criteria

3.1.1 *Regulatory Accounting Principles and Policies* must be selected and applied by a *Licensee*:

- such that there is a recognisable and rational economic basis that underlies their utilisation; and
- in a manner which ensures that the resultant financial information satisfies the concepts of relevance and reliability, thereby ensuring that the substance of the underlying transactions and events is reported.

3.1.2 A *Licensee's Regulatory Accounting Principles and Policies* must be disclosed to the *Authority* in a manner which ensures that the *Authority* may understand the resultant *Regulatory Accounting Statements* and can make comparisons between them over time.

3.1.3 *Regulatory Accounting Principles and Policies* shall conform to Australian Accounting Standards where these Standards are applicable, unless a specific requirement of this Guideline requires non-conformity with these Standards.

3.2 Substance to prevail over legal form

3.2.1 *Regulatory Accounting Statements* shall report the substance of transactions.

3.2.2 Where substance and form differ, the substance rather than the legal form of a transaction or event shall be reported.

3.2.3 In determining the substance of a transaction, all its aspects and implications shall be considered, including the expectations of and motivations for, the transaction.

3.2.4 For the purposes of determining the substance of a transaction, a group or series of transactions that achieves, or is designed to achieve, an overall commercial effect shall be viewed in aggregate.

3.3 Information provided shall be verifiable

3.3.1 A *DNSP* must maintain accounting and reporting arrangements which:

- enable *Regulatory Accounting Statements* to be prepared; and
- provide information in the *Regulatory Accounting Statements* that can be verified by reference to *Statutory Accounts*.

3.3.2 Information shall be presented in *Regulatory Accounting Statements* in the most understandable manner, without sacrificing relevance or reliability.

3.4 Regulatory Accounting Statements

3.4.1 *Regulatory Accounting Statements* shall be prepared for the *DNSP*. They shall be derived from the *Statutory Accounts* or their equivalent of the *Licensee* and *Related Parties* of the *Licensee* that contain the entirety of the activities of the *DNSP* by:

- eliminating non-distribution business costs;
- eliminating adjustments not permitted by this Guideline;
- including adjustments that are required by this Guideline;
- not consolidating amounts from *Statutory Accounts* of different *Entities*; and

- consolidating or disaggregating *Statutory Account* amounts within an *Entity* in order to conform to the prescribed form of *Regulatory Accounting Statements*.
- 3.4.2 Where a *Statutory Account* amount has been consolidated or disaggregated in the *Regulatory Accounting Statements* a worksheet must accompany the *Regulatory Accounting Statements* reconciling the *Statutory Account* amount shown in the *Regulatory Accounting Statement* to the *Statutory Account* amount in the *Statutory Accounts* of the *Entity*.
- 3.4.3 The movement from *Statutory Account* to *Regulatory Account* will be clearly reported in the *Regulatory Accounting Statements*.
- 3.4.4 If some or all of the activities of a *DNSP* are carried out in an *Entity* that does not have *Statutory Accounts* all financial representations of distribution activities in such an *Entity* must be audited by the external independent *Auditors* engaged to undertake the *Regulatory Audit* in a manner identical to the auditing of *Statutory Accounts*.

Cost Allocation

- 3.4.5 The allocation of *Statutory Accounts* between *DNSP* and non-distribution business activities and across *DNSP Segments* shall be based on the principle that:
- items which are *Directly Attributable* to the *DNSP* and *DNSP Segment* are assigned accordingly; and
 - items not *Directly Attributable*, shall be allocated to the *DNSP* and across *DNSP Segments* using an appropriate allocator, as indicated in following paragraphs.
- 3.4.6 An item may be *Directly Attributable* to the *DNSP* but not *Directly Attributable* to a *DNSP Segment*. In this circumstance the allocation across *DNSP Segments* will be made using an appropriate allocator as indicated in the following paragraphs.
- 3.4.7 Items that are not *Directly Attributed*, are to be allocated on a *Causation Basis*. Allocation based on avoidable cost is not permitted.

Explanation

- 3.4.8 Avoidable cost as an allocation base attributes the total cost of a good or service to one cost centre on the basis that the cost will unavoidably be incurred by that cost centre irrespective of whether or not it is now shared with another cost centre. The *Authority* requires that a cost be allocated across all cost centres that benefit from the service or good.
- 3.4.9 A *Licensee* shall produce for each item that has not been *Directly Attributed* to the *DNSP and/or DNSP Segment* a supporting work paper that includes:
- the amounts that have been allocated to the *DNSP* and/or *DNSP Segment* and amounts that have not been so allocated; and
 - the numeric quantity of each allocator.
- 3.4.10 If an item is *Immaterial* and a *Causal Relationship* cannot be established without undue cost and effort, the *Licensee* shall provide the *Authority* with a separate list of these items indicating a description and amount. The *Licensee* may effect an allocation of these items on a *Non-Causal Basis*, provided it is accompanied by a supporting note documenting for each such item:
- a defensible basis of allocation which shall not be avoidable cost;
 - the reason for choosing that basis; and
 - an explanation why no *Causal Relationship* could be established.

3.4.11 **Non Causal Bases** of allocation shall only be applied to the extent that the aggregate of all items subject to all **Non Causal Bases** of allocation, is not **Material** to the **Regulatory Accounting Statements**. Paragraph 3.7 sets out **the Authority**'s standard of materiality.

3.4.12 Bases of allocation will be subject to the specific approval of the **Authority**. The **Authority** expects to only accept a **Non Causal Basis** if a **Licensee** can demonstrate that there is likely to be a strong positive correlation between the **Non Causal Basis** and the actual cause of resource or service consumption or utilisation that those costs represent.

3.5 Regulatory asset values

3.5.1 Depreciated Optimised Replacement Cost method shall be used to determine fixed asset balances in the **Regulatory Accounts** Balance Sheet for the **DNSP**.

3.5.2 Asset revaluations are not permitted unless they are specifically agreed to or required by the **Authority**. Revaluations made in **Statutory Accounts** that have not been agreed to by the **Authority** must be eliminated via regulatory adjustments to ascertain the **Regulatory Account** value.

3.5.3 Capital work-in-progress must not be shown under a work-in-progress heading. Instead capital works expenditure must be recorded against the asset category appropriate to that expenditure.

3.5.4 Goodwill is not permitted in **Regulatory Accounts**. It will be eliminated as an adjustment between **Statutory and Regulatory Accounts**.

3.6 Time consistent application of accounting policies, unless disclosed otherwise.

3.6.1 A **Licensee** shall present on a fair and consistent basis, from the accounting records that underlie its **Regulatory Accounts** the costs, revenues, assets employed and liabilities that may be reasonably attributed to the **DNSP**.

3.6.2 **Regulatory Accounting Statements** must, in so far as is reasonably practicable, be prepared in accordance with the general rules and format, and subject to the disclosure provisions of paragraph 3.6.3 below, use the accounting principles and policies applicable to the **Statutory Accounts**.

