



**Electricity Distribution Businesses'
Financial and Service Quality
Performance 2002-03**

March 2004

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1. INTRODUCTION AND SUMMARY

In May 2001, the Authority published its Final Determination on the Regulation of Electricity Distribution¹. As part of the Final Determination, the Authority required the Queensland Distribution Network Service Providers (DNSPs) to provide annual information on financial and service quality performance.

The financial information is required to be submitted in accordance with the Authority's *Electricity Distribution: Regulatory Accounting and Information Guidelines* and the DNSPs' approved Cost Allocation Guidelines. This Report provides an assessment of the financial performance of the two Queensland DNSPs for 2002-03, including a comparison with the financial forecasts that were included in the Authority's Final Determination and comparisons with the past financial performance of the DNSPs. The structure and content of the report will evolve as information is accumulated and, over time, the Authority will be able to provide more in-depth commentary and analysis of the information presented.

The service quality information is required to be submitted in accordance with the Authority's *Electricity Distribution: Service Quality Reporting Guidelines*. The Guidelines require DNSPs to provide data on specific service quality measures on a quarterly and annual basis. While the DNSPs commenced reporting with the December quarter 2001 reports, the Authority only commenced publicly releasing the reports with the September quarter 2002 reports due to concerns about the robustness of the data. As a result, 2002-03 is the only year for which the Authority has service quality data which can be made public. This report draws on data from both the annual and quarterly reports for 2002-03. As further data is accumulated, the performance of each DNSP will be subject to more in-depth assessment.

1.1 General Operating Background

There are currently two DNSPs operating in Queensland, Energex and Ergon Energy². Both distribution entities are owned by the Queensland Government and have legally separate but subsidiary retailing operations.

Network characteristics

The distribution entities have considerably different network characteristics. Energex operates a largely urban network with relatively high customer density in southeast Queensland, whereas Ergon Energy operates a geographically dispersed network with low customer density that covers much of the remainder of the State. Table 1 provides some key network descriptors that illustrate how different the distributors' networks are. A key difference is customer density. Specifically, while there are more than 45 customers per square kilometre in Energex's network service area, Ergon Energy has just one customer every three square kilometres of network service area.

These differences in network characteristics are an important determinant of the service quality performance of each distributor, particularly the reliability of their respective networks.

¹ The cost of electricity distribution represents approximately 40 per cent of an average residential customer's final bill, with the remainder consisting of costs associated with generation, high-voltage transmission and retailing of electricity.

² Country Energy (NSW) operates a franchise network on the Queensland/New South Wales border extending into Queensland.

Table 1: Network descriptors for Energex and Ergon Energy - 2002-03

Network descriptor	Energex	Ergon Energy
Network service area (sq km)	25,264	1,698,100
Number of customers ¹	1,129,940	584,878
Energy delivered (GWh) ¹	17,833	12,461
Energy delivered per customer (MWh)	15.8	21.3
Kilometres of line	44,751	138,330 ²
Customers per km of line	25.2	4.2
Maximum demand of network (MVA)	3,556	2,180
Number of distribution transformers	37,666	78,362
Asset utilisation (%) ³	39.2	26.4
Distribution losses (%)	5.7	6.0

¹ These values are reported in the distributors' regulatory accounts and differ slightly to the values reported for the same measures in the distributors' service quality reports due to technical differences in the way they are defined.

² For year ending 30 June 2002. Ergon Energy was unable to provide updated data for 2002-03.

³ Sub-transmission transformer utilisation factor. Electricity throughput (MWh) expressed as a percentage of sub-transformer capacity (MVA) multiplied by the number of hours per year.

1.2 Energex

Summary of Energex Financial Performance

Overall, the financial performance of Energex for 2002-03 is mixed compared with the forecasts underlying the Final Determination (see Table 2). Energex over-recovered their allowable revenue (including capital contributions) by \$8.9 million. As a result, only minor adjustments to Energex's allowable revenue will be required in 2004-05 to return the small over-recovery to consumers (the 2002-03 data was not available in time for adjustments to be made to 2003-04 allowable revenue). As forecast, Energex's revenue in 2002-03 was higher than for the previous year.

Table 2: Energex financial performance - 2002-03

	Actual 2001-02 (\$ mill)	Actual 2002-03 (\$ mill)	Forecast1 2002-03 (\$ mill)	Variance from forecast 2002-03 (\$ mill)	(%)
Allowable revenue					
Distribution use of system charges	468.4	505.1	497.0	8.1	1.6
Capital contributions	23.9	24.8	24.0	0.8	3.3
Operating and maintenance expenditure	130.2	121.0	168.9	(47.9)	(28.4)
Capital expenditure	270.6	281.7	257.9	23.8	9.2

¹ Adjusted where necessary

As part of the Final Determination, the Authority forecast the level of operating costs and capital expenditure required to deliver prescribed distribution services for each year of the regulatory period for each DNSP. While forecasts were provided for each year of the regulatory period, actual annual operating and capital expenditure are likely to vary from those forecasts in response to a range of external circumstances not foreseen at the time.

During 2002-03, Energex recorded operating expenditure of \$121 million, substantially below the \$168.9 million forecast in the Final Determination and also below that recorded in 2001-02. Energex attribute this under-spend to a number of factors including the continuation of a superannuation contribution holiday following an actuarial review and the capitalisation of previously expensed costs (pole replacements and under-height services). In addition, Energex indicated that \$24.9 million of the \$47.9 million under-spend during 2002-03 was due to efficiency savings. This follows reported efficiencies of \$14.3 million (out of a total under-spend of \$31.5m) in 2001-02. The Authority is yet to consider the substance of these claims.

Energex recorded higher-than-forecast demand related expenditure reflecting higher-than-forecast growth in customer demand. While electricity sales increased by 3.6 per cent, maximum (peak) demand increased by around 7 per cent over the previous year. In addition, Energex also recorded significantly higher-than-forecast asset replacement expenditure. This was primarily due to the capitalisation of previously expensed costs. Energex reduced other categories of capital expenditure during the year to accommodate the increased demand related and asset replacement expenditure.

Summary of Energex Service Quality Performance

During 2002-03, Energex customers, on average, experienced 2.09 distribution-related interruptions. With each interruption lasting an average of 90.0 minutes, customers, on average, were left without power for a total of 188.3 minutes over the year. As shown in Table 3, the number and duration of interruptions have increased from 1.92 and 169.9 minutes respectively since the first quarter of 2002-03, indicating a deterioration in the reliability of electricity supply for 2002-03 compared to the year ending September 2002³.

The total number of quality of supply complaints received by Energex decreased over 2002-03, from 768 during the September quarter of 2002 to 596 in the June quarter of 2003.

Energex's performance against a range of customer service measures was mixed over the course of 2002-03. The length of time that Energex customers had to wait to speak to an operator when calling the call centre fell significantly, from 3 minutes and 3 seconds during the September quarter 2002 to 59 seconds in the June quarter 2003. The percentage of calls that were abandoned by callers declined steadily, down from 17.0 per cent in the September quarter 2002 to 7.3 per cent in the June quarter 2003. The length of time that customers had to wait for a new connection to the network varied little over 2002-03, at just over 4 days. The proportion of total new supply connections that Energex failed to make by the agreed date was 3.7 per cent during the first and last quarters of 2002-03, but peaked at 7 per cent during the December quarter 2002.

³ The quarterly reliability measures are based on 12 month rolling averages. As a result, reliability data for the June quarter in 2003 reflects reliability performance during 2002-03. Similarly, reliability data for the September quarter in 2002 reflects reliability performance during the previous 12 months.