3.6.3 A **Licensee** shall provide to **the Authority** full and detailed documentation of:

- any **Regulatory Accounting Principles and Policies** that it may have used to prepare the **Regulatory Accounting Statements**, that may be additional to or in place of, the accounting principles and policies used to prepare its **Statutory Accounts**; and
- any changes since the preceding **Regulatory Accounting Statements** were prepared, in either the accounting principles and policies used to prepare its **Regulatory Accounts**, or its **Regulatory Accounting Principles and Policies**. Where there is such a change a **Licensee** shall disclose to the **Authority**:
 - the nature of the change;
 - the reasons for the change; and
 - the effect of the change on the **Regulatory Accounting Statements**.

3.7 Materiality

3.7.1 An item is **Material** if its omission, misstatement or non-disclosure has the potential to prejudice the understanding of the financial position and nature of the **DNSP**, gained by reading the **Regulatory Accounting Statements**.

3.7.2 This Guideline shall apply to all **Material** items in the **Regulatory Accounts** and **Regulatory Accounting Statements** of a **DNSP**.

3.8 Accounting records

3.8.1 A **Licensee's Directors** are responsible for the preparation and presentation of the **Regulatory Accounts** and **Regulatory Accounting Statements**, and the information they contain.

3.8.2 A **Licensee's Directors** shall ensure that a **Licensee** keeps accounting records that:

- correctly record and explain the transactions and financial position of the **DNSP**;
- enable **Regulatory Accounts** and **Regulatory Accounting Statements** to be prepared in accordance with this Guideline; and
- allow an **Auditor** to conveniently and properly form an opinion on the **Regulatory Accounts** and **Regulatory Accounting Statements** in accordance with the requirements of this Guideline.

3.8.3 A **Licensee's Directors** shall also ensure that the **Licensee** retains the accounting records from which **Regulatory Accounts** and **Regulatory Accounting Statements** are prepared for a period of no less than seven years after the completion of the transactions to which they relate.

3.9 Directors' Responsibility Statement

3.9.1 A **Directors' Responsibility Statement** shall be attached to a **DNSP's Regulatory Accounting Statements**.

3.9.2 The **Directors' Responsibility Statement** shall be signed and dated by a **Director** of the **Licensee**.

3.9.3 Section 7 sets out the format of a **Director's Responsibility Statement**.

4. PROCUREMENT OF AN AUDIT OPINION

4.1 Introduction

4.1.1 The information presented in the *Regulatory Accounting Statements* must be adequately and independently audited.

4.2 Primary duty of care to the Authority

4.2.1 Audits should be conducted objectively and independently. This is guaranteed in large part by the competence and professionalism of the audit firm. Additional measures are needed to reinforce the integrity of the audit process and promote stakeholder confidence in it. This is particularly important given that the *Auditors* are paid by the *Licensee*.

4.2.2 Accordingly, the *Auditor* must have a formal duty of care to *the Authority* to conduct audits independently and objectively. *Auditors* may be placed in a position of conflict between their duty to the *Licensee* and their duty to the *Authority*; in such an event, the *Auditor's* primary duty must be to the *Authority*.

4.2.3 The duty of care will be formalised in a tripartite deed between the *Authority*, the *Licensee* and the *Auditor* to ensure that it is directly enforceable by the *Authority*.

4.3 Appointing the Auditor

4.3.1 The audit firm selected by the *Licensee* will require formal approval from the *Authority* for the subsequent audit to be acceptable.

4.3.2 To obtain approval the *Licensee* must submit an annual request for approval. Satisfactory execution of previous audits will be an important consideration in the *Authority's* decisions on the approval of auditors.

4.3.3 The audit team must be led by a senior member of the audit firm. The team leader must sign and take responsibility for the *Audit Report*.

4.3.4 The audit team must comprise qualified, experienced personnel possessing no less a standard of expertise than would be required to conduct *Statutory Account* audits acceptable to the Australian Securities and Investments Commission.

4.3.5 The Guideline requirements, including those for independence, extend to any sub-contractors engaged by the audit firm.

4.4 Audit Objectives

4.4.1 The *Auditor's* primary objective is to ensure that *Regulatory Accounting Statements* comply with the objectives as set out in section 2.3.1 of this Guideline. Strict compliance with those objectives may require the *Auditor* to direct changes to *Regulatory Accounting Statements* even though their form does not contravene the letter of this Guideline.

4.4.2 The *Auditor's* secondary objective is to assure compliance with this Guideline in detail in so far as that does not conflict with the primary objective detailed above.

4.4.3 *Regulatory Accounting Statements* for *Regulatory Accounting Periods* ending on or after 30 June 2001 shall be subject to an *Auditor's* opinion in accordance with the requirements of this Guideline.

- 4.4.4 **Licensees** are responsible for ensuring that a signed **Regulatory Audit Report** and a **Report to the Authority and the Licensee** (where appropriate) are delivered to the **Authority** by the end of the fourth calendar month following the end of the **Regulatory Accounting Period**.
- 4.4.5 Section 8 shows the form of the **Regulatory Audit Report**.
- 4.4.6 Where a **Regulatory Audit Report** or **Report to the Authority and the Licensee** is critical of or highlights deficiencies in **Regulatory Accounting Statements, the Authority, Licensee** and **Auditor** shall meet to discuss those issues. The **Authority** may require the **Licensee** to amend the **Regulatory Accounting Statements** in response to those criticisms and/or deficiencies.
- 4.4.7 Specific note must be taken of the definition of a **DNSP** and the scope of the **Regulatory Accounting Statements** as defined by this Guideline in paragraphs 2.2.1 and 2.2.2 and 3.4.4.

5. INFORMATION REQUIREMENTS

5.1 Regulatory Accounting Statements

5.1.1 *Regulatory Accounting Statements* shall be prepared in accordance with this Guideline.

5.1.2 A *Licensee* shall also deliver to the *Authority*:

- the section/s of the *Statutory Accounts* of the *Entity* or Entities that have been aggregated to provide the *Regulatory Accounting Statements*;
- a *Regulatory Audit Report* and *Report to the Authority and Management* (where appropriate) on *Regulatory Accounting Statements* for *Regulatory Accounting Periods* ending on or after 30 June 2001, in the form specified in Part 4 of this Guideline;
- a *Directors' Responsibility Statement* for the *Regulatory Accounting Statements*; and
- the accounting principles and policies and any details of changes or developments.

5.1.3 Section 6 to this Guideline, defines a mandatory schedule of *Regulatory Accounting Statements*.

5.1.4 Section 6 to this Guideline also broadly defines how *Regulatory Accounting Statements* and certain supporting notes and work papers, shall be set out.

5.2 Timing

5.2.1 A *Licensee* shall deliver to the *Authority* the information specified in this Guideline within 4 calendar months of the end of the *Regulatory Accounting Period* to which the *Regulatory Accounting Statements* relate.

5.3 Regulatory Accounting Periods

5.3.1 A *Regulatory Accounting Period* shall be a financial year unless the *Authority* should specify otherwise.

5.3.2 A *Regulatory Accounting Period* shall cover a continuous period.

5.4 Disaggregation

Distribution and Non Distribution Allocation

5.4.1 The allocation of *Statutory Account* amounts between the *DNSP* and the non-distribution business parts of an *Entity* must be made in accordance with the allocation principles detailed in paragraph 3.4 of this Guideline.

DNSP Segment Allocation

5.4.2 After the allocation of *Statutory Account* amounts between the *DNSP* and the non-distribution business a further allocation across *DNSP Segments* will be necessary. This allocation must also be made in accordance with the allocation principles detailed in paragraph 3.4 of this Guideline.

Inter Segmental Transactions

5.4.3 Transactions between *DNSP Segments* must not be netted off. They shall be recorded in the profit and loss accounts of the *DNSP Segments* in which they arise and be separately disclosed.

5.5 Operating and Maintenance Costs

Disclosure

5.5.1 The **Regulatory Accounting Statements** shall:

- disclose **Maintenance Costs** separately from **Operating Costs**;
- disclose **Operating Costs** in a manner defined in Section 6;
- disclose **Maintenance Costs** in a manner defined in Section 6;
- disaggregate the **Operating** and **Maintenance** costs of the **DNSP** in a manner defined in Section 6; and
- provide or explain the link to, the **Statutory Account** that is the source for amounts allocated to each activity associated with **Operating Costs** and each asset category associated with **Maintenance Costs**.

Cost Attribution or Allocation

5.5.2 **Operating** and **Maintenance** costs shall be either **Directly Attributed** to the **DNSP** and **DNSP Segment** or allocated on a **Causation Basis** in accordance with the principles set out in paragraph 3.4 of this Guideline.

5.5.3 The allocation of a cost should reflect the consumption, or utilisation, of a resource or service as referred to in paragraph 3.4 of this Guideline.

Disclosure of Bases Of Cost Allocation

5.5.4 In disaggregating **Operating** and **Maintenance** costs between distribution and non-distribution businesses and for the **DNSP** across **DNSP Segments**, a cost may be considered to be either:

- a cost that can be **Directly Attributed** wholly and exclusively; or
- an indirect cost that needs to be allocated on the bases of the principles set out in paragraph 3.4 of this Guideline.

5.5.5 The **Regulatory Accounting Statements** shall include a note that discloses for each **Operating** cost activity area and each **Maintenance** cost asset category:

- the amount of costs within the activity area or asset category, that can be **Directly Attributed**; and
- the total costs allocated and:
 - a description of the basis of allocation used;
 - a quantification of the allocators applied; and
 - the corresponding amount of cost allocated.

5.5.6 The total of the costs for which this information is disclosed shall agree to the total **Operating** and **Maintenance** costs disclosed by the note described in paragraph 5.5.1.

5.6 Depreciation

5.6.1 A depreciation charge should be attributed to the *DNISP* and the *DNISP Segment* that employs the asset that gives rise to the charge in accordance with the principles set out in paragraph 3.4 of this Guideline.

5.6.2 The *Regulatory Accounting Statements* need to fairly state the financial position of each *DNISP Segment*.

Accounting policy

5.6.3 Depreciation charges on assets accounted for within the *DNISP Segments* shall:

- be accounted for on a straight line basis; and
- use economic asset lives.

5.7 Other expenditure

Restatement of principle

5.7.1 Other expenditure arising in the profit and loss account not specifically addressed elsewhere in Part 5 of this Guideline, shall be disaggregated between the distribution business and non-distribution business and the *DNISP Segments* in accordance with:

- the general principles set out in Part 3 of this Guideline; and
- the disclosure requirements set out in Section 6.

5.8 Abnormal items

5.8.1 Where they arise, abnormal items should be disclosed in the *Regulatory Accounts* and attributed or allocated in accordance with paragraph 3.4.

Tax effect

5.8.2 The tax effect and after tax abnormal amount shall be disclosed.

Explanation

5.8.3 The *Authority* needs to understand the profits and losses accruing to the *DNISP* prior to income tax.

Disaggregation

5.8.4 An abnormal item stated prior to related income tax, should be attributed to the *DNISP* and the *DNISP Segment* as follows:

- if the item can be *Directly Attributed* to a single *DNISP Segment*, or if it has discrete components that can each be so attributed, then the item or the components so identified, should be *Directly Attributed* to the *relevant DNISP Segments*;
- to the extent that an item cannot be *Directly Attributed*, then it should be allocated to *DNISP Segments* in accordance with the requirements of paragraph 3.4;
- where it is necessary to analyse an item into components to effect *Direct Attribution* or allocation, a note should be appended to the *Regulatory Accounting Statements* describing:
 - the monetary amount of each component; and

- its characteristics that either allow it to be ***Directly Attributed*** to a ***DNBP Segment***, or require it to be allocated across ***DNBP Segments***.

Explanation

5.8.5 Abnormal items should be attributed to ***Business Segments*** following attribution principles consistent with those applied to other account items.

5.9 Income tax attributable to operating profit

5.9.1 ***The Authority*** requires information about the income tax charged to the ***DNBP***.

5.10 Interest & Dividends

5.10.1 ***The Authority*** requires information about interest expenses, dividend and dividend payout ratio together with any corresponding assets or liabilities that may arise in the balance sheet.

5.11 Disaggregation of Fixed Assets

5.11.1 Fixed Assets shall be either ***Directly Attributed*** to the ***DNBP*** and ***DNBP Segment*** or allocated on a ***Causation Basis*** in accordance with the principles set out in paragraph 3.4 of this Guideline. Where assets are used in both ***Distribution*** and non-distribution business areas and in more than one business segment the asset will need to be appropriately apportioned between them.

Disclosure

5.11.2 The ***Regulatory Accounting Statements*** shall include a note that discloses for each asset category the value of assets that are an allocation rather than whole assets and:

- a description of the basis of allocation used;
- a quantification of the allocators applied; and
- the corresponding amount of cost allocated.

5.11.3 Additions and decrements shall be disclosed separately and not netted off.

5.11.4 Transfers between asset categories shall be disclosed separately and not netted off.

5.11.5 The ***Regulatory Accounting Statement*** Guidelines in Section 6, show how Assets will be reported.

5.11.6 Opening Fixed Asset values in the ***Regulatory Accounting Statements*** must equal closing Fixed Asset values from the preceding ***Regulatory Accounting Period***.

5.12 Asset Categories

5.12.1 Assets shall be reported by the ***Asset Categories*** to fulfil the reporting requirements specified in Section 6 for the purposes of reporting balances and movements in the gross book value, accumulated depreciation and hence, the net book value of the assets utilised in the ***DNBP***.

5.12.2 ***Asset Categories*** defined in the Regulatory Accounting Statements prepared against the Guidelines of Section 6 shall be applied consistently between ***Regulatory Accounting Periods***.

5.13 Capital Contributions

5.13.1 Where a *DNISP* credits capital contributions to asset values, the *DNISP's Regulatory Accounting Statements* shall disclose the amount of customer contributions credited to asset balances in accordance with the allocation principles defined in Section 6 of these Guidelines.

5.13.2 The *Authority* requires an understanding of customer contributions received and their relationship to movements in asset balances.

5.14 Inflation Accounting Adjustments

5.14.1 No adjustments for inflation will be made to *Regulatory Accounts*.

5.15 Other Balance Sheet Items and Statement of Cash Flows

Restatement of principles

- Balance sheet and statement of cash flow items not specifically addressed in Part 5 of this Guideline, shall be disaggregated between *DNISP Segments* in accordance with the general principles set out in Part 3 of this Guideline; and
- the disclosure requirements set out in Section 6.