Table 3: Summary of Energex service quality performance - 2002-03

	September 2002	December 2002	March 2003	June 2003
Average number of interruptions per customer per year – distribution-related (SAIFI)	1.92	2.01	2.07	2.09
Average duration of each interruption per year – distribution-related (CAIDI) - minutes	88.5	93.3	91.0	90.0
Duration of all interruptions per customer per year – distribution-related (SAIDI) – minutes	169.9	187.1	188.4	188.3
Total number of quality of supply complaints	768	672	696	596
Average waiting time to speak to an operator - seconds	183	105	98	59
Percentage of calls abandoned by customers	17.0	14.3	11.0	7.3
Average time taken for new connections - days	4.10	4.15	4.09	4.05
Percentage of new connections not made by the agreed date	3.7	7.0	5.0	3.7

1.3 Ergon Energy

Summary of Ergon Energy Financial Performance

Overall, the financial performance of Ergon Energy for 2002-03 is mixed compared with the forecasts underlying the Final Determination (see Table 4). Ergon Energy's actual revenue was relatively close to that forecast by the Authority, with an over-recovery of \$2.25 million. As a result, only minor adjustments to Ergon Energy's allowable revenue will be required in 2004-05 to return the small over-recovery to consumers (the 2002-03 data was not available in time for adjustments to be made to 2003-04 allowable revenue). As forecast, Ergon Energy's revenue in 2002-03 was higher than for the previous year.

Table 4: Ergon Energy financial performance - 2002-03

	Actual 2001-02 (\$ mill)	Actual 2002-03 (\$ mill)	Forecast ¹ 2002-03 (\$ mill)	Variance from forecast 2002-03	
				(\$ mill)	(%)
Allowable revenue					
Distribution use of system charges	443.9	475.5	476.05	(0.55)	(0.1)
Capital contributions	16.9	19.9	17.1	2.8	16.4
Operating and maintenance expenditure	135.0	159.0	154.6	4.4	2.8
Capital expenditure	235.0	312.8	234.0	78.8	33.7

¹ Adjusted where necessary

As part of the Final Determination, the Authority forecast the level of operating costs and capital expenditure required to deliver prescribed distribution services for each year of the regulatory period for each DNSP. While forecasts were provided for each year of the regulatory period, actual annual operating and capital expenditure are likely to vary from those forecasts in response to a range of external circumstances not foreseen at the time.

Following lower-than-forecast operating and maintenance expenditure in 2001-02 (of \$135.0m), Ergon Energy recorded an over-spend of \$4.4 million in 2002-03. After allowing for approved cost pass-throughs, the over-spend is reduced to \$2.75 million. This increase in operating and maintenance expenditure reflects a partial catch-up of the shortfall in expenditure in 2001-02 of \$15.9 million.

Capital expenditure was higher-than-forecast for Ergon Energy (\$78.8 million or 33.7 per cent). Ergon Energy recorded higher-than-forecast demand related expenditure reflecting higher-than-forecast growth in customer demand. While Ergon Energy's volume of electricity sales only increased by 1 per cent, maximum (peak) demand increased by around 8.5 per cent over the previous year. In addition, Ergon Energy recorded significantly higher-than-forecast asset replacement expenditure. This reflected the continuation of their Asset Inspection and Defect Management (AIDM) program introduced in 2001-02. Ergon Energy reduced other categories of capital expenditure during the year to accommodate the increased demand related and asset replacement expenditure.

Summary of Ergon Energy Service Quality Performance

During 2002-03, Ergon Energy customers, on average, experienced 4.50 distribution-related interruptions. With each interruption lasting an average of 109.8 minutes, customers, on average, were left without power for a total of 494.8 minutes over the year. As shown in Table 5, the number and duration of interruptions have increased from 4.34 and 451.0 minutes respectively since the first quarter of 2002-03, indicating a deterioration in the reliability of electricity supply for 2002-03 compared to the year ending September 2002.

The total number of quality of supply complaints received by Ergon Energy increased over the first two quarters of 2002-03, from 585 during the September quarter of 2002 to 761 in the December quarter of 2003, before falling to 589 in the June quarter 2003.

Ergon Energy's performance against a range of customer service measures was also mixed over the course of 2002-03. The length of time that Ergon Energy customers had to wait to speak to an operator when calling the call centre increased from 27 seconds during the September quarter 2002 to 88 seconds in the June quarter 2003. The percentage of calls that were abandoned by callers increased during 2002-03, up from 2.7 per cent in the September quarter 2002 to 7.1 per cent in the June quarter 2003. The length of time that customers had to wait for a new connection to the network decreased significantly, from 11.8 days in the September quarter 2002 to 3.7 days in the June quarter 2003. The proportion of total new supply connections that Ergon Energy failed to make by the agreed date decreased from 5.4 per cent to 4.5 per cent over the course of 2002-03 after rising to 7.0 per cent in the March quarter 2003.

Table 5: Ergon Energy service quality performance - 2002-03

	September 2002	December 2002	March 2003	June 2003
Average number of interruptions per customer per year – distribution-related (SAIFI)	4.34	4.67	4.40	4.50
Average duration of each interruption per year – distribution-related (CAIDI) - minutes	104.0	107.0	109.0	109.8
Duration of all interruptions per customer per year – distribution-related (SAIDI) – minutes	451.0	499.9	484.0	494.8
Total number of quality of supply complaints	585	761	759	589
Average waiting time to speak to an operator - seconds	27	53	48	88
Percentage of calls abandoned by customers	2.7	5.7	4.8	7.1
Average time taken for new connections - days	11.8	4.5	4.2	3.7
Percentage of new connections not made by the agreed date	5.4	6.1	7.0	4.5

2. ENERGEX

2.1 Customer Profile

In 2002-03, all customers with an average consumption of more than 200MWh a year, approximately 7,000 customers, were eligible to become contestable. The contestable customer groups of Energex consist of: individually calculated customers (those customers whose electricity consumption is sufficiently large to warrant individually calculated prices); connection asset customers (those customers whose electricity consumption is sufficient to warrant individually calculated connection charges but their remaining charges are averaged); and standard asset customers (customers who pay averaged charges). The non-contestable customer group incorporates all franchise customers (customers who access a franchise price). The number of customers in each category and the corresponding units of electricity sold to each is presented below.

Table 6: Energex customer numbers and units sold - 2002-03

Customer type	Customers		Units sold		Units sold per customer	
	Number	Percentage change from previous year	MWh	Percentage change from previous year	MWh/customer	Percentage change from previous year
Contestable customers						
Individually calculated customers	22	0	1,347,734	2.4	61,260.6	2.4
Connection asset customers	317	5.3	3,184,051	4.5	10,044.3	(0.8)
Standard asset customers	2,824	20.4	2,221,603	28.5	786.7	6.7
Non-contestable customers						
Franchise customers ¹	1,126,775	2.2	11,076,924	(0.3)	9.8	(2.8)
Embedded generators	2	100.0	2,993	11.1	1,496.5	(44.5)
Total	1,129,940	2.2	17,833,305	3.6	15.8	1.3

¹ This category includes some potentially contestable customers which have not elected to enter the market.

The number of Energex customers increased by 2.2 per cent from the previous year, while energy sales increased 3.6 per cent during the year following a 5.3 per cent increase in 2001-02. This compares with forecast average growth in energy sales of 4.2 per cent per annum over the regulatory period. The Standard Asset Customer category experienced the strongest growth in 2002-03 with an increase in customers of 20.4 per cent and an increase in energy sales of 28.5 per cent. Energex could not identify any single factor to explain this growth but suggested that increased retailer activity designed to entice customers into the contestable market and an increased number of customers reaching the 200 MWh contestability threshold were contributing factors.

2.2 Revenue and Expenditure

This section summarises the financial performance of the revenue cap regulated business segment of Energex.⁴ The information is for the year ended 30 June 2003. The data used in the analysis has been drawn mainly from Energex's audited Regulatory Accounting Statements.

⁴ In addition to the revenue cap regulated activities, there were also a small number of distribution services regulated by the Authority in 2002-03 on a cost plus 5 per cent margin basis. Revenue from these activities amounted to around \$14.2 million (2.7 per cent of total revenue).

These accounts were submitted in accordance with the Authority’s *Electricity Distribution: Regulatory Accounting and Information Guidelines*.

The overall financial performance is driven by the net effect of Energex’s results in three areas: revenue; operating and maintenance expenditure; and capital expenditure. Energex’s reported results on these components compared with the corresponding forecasts that were included in the Final Determination and the previous year’s actual data are presented below. Detailed financial data tables for Energex are provided at Appendix A.

Revenue

Under/Over Recovery of Distribution Revenue

In the Final Determination, the Authority set a maximum revenue cap for each of the four years of the initial regulatory period for Energex. The maximum revenue cap allows Energex to earn a return on assets, plus an allowance for depreciation and operating expenditure incurred in the delivery of prescribed distribution services. The Final Determination also acknowledged the possibility of within-period adjustment to revenue caps to allow for agreed cost pass-throughs or corrections to the underlying revenue cap calculations. A cost pass-through allows the distributor to increase (decrease) its revenue cap in response to an increase (decrease) in a cost that was unforeseen at the time of the Final Determination, is typically beyond its control and is readily observable.

During 2002-03 cost pass-through was permitted for costs associated with the introduction of the Electrical Safety Office. Under legislation introduced by the Queensland Government, a number of functions previously undertaken by Energex were transferred to the Electrical Safety Office within the Department of Industrial Relations. The Electrical Safety Office is funded via a levy on both distributors.

The Authority reviewed Energex’s application for pass-through of costs associated with the Electrical Safety Office and approved an additional \$2.89 million of revenue to be raised by Energex in 2002-03.

As part of the Final Determination, the Authority stated its intention to use an “unders and overs” account applying to each DNSP to ensure compliance with the annual revenue caps set in the Determination. The unders and overs process compares actual revenue earned in the year against the annual revenue cap for that year as determined by the Authority.

Table 7: Energex DUOS revenue – 2002-03

	\$ million (nominal)
Actual Revenue earned during 2002-03 ¹	
Revenue from distribution tariffs	505.1
Revenue from capital contributions	24.8
less Allowable annual revenue (updated where necessary) ²	521.0
<i>equals</i> Over/(under) recovery for 2002-03	8.9

¹ Does not include revenue earned from the use of regulated assets by non-regulated business segments.

² Includes distribution tariff revenue, revenue from capital contributions, and the revenue impact of an adjustment to correct for errors in the asset base.

Table 7 indicates that Energex over-recovered its allowed revenue by \$8.9 million (1.7 per cent). As per the Authority’s Final Determination, an over-recovery balance of less than 2 per cent requires the distributor to clear the balance of its unders and overs account during the

subsequent (2004-05) pricing period.⁵ Accordingly, the revenue over-recovery by Energex during 2002-03 will be rolled-forward and reflected in its allowable revenue for 2004-05 to be returned to all customer classes through 2004-05 distribution prices.

Under/Over Recovery of Transmission Use of System (TUOS) Charges

TUOS charges are calculated by DNSPs each year to pass-through to distribution customers the cost levied by Powerlink for the use of the transmission system.⁶ Electricity transmission charges are regulated by the Australian Competition and Consumer Commission (ACCC) and paid to Powerlink by DNSPs on behalf of end-customers. The Authority approves TUOS charges to be levied by the distributors that are intended to allow them to recover the TUOS charges they have paid to Powerlink. In approving the (DNSP's) TUOS charges, the Authority's main aim is to ensure that these charges reflect, as closely as possible, the structure of Powerlink's charges. Any difference between TUOS revenue recovered by DNSPs from customers and the charges they paid to Powerlink is recouped from/returned to customers through future (DNSP) TUOS charges.

Table 8: Energex TUOS unders and overs account – 2002-03¹

	\$ million (nominal)
TUOS charged by Powerlink	159.0
<i>less</i> actual TUOS revenue earned during 2002-03	160.0
<i>equals</i> Over/(under) recovery for 2002-03	1.0

¹ Numbers are rounded.

Table 8 indicates that Energex's customers were charged \$1.0 million more than cost during 2002-03 for transmission services. Accordingly, Energex will be required to return this over-recovery of TUOS charges to customers as part of its 2004-05 TUOS charges.

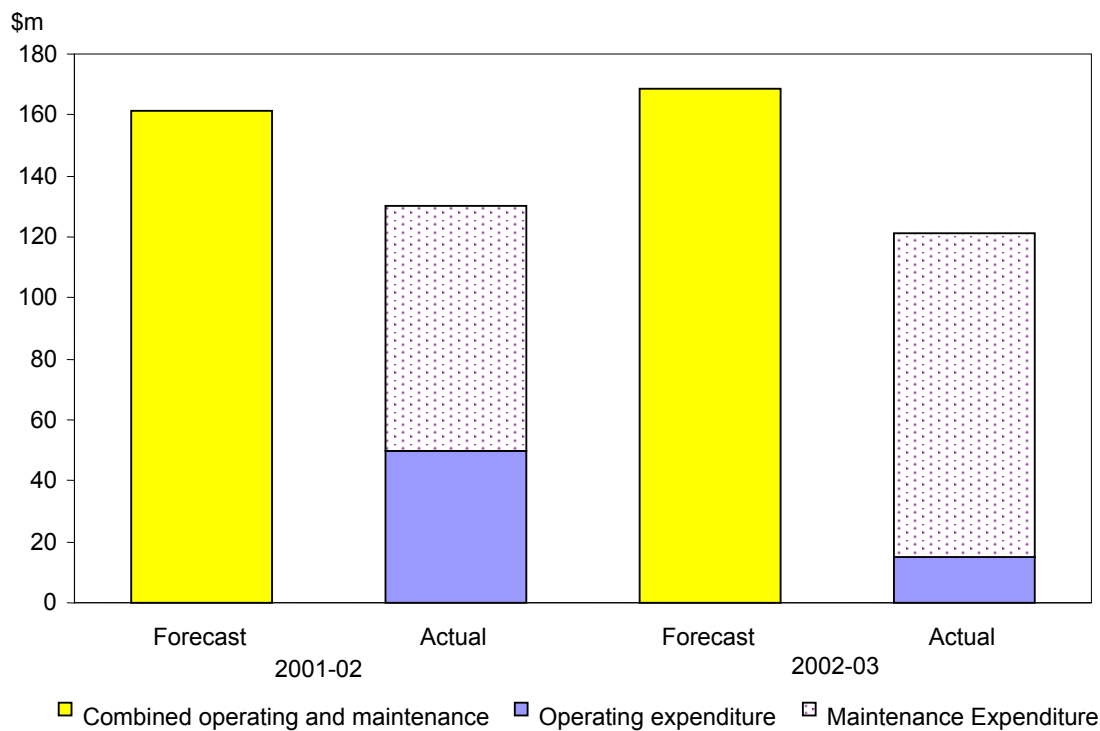
Operating and Maintenance Expenditure

The regulatory framework is designed to give the distribution businesses an incentive to increase their forecast return by improving their efficiency and hence reducing costs. To this end, the distributors retain the benefit of any efficiency gain for the remainder of the regulatory period (or longer if provision were made for carry-over between regulatory periods).