5.16 Movements in provisions

5.16.1 Work papers shall be added to the *Regulatory Accounting Statements* sufficient to provide a reconciliation and explanation of all provisions disclosed by the *Regulatory Accounting Statements*.

5.16.2 The disaggregation of provisions must follow the principles set out in paragraph 3.4.

Disclosure

5.16.3 The following information shall be provided for each *Material Provision* and in total for all other provisions in the *DNISP*:

- the balance at the beginning of the *Regulatory Accounting Period*;
- amounts set aside to provisions;
- expenditure charged to provisions;
- amounts written back from provisions;
- the net movement charged or credited to the profit and loss account; and
- the balance at the end of the *Regulatory Accounting Period*.

Explanation

5.16.4 The *Authority* needs to understand the effect of provisions on costs disclosed by the *Regulatory Accounting Statements*.

5.17 Related Party Transactions

5.17.1 The *DNISP* is defined by its activities not by incorporation. All costs incurred by the *DNISP* must be reported at cost. Entities that are a *Related Party* of the *DNISP* as defined in the Glossary to this Guideline are considered part of the *DNISP*. The value of goods and services

originating in those *Related Parties* must be recorded at cost in the *Regulatory Accounting Statements*.

5.18 Third Party Benefits

5.18.1 Where the *Regulatory Accounting Statements* record transactions associated with any subcontracting, purchase or other arrangements, that cause:

- the *Licensee*; or
- any *Related Party* of the *Licensee* to enjoy a material beneficial interest in income, or other value that accrues in the hands of a third party, the *Licensee* shall disclose for each such arrangement;
 - a description of the arrangement;
 - its underlying purpose;
 - details of the counter party;
 - details of the third parties;
 - the monetary value of such transactions that arose in the *Regulatory Accounting Period*
 - the basis of charge for the transaction entered into by the *Licensee*;
 - the basis of calculation of the corresponding benefit received by the *Licensee* or the *Related Party*; and
 - a summary of the associated accounting entries, analysed by *Regulated Business Segment*, that have been recorded in the *Regulatory Accounting Statements*.

5.18.2 The disclosure required under paragraph 5.18.1 shall be a statement attached to the *Regulatory Accounting Statements*.

5.18.3 The *Directors' Responsibility Statement* shall include a specific affirmation that either:

- no such transactions arose; or
- the disclosure requirements of paragraph 5.18 have been complied with.

5.19 Other Information

5.19.1 A *Licensee* shall disclose the non-financial information requested by Section 9 of these Guidelines in a statement attached to the *Regulatory Accounting Statements*.

Explanation

5.19.2 There are certain items required by the *Authority* to help understand the *DNSPs* that are not routinely submitted or obtained elsewhere.

6. REGULATORY ACCOUNTING STATEMENTS

Determining the exact structure and content of the *Regulatory Accounting Statements* is the responsibility of the *DNSP*. However, the *Regulatory Accounting Statements* should be prepared in accordance with the allocation principles detailed in paragraph 3.4 of this Guideline. Further, the *DNSP* must seek the *Authority's* approval on the format and structure of the *Regulatory Accounting Statements* prior to their submission.

At a minimum a *DNSP* should prepare the following *Mandatory Regulatory Accounting Statements*:

- Regulatory Profit and Loss Statement;
- Regulatory Balance Sheets;
- Analysis of Operating and Maintenance Expenditure;
- Analysis of Provisions;
- *Non-Causal* Allocations; and
- Distribution Revenue.

As a minimum disaggregation requirement, the *Authority* requires that the *Regulatory Accounting Statements* be separated to demonstrate reporting on:

- Audited Statutory Accounts;
- Distribution Business;
- *Excluded Services*;
- *Prescribed Services*;
- Other; and
- *Not Allocated*.

In addition, in preparing the *Regulatory Accounting Statements* it is mandatory to produce for each cost or revenue item that has been allocated to the *Regulated Business Segments* a supporting workpaper that includes the following:

- the amounts that have been directly attributed to each business segment;
- the amounts that have been allocated to each business segment;
- a description of the allocation basis; and
- the numeric quantity of each allocator.

7. PRO FORMA DIRECTORS' RESPONSIBILITY STATEMENT

In the opinion of the Director/s of [name of licensee]:

- the Regulatory Accounting Statements set out on pages [] to [] are drawn up so as to present fairly in accordance with the requirements of the “Regulatory Information Requirements” (“the Guideline”) issued by the Queensland Competition Authority, dated [version date];
 - the results of each Business Segment for the Regulatory Accounting Period ended [period end];
 - information concerning the state of affairs at [period end], of each Business Segment;
 - information required by paragraph 5.17 of the Guideline
 - information concerning all Third Party Benefit Transactions required by paragraph 5.18 of
 - the Guideline; [delete if inapplicable] and
- no Third Party Benefit Transactions arose during the Regulatory Accounting Period that require disclosure under paragraph 5.18 of the Guideline [to be deleted only if disclosure is confirmed above]; and

The terms and definitions used in this statement accord with the definitions set out in the Guideline referred to above.

Signed in accordance with a resolution of Directors:

(name of director) Dated
Director

(name of director) Dated
Director

8. EXAMPLE REGULATORY AUDIT REPORT

(Date)

REGULATORY ACCOUNTING STATEMENTS PERIOD ENDED *period end*

Scope

We have audited the Regulatory Accounts and Regulatory Accounting Statements of name of Licensee (“Licensee”) for the Regulatory Accounting Period ended *period end*, comprising profit and loss account, balance sheet, statement of cash flows and accompanying notes, set out on pages __ to __.

The Licensee’s directors are responsible for the preparation and presentation of the Regulatory Accounting Statements and the information they contain. The Directors’ have determined that the accounting principles and policies used are appropriate to meet the requirements of the Regulatory Information Requirements. We have conducted an independent audit of the Regulatory Accounts and Regulatory Accounting Statements in order to express an opinion on them to the Queensland Competition Authority (the Authority) and the Licensee on their preparation and presentation.

The Regulatory Accounts and Regulatory Accounting Statements have been prepared for the purpose of fulfilling the requirements of the Authority as laid out in the *Electricity Distribution: Regulatory Accounting and Information Guidelines*. This report is prepared for the Authority and the Licensee and is not to be used for any other purpose than those specified herein. We disclaim any assumption of responsibility for any reliance on this report, or on the Regulatory Accounting Statements to which it relates, to any person other than that for which it was prepared.

Our audit has been conducted in accordance with Australian Auditing Standards. Our procedures included examination, on a test basis, of evidence supporting the amounts and other disclosures in the Regulatory Accounting Statements, and the evaluation of significant accounting estimates. These procedures have been undertaken to form an opinion as to whether, in all material respects, the Regulatory Accounts and Regulatory Accounting Statements are presented fairly in accordance with the Regulatory Accounting Principles and Policies and Regulatory Information Requirements. These Regulatory Accounting Principles and Policies do not require the application of all Accounting Standards nor other mandatory professional reporting requirements (Urgent Issues Group Consensus Views).

The audit opinion expressed in this report has been formed on the above basis.

Audit Opinion.

In our opinion, the Regulatory Accounts and Regulatory Accounting Statements present fairly in accordance with the Regulatory Information Requirements the financial position of name of Licensee as at period end, the results of its operations and its cash flows for the period then ended.

Yours faithfully
(name of Auditor)

Chartered Accountants
(name of signatory)
Position of signatory

9. ADDITIONAL INFORMATION REQUIREMENTS

Reliability indices descriptions

Average minutes off supply per customer

- Definition: Total minutes, on average, that customers are without electricity in a year, and includes both planned and unplanned minutes off supply.
- Index: System Average Interruption Duration Index – SAIDI.
- Calculation:
$$\frac{\sum_{\text{interruptions}} [\text{Interruption duration (minutes)} \times \text{Number of customers affected}]}{\text{Total number of customers}} \quad \text{mins / period}$$

Average number of interruptions per customer

- Definition: The average number of occasions per year each customer is interrupted.
- Index: System Average Interruption Frequency Index – SAIFI.
- Calculation:
$$\frac{\text{Total number of interruptions}}{\text{Total number of customers}} \quad \text{interruptions/customer/period}$$

Average interruption duration

- Definition: Average duration of each interruption (=SAIDI/SAIFI).
- Index: Customer Average Interruption Duration Index – CAIDI.
- Calculation:
$$\frac{\sum_{\text{interruptions}} [\text{Interruption duration} \times \text{Number of customers affected}]}{\text{Total number of interruptions}} \quad \text{mins/interruption}$$

Average number of momentary interruptions per customer

- Definition: Total number of momentary interruptions per customer per period.
- Index: Momentary Average Interruption Frequency Index – MAIFI.
- Calculation:
$$\frac{\text{Number of momentary interruptions}}{\text{Total number of customers}} \quad \text{interruptions/customer}$$

Reporting for reliability measures

Data to be collected on a per feeder basis.

Reporting Specification is made up of five sections:

1. Administrative Data;
2. Aggregate Data;
3. Reliability Data;
4. Quality of Supply Data; and
5. Customer Service Data.

Item No.	DATA FIELD	DEFINITION	REPORTING PERIOD
1	Administrative Data		
1.1	DNSP business	ie: Ergon Energy/Energex.	Monthly
1.2	Start date	First day of reporting period.	Monthly
1.3	End date	Last day of reporting period.	Monthly
1.4	Region	Classification of region served by feeder: CBD, urban, rural, remote.	Monthly
1.5	Feeder ID	Code used by DNSP.	Monthly

Item No.	DATA FIELD	DEFINITION	REPORTING PERIOD
2	Aggregate Data		
2.1	Total distribution customers	<ul style="list-style-type: none"> — The customer numbers on which minutes off supply and interruption figures are based (for the business, business centres, and feeders). — The sum of domestic and non-domestic customer numbers may not balance with this figure. 	Monthly
2.2	Domestic distribution customers	<p>A distribution customer is defined as a supply point through which electricity is distributed to an end user with a separate account.</p> <ul style="list-style-type: none"> — Unmetered supplies are included. — All distribution customers in the DNSP's area to be counted (ie: including 'lost' retail customers, and excluding 'won' retail customers in other DNSPs' areas). — The number of customers at the end of the reporting period to be reported. 	Monthly
2.3	Non-Domestic distribution customers	See Item No. 2.2: 'Domestic distribution customers'.	Monthly
2.4	Length of high voltage overhead distribution lines	<p>Route length in kilometres of lines in service (the total length of feeders including all spurs).</p> <ul style="list-style-type: none"> — Each SWER line, single phase line, and three phase line counts as one line. — A double circuit line counts as two lines. 	Annual
2.5	Length of high voltage underground distribution lines	See Item No. 2.4: 'Length of high voltage overhead distribution lines'.	Annual
2.6	Maximum demand (MVA)	Maximum demand over the reporting period for the feeder, calculated from the nominal feeder voltage and maximum feeder current.	Annual

Item No.	DATA FIELD	DEFINITION	REPORTING PERIOD
3	Reliability Data		
3.1	Reliability of supply complaints	The number of complaints of relating to the reliability of supply.	Quarterly
3.2	Unplanned outages	<ul style="list-style-type: none"> — Unplanned events causing interruptions to customers on the high voltage and low voltage systems. — Does not include momentary outages and single premise outages. 	Monthly
3.3	Momentary feeder outages	<ul style="list-style-type: none"> — A momentary outage is an outage less than 1 minute in duration. — A feeder outage includes any outage of an entire feeder (including due to a sub-transmission fault) and does not include an outage of a feeder section. — Each successful auto re-close is counted as one momentary outage. — Re-closes which are followed by lock-out are to be included in the unplanned outage indicator, not the momentary outage indicator. 	Monthly
3.4	Momentary feeder section outages	<ul style="list-style-type: none"> — A momentary outage is an outage less than 1 minute in duration. — Includes outages of a feeder section; feeder outages are not included. — Each successful auto re-close is counted as one momentary outage. — Re-closes which are followed by lock-out are to be included in the unplanned outage indicator, not the momentary outage indicator. 	Annual
3.5	Planned outages	<p>Planned events causing interruptions to customers.</p> <ul style="list-style-type: none"> — Does not include single premise outages. 	Monthly
3.6	Unplanned minutes off supply	<p>To be reported as gross (or aggregate) unplanned customer minutes off supply per customer.</p> <ul style="list-style-type: none"> — An interruption begins when supply is lost, not when the interruption is reported. — Where there is no automatic recording of the duration of an interruption, the best estimate is to be recorded. — When reported for a feeder, minutes off supply for the customers on that feeder at the end of the reporting period should be reported. — Includes single premise interruptions . — Does not include momentary interruptions. 	Monthly
3.7	Planned minutes off supply	<p>To be reported as gross (or aggregate) planned customer minutes off supply per customer.</p> <ul style="list-style-type: none"> — Includes single premise interruptions. 	Monthly
3.8	Unplanned interruptions	<p>Customer interruptions caused by unplanned outages.</p> <ul style="list-style-type: none"> — Includes single premise interruptions. — Does not include momentary interruptions. 	Monthly
3.9	Momentary interruptions (due to feeder outages)	Customer interruptions caused by momentary feeder outages.	Annual
3.10	Planned interruptions	<p>Customer interruptions caused by planned outages.</p> <ul style="list-style-type: none"> — Includes single premise interruptions. 	Monthly
3.11	Energy not supplied - unplanned (MWh)	<p>Estimate of energy not supplied to be based on average customer demand (multiplied by number of customers interrupted and the duration of the interruption).</p> <p>Average customer demand to be determined from (in order of preference):</p> <ul style="list-style-type: none"> — average consumption of the customers interrupted based on their billing history; — feeder demand at the time of the interruption divided by the number of customers on the feeder; — average consumption of customers on the feeder based on their billing history; and — average feeder demand derived from maximum demand and estimated load factor, divided by the number of customers on the feeder. 	Annual
3.12	Energy not supplied - planned (MWh)	See Item No. 3.11: 'Energy not supplied – unplanned (MWh)'.	Annual