Figure 1 shows network operating and maintenance expenditure reported by Energex for 2001-02 and 2002-03, compared with the forecast operating and maintenance expenditure in the Final Determination.

⁵ Distribution prices for 2003-04 were required to be set in May 2003, before the receipt of the distributor's 2002-03 Regulatory Accounting Statements. This timing will always be the case meaning there will always be a 2 year lag between establishing an under/over recovery has occurred and its recoupment/return.

⁶ TUOS charges are separately identified from DUOS charges under the Queensland electricity distribution pricing regime.

Figure 1: Energex operating and maintenance expenditure – 2001-02 and 2002-03¹

¹ The Final Determination contains forecasts of combined operating and maintenance expenditure rather than separate forecasts for operating expenditure and maintenance expenditure.

Energex's operating and maintenance expenditure in both 2001-02 and 2002-03 was substantially below forecast. Energex's operating and maintenance expenditure of \$121.0 million in 2002-03 was \$47.9 million (28.4 per cent) lower than forecast and \$9.2 million (7.1 per cent) lower than in 2001-02. This decline was accounted for by a significant reduction in operating expenditure compared to the previous year (\$32.6 million or 68 per cent lower), while maintenance expenditure increased significantly (by \$23.4 million or 28.4 per cent higher). A portion of the decline in operating expenditure and increase in maintenance expenditure during 2002-03 may be due to Energex re-classifying a number of costs previously attributed to operating activities to maintenance activities. However, changes made by Energex during the year to the individual cost categories make comparisons between the two periods difficult.

Energex indicated that changes to their organisational structure and accounting systems mean that "costing information presented for regulatory purposes prior to July 2001 is not comparable with information presented subsequent to July 2001 and reflected in the 2002-03 accounts". Nevertheless, Energex did identify a number of reasons for the variance between forecast and actual operating and maintenance expenditure in 2002-03:

- superannuation contribution holiday following actuarial review (\$7.0 million);
- capitalisation of pole replacements, previously expensed (\$10.2 million);
- capitalisation of under-height services (\$1.5 million);
- efficiency savings:
 - shared services/holding company cost reductions via efficiencies and productivity improvements (\$3.3 million);

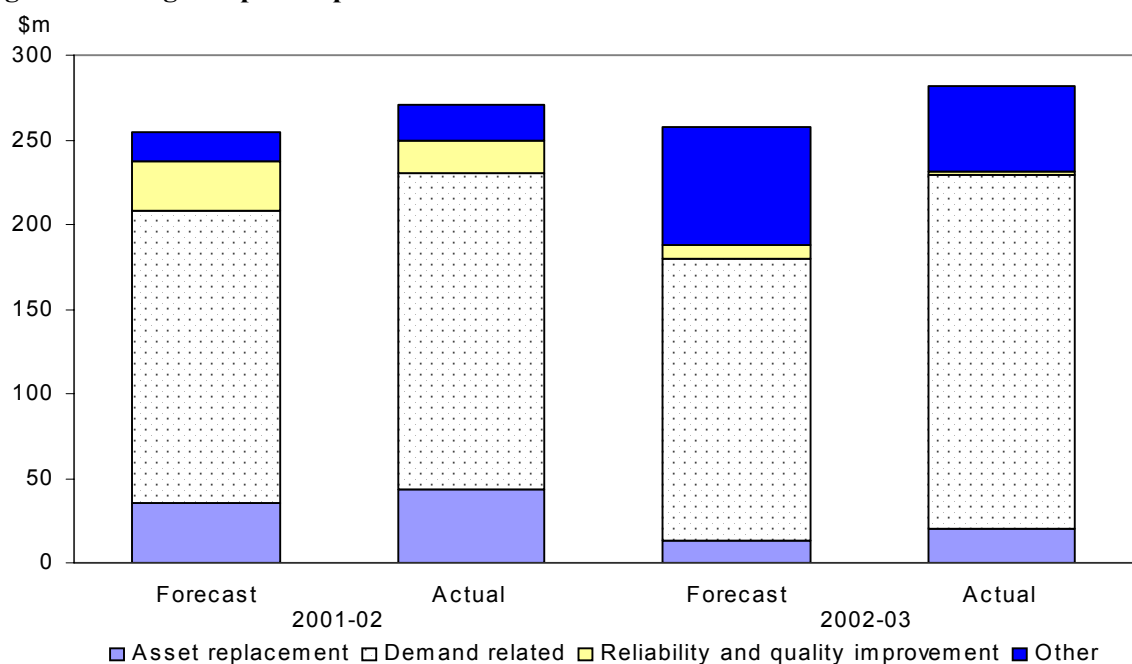
- shared services/holding company cost reductions via efficiencies from economies of scale (\$2.4 million);
- network efficiencies and productivity savings (\$19.2 million); and
- deferred expenditure (\$4.3 million)

The superannuation contribution holiday reflects past contributions in excess of current actuarial requirements and ceased on 1 July 2003. The capitalisation of pole replacements and under-height services will result in lower operating expenditure (and correspondingly higher capital expenditure) for the whole of the regulatory period as the costs are simply transferred from operating costs to capital costs. The Authority is yet to consider the substance of the \$24.9 million reported efficiency saving in operating expenditure. Energex have indicated that this represents the difference between the actual amount spent on particular operating activities during 2002-03 and that budgeted by Energex. The reported efficiency saving in 2002-03 follows similar savings of \$14.3 million reported in 2001-02.

Capital Expenditure

Figure 2 shows network capital expenditure (in aggregate and by purpose) reported by Energex for 2001-02 and 2002-03, compared with the forecast capital expenditure.

Figure 2: Energex capital expenditure – 2001-02 and 2002-03



Energex recorded capital expenditure of \$281.7 million during 2002-03, \$23.8 million (9.2 per cent) higher than forecast. However, this overall increase reflected a number of accounting adjustments, including the capitalisation of \$11.7 million of previously expensed costs and the capitalisation of \$15.7 million worth of non-system asset depreciation during the year. Adjusted for these changes, total capital expenditure was marginally below forecasts. This follows expenditure of \$270.6 million in the previous year which was also higher (\$16.3 million or 6.4 per cent) than forecast.

Demand related expenditure dominated Energex's capital expenditure during both 2001-02 and 2002-03. Energex indicated that the higher-than forecast demand related expenditure during

2002-03 (\$42.9 million or 25.8 per cent higher) was due to an increase in network demand (including new subdivisions) and was predominantly driven by air conditioning and new installations. Maximum network demand increased by around 7 per cent during 2002-03.

Asset replacement expenditure of \$20.4 million was 54.5 per cent higher-than-forecast largely due to the capitalisation of previously expensed pole replacement expenditure and under-height services expenditure as noted previously.

Energex indicated that reliability and “other” capital expenditure was reduced to accommodate the requirement for increased demand related expenditure. Within “other” capital expenditure, lower-than-forecast expenditure on non-system assets primarily reflects reduced expenditure on computer equipment and facilities than that previously budgeted by Energex.