Item No.	DATA FIELD	DEFINITION	REPORTING PERIOD
4	Quality of Supply Data		
4.1	Quality of supply complaints	Complaints of quality of supply – over-voltage.	Quarterly
4.2	Over-voltage events due to high voltage injection	The number of over-voltage events in the distribution or transmission system leading to at least one customer complaint.	Annual
4.3	Customers receiving over-voltage due to high voltage injection	The estimated number of customers affected by over-voltage events, based on customer complaints and the DNSP's investigation.	Annual
4.4	Over-voltage events due to lightning	The number of over-voltage events in the distribution or transmission system leading to at least one customer complaint.	Annual
4.5	Customers receiving over-voltage due to lightning	The estimated number of customers affected by over-voltage events, based on customer complaints and the DNSP's investigation.	Annual
4.6	Over-voltage events due to voltage regulation or other cause	The number of over-voltage events in the distribution or transmission system leading to at least one customer complaint. — Includes events due to unknown cause.	Annual
4.7	Customers receiving over-voltage due to voltage regulation or other cause	The estimated number of customers affected by over-voltage events, based on customer complaints and the DNSP's investigation. — Includes events due to unknown cause.	Annual

5	Customer Service		
5.1	Calls to network call centre	All calls to the network call centre to be reported, including any answered by an automated response service and terminated without being answered by an operator.	Quarterly
5.11	Calls to network call centre forwarded to an operator	Includes abandoned calls not answered within 30 seconds.	Quarterly
5.12	Calls to network call centre answered within 30 seconds	The time to answer begins when the call is diverted to an operator, and includes any time spent in a queue.	Quarterly
5.2	Customer arranged appointments	Appointments requested by the customer for a meeting with the DNSP's staff, at any location.	Quarterly
5.21	Appointments not met within 15 minutes of agreed time	The number of appointments, requested by a customer for a meeting with the DNSP's staff, not met within 15 minutes of appointed time.	Quarterly
5.3	Connections made	The number of supply connections made to customers' premises.	Quarterly
5.31	Connections not made on agreed date	The number of connections to customers' premises made after the date agreed to with the customer.	Quarterly
5.32	Connections 4 day delay	The number of supply connections to customers' premises that are one to four business days after the date agreed with the customer.	Quarterly
5.33	Connections 5+ day delay	The total number of supply connections to customers' premises that are five or more business days after the date agreed with the customer.	Quarterly
5.34	Connection & augmentation complaints	Includes complaints about: <ul style="list-style-type: none"> — the quality and timeliness of a new connection; and — the cost, timeliness and quality of augmentation works. 	Quarterly
5.4	Street lights	The number of street lights in the distribution area.	Quarterly
5.41	Street lights out during period	The number of street lights reported by customers as not working.	Quarterly
5.42	Street lights not repaired by agreed date	The total number of street lights reported as not working which were not fixed by the date agreed with the customer.	Quarterly
5.43	Street lights not repaired within 2 working days	The total number of street lights that were reported as not working which were not fixed within 2 business days of the customer's report.	Quarterly
5.5	Number of GSL payments made	The total number of events that attracted a GSL payment	Quarterly
5.51	Amount paid out in GSL payments	The total amount paid in GSL payments	Quarterly
5.6	Planned interruptions for which 4 days notice not given	The number of planned interruptions of which customers were given less than four days notice.	Quarterly
5.7	General complaints - distribution	Includes any complaints about the quality and timeliness of service provided by the DNSP not covered elsewhere, for example in relation to: <ul style="list-style-type: none"> — fault repair; — vegetation control; — request for information on quality and reliability of supply; and — other service issues. 	Quarterly

**APPENDIX E: TASMAN ASIA PACIFIC AND PACIFIC ECONOMICS GROUP
SUMMARY EFFICIENCY REPORT**

TASMAN ASIA PACIFIC

&

PACIFIC ECONOMICS GROUP

**OPERATIONS AND MAINTENANCE
COST BENCHMARKS FOR
QUEENSLAND ELECTRICITY
DISTRIBUTION BUSINESSES —
OVERVIEW OF FINDINGS**

PREPARED FOR THE QUEENSLAND COMPETITION AUTHORITY

23 NOVEMBER 2000

1 SCOPE OF WORK

The Queensland Competition Authority (QCA) will shortly assume responsibility for regulating Queensland's two electricity distribution businesses (DBs), ENERGEX Ltd and Ergon Energy. As part of this process and as an input to the setting of price controls, the QCA engaged Tasman Asia Pacific (Tasman) in association with the Pacific Economics Group (PEG) to benchmark the DBs' operations and maintenance expenditure against expenditure incurred by similar utilities in Australia and comparable overseas utilities. An analysis of the reliability of supply has also been undertaken. This overview is based on the findings of the detailed analyses which are documented in four reports comprising:

- *Benchmarking Comparison of ENERGEX Ltd and 9 other Australian Electricity Distributors*, Consultancy report prepared for the Queensland Competition Authority, Tasman Asia Pacific, 22 November 2000;
- *Benchmarking Comparison of Ergon Energy and 9 other Australian Electricity Distributors*, Consultancy report prepared for the Queensland Competition Authority, Tasman Asia Pacific, 22 November 2000;
- *ENERGEX Operating and Maintenance Cost Performance: Results from International Benchmarking*, report prepared for the Queensland Competition Authority, Pacific Economics Group, November 2000; and
- *Ergon Energy Operating and Maintenance Cost Performance: Results from International Benchmarking*, report prepared for the Queensland Competition Authority, Pacific Economics Group, November 2000.

The following section summarises the findings of the studies. The implications of the findings are outlined in section 3. This is followed by a discussion of the time that should be allowed for the business to adjust to best practice. Section 5 lists the recommendations.

2 FINDINGS

2.1 Unit operating and maintenance costs

To complete the assignment two streams of work were undertaken. The first stream of work benchmarked the DBs' operations and maintenance expenditure in 1999 against the expenditure incurred by nine other Australian DBs.

A comparison of the benchmarking data indicated that one of the Queensland DBs has a significantly different operating environment to the other nine Australian distributors. Ergon Energy has a network consisting of over 138,000 circuit kilometres in a service area of over one million square kilometres. These characteristics resulted in Ergon having a network density of less than half that of the next least dense distributor and less than ten per cent that of its fellow Queensland distributor, ENERGEX.

To make reliable cost comparisons between the DBs and the other nine Australian distributors we needed to develop a methodology that adjusted measured cost for the operating environment the DBs encounter. Thus, in the first stream of work a comprehensive measure of the output generated by each DB — or an output quantity index — was developed. Four outputs were specified for the output quantity index: throughput (measured by gigawatt hours of energy delivered), network length (measured by MVA kilometres), the number of customers served and reliability (measured by SAIDI).

The four outputs were aggregated into a comprehensive output index in the following manner. The reliability output measure was treated as a negative output because a higher number of minutes off supply equates to a less reliable system. It was allocated a value based on the retail price of forgone energy multiplied by a penalty value of 100. The remaining three outputs were weighted together using a system of weights derived from a simple econometric cost function that was estimated using our Australian DB sample data. The weight that applied to any given output was equal to its coefficient in this cost function divided by the sum of the coefficients for all three outputs in the cost function. Using this approach, the weights were around 50 per cent for throughput, 23 per cent for network length and 27 per cent for the number of customers.

Dividing operations and maintenance (O&M) cost by this output quantity index yields a partial factor productivity (PFP) index. This PFP measure for O&M produces much more stable and reliable comparisons among the DBs' O&M cost performance. As shown in Table 1, if the PFP for O&M is used, the Queensland DBs are amongst Australia's best performers in terms of unit O&M expenditure. In contrast, the DBs appear to be less efficient if more traditional measures of distribution output are used to normalise O&M costs, eg operations and maintenance expenditure per GWh. ENERGEX does relatively well on the customer based measure while Ergon does well on the network length based measure.

Table 1: **Four measures of unit operations and maintenance costs**

	Ergon		ENERGEX		Average
	<i>Measure</i>	<i>Rank</i>	<i>Measure</i>	<i>Rank</i>	
Operations and maintenance expenditure per network kilometre	\$1,092	2	\$3,635	6	\$3,712
Operations and maintenance expenditure per Gwh	\$13,232	8	\$9,929	4	\$11,406
Operations and maintenance expenditure per customer	\$278	10	\$149	2	176
Operations and maintenance expenditure per unit output index (Ergon = 1.0)	1.00	5	0.85	2	1.18

The more comprehensive measure of distribution output used in this study provides an objective and scientific way of combining the different dimensions of a DB's output into one measure while going as far as is possible towards adjusting for operating environment differences using Australian data. The comprehensive output index is judged to be the most robust measure of output and it is recommended that this measure be adopted for the calculation of unit operations and maintenance expenditures.

Using this measure it can be seen from Table 1 that ENERGEX had the second lowest measured unit operations and maintenance expenditure and Ergon Energy ranked fifth on this measure. However, the DB with the lowest observed unit O&M cost has a different structure to the other nine DBs and has had to make many assumptions to present data on a similar basis to the other DBs. Consequently, we adopt the conservative policy of taking the second lowest score as a reasonable estimate of Australian best practice. This makes ENERGEX Australian best practice on unit O&M costs. It is the least dense of the urban distributors while the third and fourth placed DBs are the two rural DBs with the lowest densities (in terms of customers per network kilometre) after Ergon. Consequently, achieving a unit O&M cost similar to the second placed DB is a reasonable target for Ergon to meet Australian best practice. This would involve a reduction in Ergon's unit O&M costs of 15 per cent. It should be noted that the reduction in unit O&M costs could be achieved by output remaining unchanged and O&M costs being reduced by 15 per cent, by O&M costs remaining unchanged and output increasing by 17.5 per cent or by improving reliability performance.

However, it is important to recognise that best practice in the use of one input can be achieved through greater use of other inputs such as capital leading, in some cases, to a worsening of overall productivity. Combining a comprehensive output measure with a comprehensive input measure also allows us to calculate total factor productivity (TFP) — a key measure of overall

efficiency comparing total outputs per unit of total inputs. Excluding the top performer on this measure which has quite different characteristics to the rest of the sample and taking an average of the second and third ranked DBs as Australian best practice (one of which has a substantial element of remote supply and the other of which is predominantly urban), ENERGEX is around 7.5 per cent behind Australian best practice and Ergon Energy is around 22 per cent behind Australian best practice.

This result may suggest that some of the superior operations and maintenance cost performance achieved by the DBs may have been achieved through the use of above average levels of capital. However, such a conclusion could not be justified on the basis of the analysis so far conducted. In addition we note that the QCA has also undertaken a separate analysis of the capital requirements of the DBs. Thus, from a rate setting perspective, there is insufficient information to adjust the measured differences in the PFP for operations and maintenance to reflect differences in the DB's TFP.

We therefore conclude that ENERGEX would require no adjustment of its operations and maintenance costs to reflect best practice in Australia and that Ergon Energy would need to lower unit operations and maintenance costs by 15 per cent to achieve Australian best practice.

Australian best practice may, however, be below international best practice. To examine this issue PEG undertook a statistical benchmarking exercise. Such an exercise was made possible by the extensive databases on the electricity industry in the United States. These databases are available as a result of the requirement for electric utilities to complete the Federal Energy Regulatory Commission (FERC) form.

PEG has developed a high quality database based on the FERC data. Of 187 companies that filed their FERC forms electronically, 103 were judged to have robust data. Data for the period 1996 to 1998 inclusive were employed to estimate an electricity distribution cost function and equations which explain the share in total cost of each input. The model included three inputs: capital, labour, and other operations and maintenance costs. Only two of the three share equations need to be estimated as the structure of the omitted equation can be derived from the results for the included equations and the cost function. Prior to estimating the cost function, the data for Ergon, ENERGEX and the United States companies were made as comparable as possible with regard to the definition of O&M cost.

The major determinants of cost were found to be the amount of work performed by the company, input prices paid by the companies, the amount of distribution line miles and the percentage of sales to non-industrial customers. The statistical properties of the estimated cost function were judged to be sound. The parameter estimates were in general statistically significant and plausible in size and magnitude.

The estimated cost function was used to evaluate the DBs' O&M costs given the input prices that they face and the environment they operate in. This was done through a three-step procedure. First, data on the prices paid by the DBs for their inputs and data on customer numbers, delivery volumes, distribution line miles and the per cent of deliveries to non-industrial customers were fed into the cost model and a point estimate for the DBs' total costs was derived. Next, relevant data for the DB was inputted into the estimated cost share equations and the optimal share of each input in total costs was derived for the DB. The predicted total cost for power distribution was then multiplied by the optimal cost shares to calculate the predicted cost of each input used by the businesses. These costs for O&M inputs were then compared to the actual O&M costs incurred by the businesses.

When these calculations were undertaken, Ergon's predicted operations and maintenance cost was 8.71 per cent below its actual cost. In the case of ENERGEX, the predicted cost was 1.97 per cent above its actual operations and maintenance cost. Interpreted simply, these results imply that ENERGEX's operations and maintenance costs are two per cent below the operations and maintenance costs observed for the average utility in the United States operating under the same business conditions. Ergon's operations and maintenance costs are 8.71 per cent above the average utility in the United States operating under the same business conditions. These differences were not found to be significantly different from zero. It is noteworthy, however, that the O&M cost performance of Ergon and Energex was well below the performance levels exhibited by the top quartile of performers in the US sample.

After taking account of differences in operating environments, PEG's results imply that the estimated difference in O&M cost performance between Ergon and ENERGEX is around 11 per cent (*i.e.* with ENERGEX at 2 per cent below predicted cost and Ergon at 8.7 per cent above predicted cost, the performance gap between the companies is estimated to be 10.7 per cent). This is similar to the figure of 15 per cent obtained in the Tasman study, and the common picture emerging from the different methodologies and databases provides substantial confidence in the results. The slightly larger gap in the Tasman study is likely to be explained by the inclusion of reliability as a negative output in the Tasman model. As Ergon has relatively worse reliability than ENERGEX, this will tend to reduce its comprehensive output and increase its unit O&M costs relative to the PEG study. The PEG study also adjusts for more operating environment differences than the Tasman study, and this may further reduce the estimated gap.