2.3 Service Quality

This section summarises the service quality performance of the revenue cap regulated business segment of Energex. The information is for the year ended 30 June 2003 and, unless otherwise indicated, has been drawn from Energex’s quarterly and annual service quality reports for 2002-03. These reports were submitted in accordance with the Authority’s *Electricity Distribution: Service Quality Reporting Guidelines*. The Authority commenced posting the quarterly reports provided by the DNSPs on its website with the September quarter 2002 reports (released February 2003).

As data accumulates over time, Energex’s service quality performance will be able to be better assessed. As this is the first annual report to be released, the data should be treated with caution.

The service quality measures collected by the Authority are not intended to allow comparison of the two DNSPs with each other. This is because Energex and Ergon Energy operate in very different environments, as discussed in Chapter 1. As a result, it is to be expected that the distributors’ performance will vary significantly on a number of service quality measures.

The service quality measures that the DNSPs are required to report against fall into three broad groups – reliability measures, quality of supply measures and customer service measures.

Reliability measures provide information about interruptions to electricity supply. Interruptions can occur because of problems with generation, transmission or distribution. Distribution interruptions may be planned or unplanned, and unplanned interruptions will at times be due to events that are beyond the control of the DNSPs, such as severe storms. A DNSP’s performance is best indicated by the duration and frequency of planned and unplanned interruptions that are due to distribution network problems within the distributor’s control (although lengthy and frequent interruptions due to other influences may indicate a need for improved risk management measures on the part of the distributors). Reliability data for worst performing feeders highlights pockets of the network where customers experience relatively poor service quality.

Quality of supply measures are intended to indicate problems with the nature of electricity supply, such as low or high voltage levels, based on customers reporting symptoms that are typically associated with such problems. For example, low supply voltage would be evidenced by complaints relating to light dimming or motor starting problems.

Customer service measures provide information about how customers’ problems, enquiries and requests for services are handled by the DNSPs.

Reliability measures

During 2002-03, Energex customers, on average, experienced 2.38 interruptions as a result of interruptions arising from all segments of the electricity supply chain, including generation, transmission and distribution. With each interruption lasting an average of 95.5 minutes, customers, on average, were left without power for a total of 227.8 minutes over the year. Interruptions resulted in an estimated 7995 MWh of energy not supplied to customers over the year, which was equivalent to 0.045 per cent of total energy delivered to customers.

As shown in Table 9, the number and duration of interruptions have increased since the first quarter of 2002-03, indicating a deterioration in the reliability of electricity supply for 2002-03 compared to the year ending September 2002⁷. The reliability data can be affected by good and bad weather conditions, although interruptions within a distributor's network which affect at least five per cent of customers and are due to widespread storms and flooding or other natural disaster are excluded from the data. Energex has argued that the deterioration in reliability in 2002-03 was due partly to severe storms experienced in its network area during December 2002. This is accounted for by the exclusion event that Energex reported during 2002-03, the effect of which is shown in Figure 3. However, reliability performance deteriorated despite this event as shown in Table 10 which omits excluded events.

Table 9: Energex – average number and duration of total interruptions per customer

	September 2002	December 2002	March 2003	June 2003
Average number of interruptions per customer (SAIFI)	2.05	2.30	2.40	2.38
Average duration of each interruption (CAIDI) – minutes	92.0	96.8	95.1	95.5
Duration of all interruptions per customer (SAIDI) – minutes	188.3	222.6	228.7	227.8

Table 10 shows that the majority of interruptions on Energex's network were distribution-related. Specifically, the average number and duration of distribution-related interruptions increased from 1.92 and 169.9 minutes respectively for the year ending September 2002 to 2.09 and 188.3 minutes respectively for 2002-03.

Table 10: Energex – average number and duration of distribution-related interruptions per customer

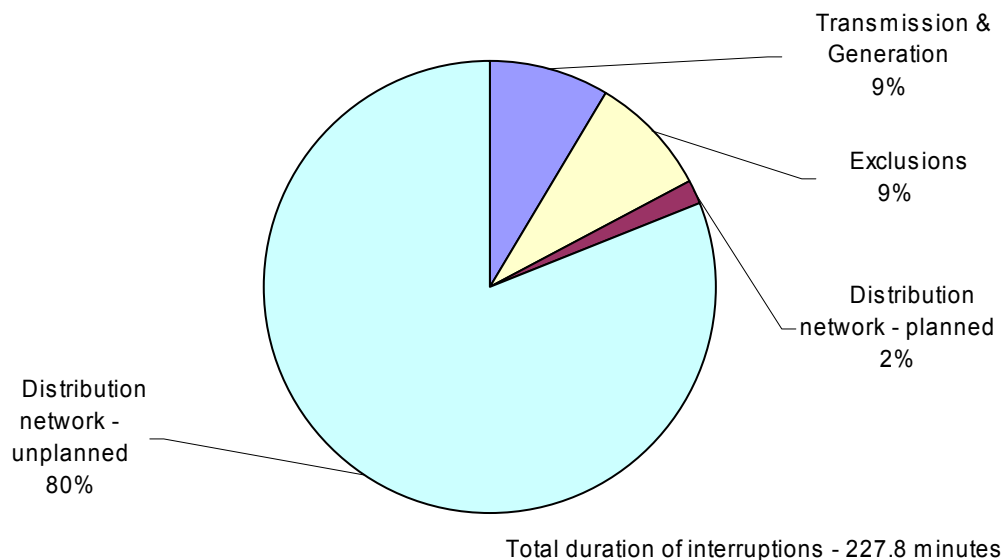
	September 2002	December 2002	March 2003	June 2003
Average number of interruptions per customer (SAIFI)	1.92	2.01	2.07	2.09
Average duration of each interruption (CAIDI) - minutes	88.5	93.3	91.0	90.0
Duration of all interruptions per customer (SAIDI) – minutes	169.9	187.1	188.4	188.3

Unplanned interruptions arising in the distribution network accounted for the majority (80 per cent) of the total 227.8 minutes that Energex customers were without electricity supply during

⁷ The quarterly reliability measures are based on 12 month rolling averages. As a result, reliability data for the June quarter in 2003 reflects reliability performance during 2002-03. Similarly, reliability data for the September quarter in 2002 reflects reliability performance during the previous 12 months.

2002-03, as shown in Figure 3. Transmission and generation interruptions together accounted for 9 per cent of outages, as did exclusions. Planned interruptions on the distribution network made up the 2 per cent balance.

Figure 3: Energex – duration of interruptions by source



Interruptions arising in the distribution network can be disaggregated according to geographic categories – that is, Central Business District (CBD), Urban and Short Rural.⁸ As shown in Table 11, there were significant differences in the level of, and changes in, reliability across Energex’s network during 2002-03. For example, while the period of time that customers in the CBD were without supply decreased by 4.6 minutes from an already low level, customers in urban and short rural areas experienced increases in the duration of interruptions of 15 minutes and 25 minutes respectively.

Table 11: Energex – duration of distribution-related interruptions by network type (minutes)

	September 2002	December 2002	March 2003	June 2003
Total distribution system	169.9	187.1	188.4	188.3
CBD	5.8	2.4	2.4	1.2
Urban	145.5	164.7	160.4	160.6
Short Rural	218.0	231.5	243.4	242.8

Reliability of worst performing feeders

During 2002-03, Energex’s 10 worst performing urban feeders supplied electricity to 8,518 customers (equivalent to 0.74 per cent of Energex’s total customer base). On average, these customers experienced between 3 and 9.8 distribution-related interruptions, leaving them without power for between 12.6 hours and 23.5 hours.