2.2 Reliability

Tasman assessed the reliability of the Queensland DBs against the other 8 Australian DBs in the Tasman database. This assessment showed that Ergon had the worst overall reliability performance using the SAIFI (average number of interruptions per customer) and SAIDI (average number of minutes of interruptions per customer) measures and the fourth worst

reliability using the CAIDI (average duration of interruption) measure. ENERGEX had midfield reliability performance overall ranking fifth out of 10 on each of SAIFI, SAIDI and CAIDI. However, ENERGEX was generally the worst reliability performer of the five predominantly urban DBs.

PEG assessed the DB's reliability relative to the US sample and relative to a selected group of utilities which were assessed to operate in broadly similar circumstances. The SAIFI and SAIDI reliability measures were used.

The analysis is summarised in Table 2.

Table 2: The relative reliability performance of Ergon Energy and ENERGEX.

	<i>Full sample</i>	<i>Ergon^a</i>	<i>US companies most similar to Ergon</i>	<i>ENERGEX^a</i>	<i>US companies most similar to ENERGEX</i>
SAIFI	1.3	3.36	1.99	1.99	1.27
SAIDI	125.1	307.10	152.83	169.4	92.71

a Average of 1998 and 1999.

PEG concluded that, based on the comparison, Ergon and ENERGEX exhibit relatively poor reliability. PEG, however, recognised the limitations of its analysis and in particular a need to incorporate service reliability into the statistical benchmarking methodology. PEG did, however, conclude that there was scope for the DB's to improve reliability.

One way for ENERGEX and Ergon to improve their reliability performance is through a formal service quality incentive mechanism. Under this approach, each company's SAIFI and SAIDI performance would be compared annually to a benchmark performance level. A reasonable benchmark in the initial price control could be each company's historical performance on that indicator. Deadbands could also be established around this benchmark. A deadband refers to a zone around the benchmark where a company is neither penalized nor rewarded depending on its reliability performance.

When performance is outside of the deadband, each company would be automatically penalized or rewarded. Rewards would result when either SAIFI or SAIDI is below the lower band. Penalties would occur if SAIFI or SAIDI is above the upper band.

The amount of penalties or rewards for a given change in performance should be linked to customer value. This issue deserves further research in Queensland. However, there are a number of studies of customer outage costs from power interruptions which can be used as the basis for these penalty/reward rates. PEG has done a considerable amount of work in developing service quality incentive plans that use published outage cost research as the basis for service reliability penalty and rewards in North America. Further research is required to derive the appropriate size of incentive payments given Australian conditions.

3 IMPLICATIONS

Our results imply that both Ergon and ENERGEX would need to make significant productivity improvements to achieve an operations and maintenance performance that puts them into the top quartile of the PEG analysis.

Such an increase in performance can be thought of as consisting of two principal components:

- Movement to Australian “best practice”; and
- Movement from Australian “best practice” to United States “best practice.”

We assume, based on the Tasman analysis of Australian PFP measures for operations and maintenance inputs, that ENERGEX has already achieved Australian best practice but that Ergon would need to lower per unit operations and maintenance costs by up to 15 per cent to achieve Australian best practice operations and maintenance costs. Adopting a conservative approach again, we assume that this reduction is around 11 per cent as estimated in the PEG analysis.

A move to United States best practice, as indicated by the largest (negative) difference between actual and predicted O&M costs observed in the PEG analysis, would involve a further substantial reduction in operations and maintenance costs compared to Australian best practice O&M costs. However, even in the best benchmarking studies, there are considerable uncertainties about what constitutes an achievable efficiency “frontier”. We therefore recommend that efficiency targets be relatively conservative and not attempt to move utility costs all the way towards what is believed to be a “frontier” standard.

Given the observed US O&M performance levels, we believe that an efficiency target at the lower end of the top quartile of US performers is reasonable and achievable. The PEG analysis indicates that the top quartile O&M performance level for the US sample begins at about 19 below predicted costs. That is, within the US sample, the O&M costs for the top quartile of performers are all 19% or more below their predicted O&M costs given the business conditions that they face. A utility that attains an O&M performance level at the lower end of the top quartile would therefore have O&M costs 19% below its predicted costs.

This figure can be used to determine how much ENERGEX and Ergon would have to reduce O&M costs to attain this performance level. As Ergon’s actual O&M costs are currently 8.7 above their predicted value, its total improvement would be 27.7 per cent (8.7 +19.0). Similarly, ENERGEX’s total improvement would be 17 per cent (-1.97 +19).

Efficiency targets could incorporate factors that reflect anticipated improvements in unit O&M costs over the period of price regulation. Such gains could flow from at least two other sources. One is the achievement of further economies of scale as the DB expands its output. A second is additional technological advances.

At this stage there is very little data available to assess either the scope for achieving further economies of scale or improvements in best practice over time. We are currently surveying industry experts to provide insights into the scope for technological advance in electricity distribution. Only one survey had been returned at the time of drafting. However, discussions with industry experts suggested that while there is much scope still to implement current best practice (ie move towards the current frontier), changes in best practice (ie movements in the frontier itself) are likely to be quite modest over the next 5 years. At this point in time there is inadequate information available to form reasonable quantitative estimates of the magnitude of these effects. Further research on these factors should be a high priority during the first regulatory period.

In light of the current lack of information on other factors that may influence the trend growth in unit O&M costs in Queensland, we therefore recommend that the operations and maintenance targets for the DBs not include any additional factors. Once the current regulatory structure in Queensland has become more mature and the availability of key data has improved, the QCA should consider including a factor for improvements in best practice and achieving economies of scale. These factors can be incorporated in price controls to take effect in the second regulatory period. The current review should concentrate on moving towards the elimination of existing static efficiency gaps.

4 A TIME FRAME FOR ADJUSTMENT

It is recommended that a period of ten years be set for the DBs to achieve the required improvements in efficiency. It is further recommended that yearly targets equal to one tenth of the total target be set. That is, that ENERGEX be required to reduce unit operations and maintenance costs by 1.7 per cent per year (in real terms) over the regulatory period and Ergon be required to reduce unit operations and maintenance costs by 2.77 per cent per year (in real terms) over the regulatory period.

Our recommended time frame for achieving the O&M cost targets is based largely on judgment. The rationale is that, in the first regulatory period, the DBs can begin on a path that moves them towards achieving the efficiency goals. The first regulatory review can evaluate progress towards achieving these goals, as well as industry changes that have affected unit O&M costs.

5. RECOMMENDATIONS

The following recommendations are made:

- ENGERGEX be required to reduce real per unit operating and maintenance expenditure by 1.7 per cent per year over the regulatory period;
- Ergon Energy be required to reduce real per unit operating and maintenance expenditure by 2.77 per cent per year over the regulatory period;
- Unit operations and maintenance costs be calculated by dividing real operations and maintenance expenditure by a measure of output formed by weighting together throughput, customer numbers and circuit kilometres where the weights are 0.5, 0.27 and 0.23 respectively; and
- Consideration be given to the introduction of a mechanism to encourage the DBs to improve reliability of service delivery (see section 2.2).