Over the same period, Energex’s 10 worst performing short rural feeders supplied electricity to 6,641 customers (equivalent to 0.57 per cent of Energex’s total customer base). On average,

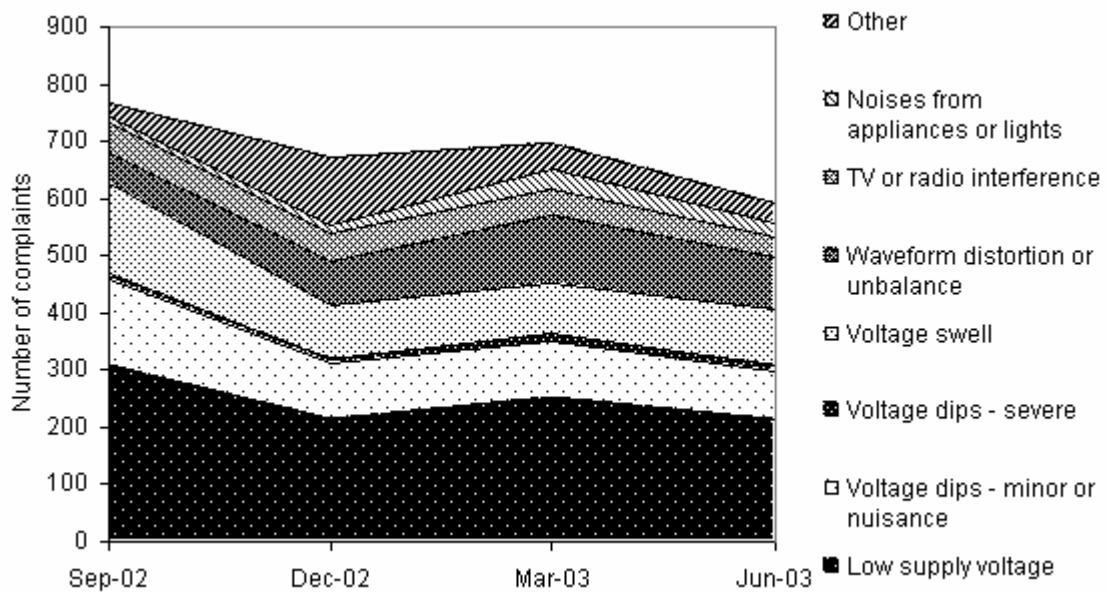
⁸ Energex does not have any feeders that meet the definition of Long Rural.

these customers experienced between 3.2 and 11.9 distribution-related interruptions, leaving them without power for between 15 hours and 32 hours.

Quality of supply measures

The total number of quality of supply complaints received by Energex decreased over 2002-03, from 768 during the September quarter of 2002 to 596 in the June quarter of 2003. As shown in Figure 4, problems associated with low supply voltage, such as light dimming and motor starting problems, accounted for the largest share of complaints and the largest reduction in complaints over 2002-03.

Figure 4: Energex – quality of supply complaints – categorised according to symptoms



Note – voltage spikes are excluded as Energex only started reporting these from the June quarter 2003, during which period there were 4 complaints.

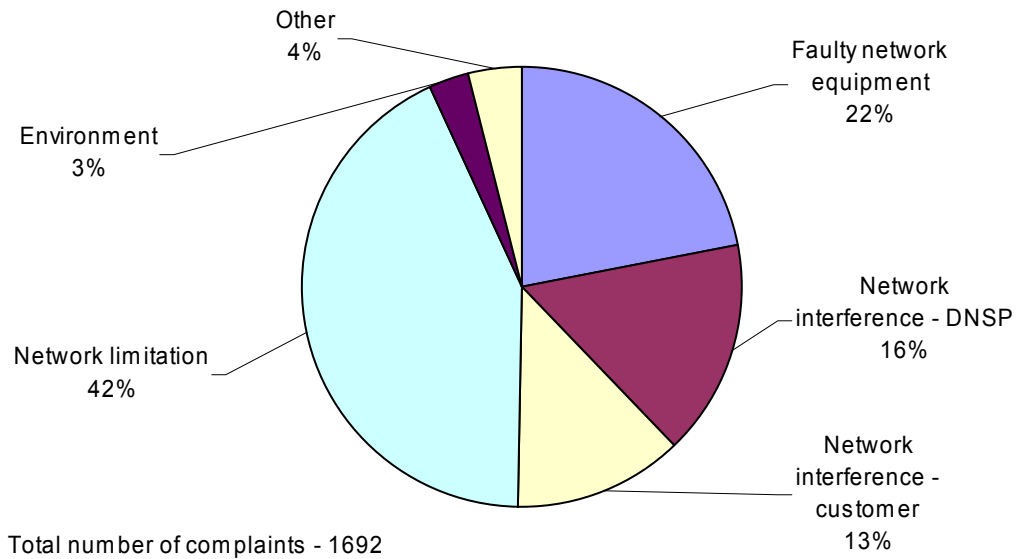
While the total number of quality of supply complaints decreased over 2002-03, the average time taken to investigate and resolve a quality of supply complaint increased significantly, from 7.9 days in the September quarter 2002 to 14.6 days in the June quarter 2003 (Table 12).

Table 12: Energex – average time taken to fix a technical supply fault

	September 2002	December 2002	March 2003	June 2003
Average time taken to fix a technical supply fault (days)	7.9	10.6	10.6	14.6

As shown in Figure 5, limitations in the distribution network were the underlying cause of most customer complaints during 2002-03. These are defined as problems which required Energex to invest in their network to resolve, for example, by increasing network capacity, upgrading plant or altering control settings. Faulty network equipment and interference to the network arising from the operation of equipment, by both customers and Energex, explained most of the remaining quality of supply complaints.

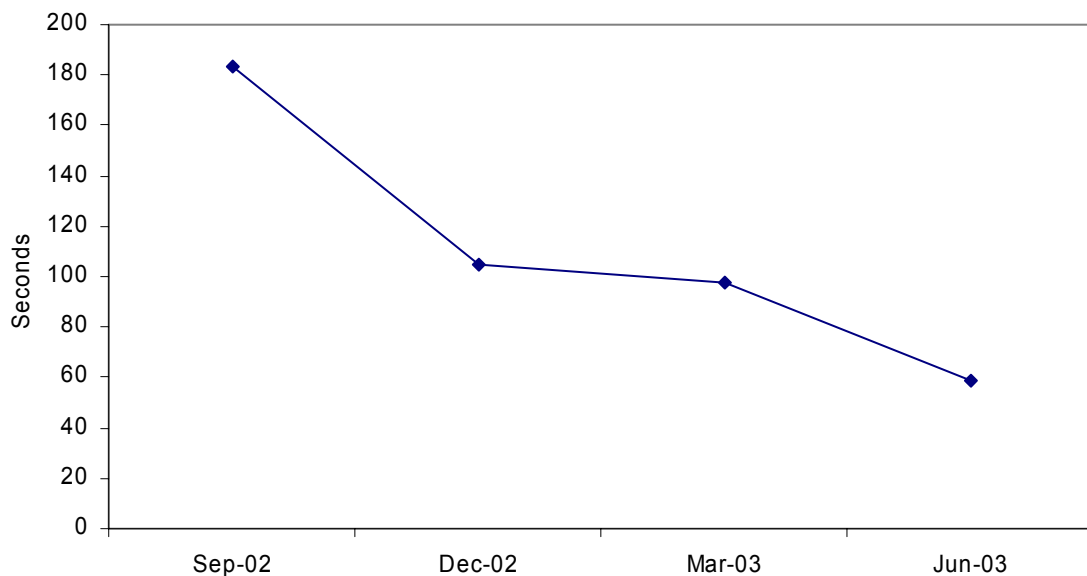
Figure 5: Energex – quality of supply complaints – possible causes



Customer service measures

Energex’s performance against a range of customer service measures was mixed over the course of 2002-03. Energex’s call centre performance improved over 2002-03. As shown in Figure 6, the length of time that customers had to wait to speak to an operator when calling the call centre fell significantly, from 3 minutes and 3 seconds during the September quarter 2002 to 59 seconds in the June quarter 2003. This meant that 65.5 per cent of calls were answered within 30 seconds at the end of 2002-03.⁹

Figure 6: Energex – average time waiting to speak to an operator



Reflecting the improved performance of the call centre, the percentage of calls that were abandoned by callers declined steadily from 17.0 per cent in the September quarter 2002 to 7.3 per cent in the June quarter 2003 (Table 13).

⁹ Energex only commenced reporting on this basis from the March quarter 2003.

Table 13: Energex – percentage of calls to the call centre that were abandoned by customers

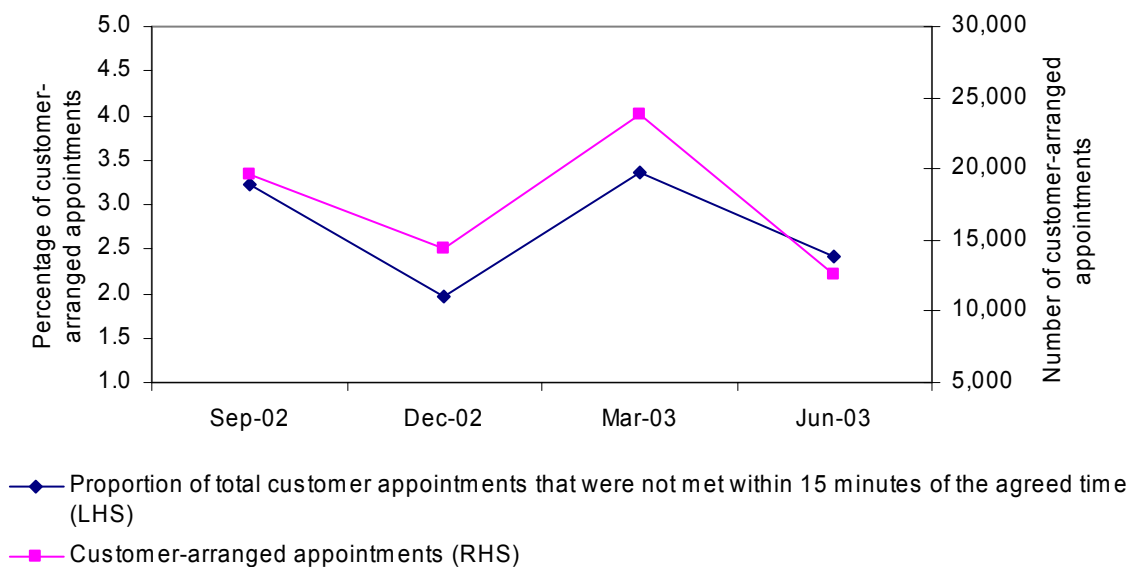
	September 2002	December 2002	March 2003	June 2003
Percentage of calls abandoned	17.0	14.3	11.0	7.3

The number of complaints that Energex received regarding the reliability of supply increased steadily over the first three quarters of 2002-03, from 200 in the September quarter 2002 to 296 in the March quarter 2003, before falling significantly to 122 in the June quarter 2003, even though reliability performance was relatively static (Table 14).

Table 14: Energex – number of reliability complaints

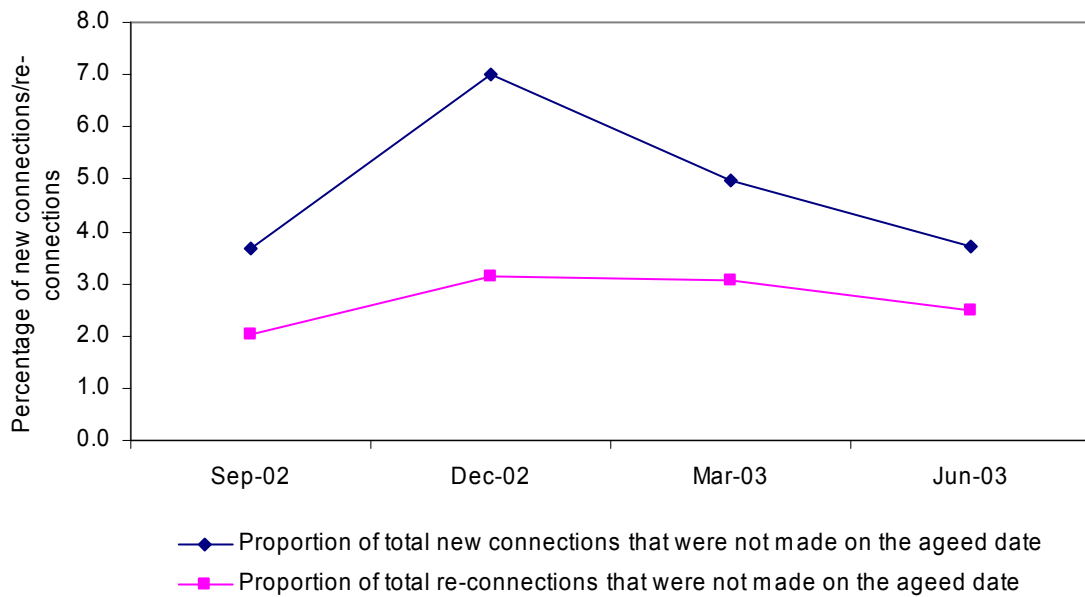
	September 2002	December 2002	March 2003	June 2003
Number of reliability complaints	200	248	296	122

The total number of appointments made and the proportion not met by Energex within 15 minutes of the agreed time varied significantly quarter-to-quarter during 2002-03, but fell overall (Figure 7). Missed appointments varied in line with the total number of appointments made. As a result, the proportion of total appointments that were not met within 15 minutes of the agreed time fell from 3.2 per cent to 2.4 per cent over the year.

Figure 7: Energex – appointment punctuality

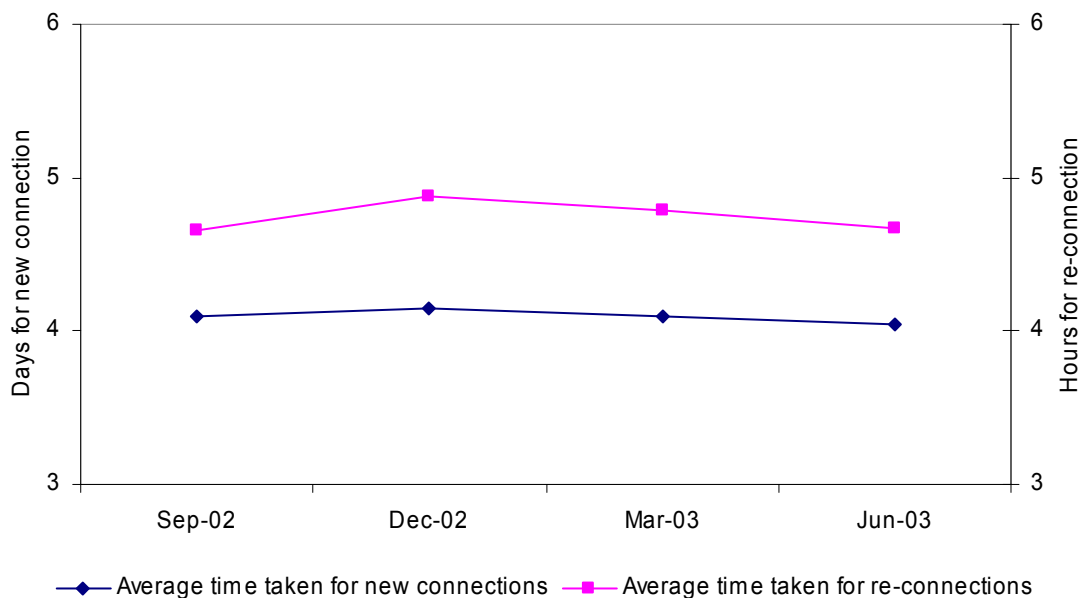
The proportion of total new supply connections that Energex failed to make by the agreed date was 3.7 per cent during the first and last quarters of 2002-03, but peaked at 7 per cent during the December quarter 2002 (Figure 8). The proportion of total re-connections of supply that were not made on the agreed date varied from 2.0 per cent in the September quarter 2002 to 2.5 per cent in the June quarter 2003, after rising to 3.1 per cent in the March quarter of 2003.

Figure 8: Energex – proportion of new connections and re-connections not made on the agreed date



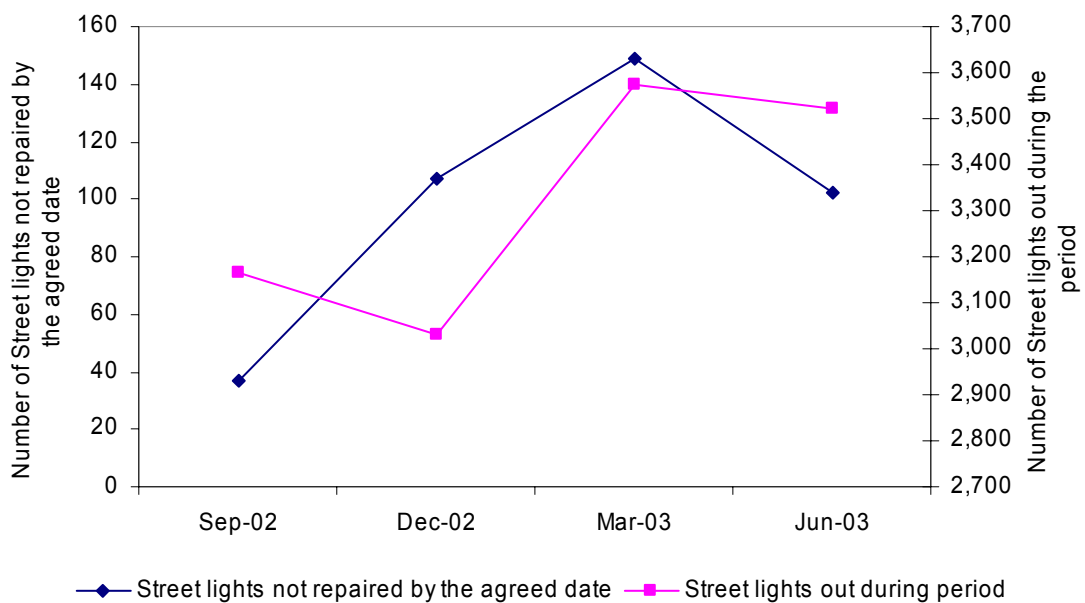
As indicated in Figure 9, the length of time that customers had to wait for a new connection to the network varied little over 2002-03, at just over 4 days. Similarly, the time that customers had to wait to be re-connected varied little over the year, between 4.5 and 5 hours.

Figure 9: Energex – average time taken for new connections and re-connections



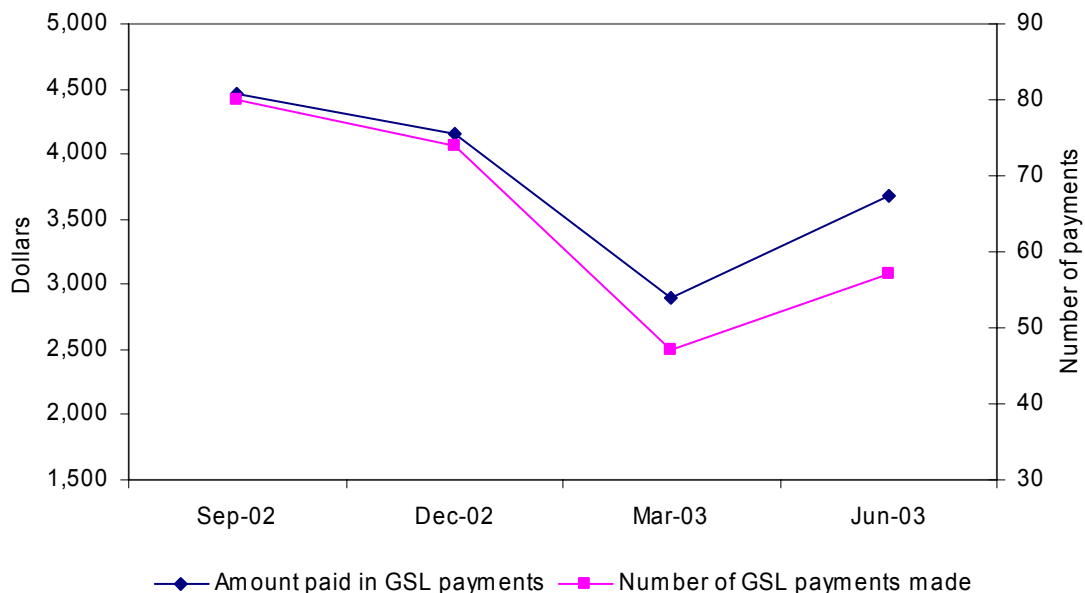
The number of street lights reported as being out increased from 3,166 in the September quarter 2002 to 3,521 in the June quarter 2003 (Figure 10). While the average time taken to repair faulty street lights fell from 4.3 days in the September quarter 2002 to 3.5 days in the June quarter 2003, the timeliness of Energex’s street light maintenance deteriorated, with the number of street lights not repaired by the agreed date increasing from 37 in the September quarter 2002 to 102 in the June quarter 2003.

Figure 10: Energex – street light maintenance



The number of Guaranteed Service Level (GSL) payments decreased from 80 payments in the September quarter 2002 to 57 payments in the June quarter 2003 and the amount paid in GSL payments also decreased from \$4462 to \$3685 over the same period (Figure 11).¹⁰ The very low number of GSL payments and amount paid could suggest that Energex’s customers are generally unaware of the GSL scheme.

Figure 11: Energex – guaranteed service level payments



Energex’s performance in relation to notification of planned interruptions was mixed (Table 15). For example, the proportion of occasions on which the required notice of a planned interruption to supply was not given increased from 7.0 per cent in the March quarter 2003 to

¹⁰ GSLs are voluntary payments made by the distributors to customers that report instances where the distributors have not met self-imposed service quality standards.

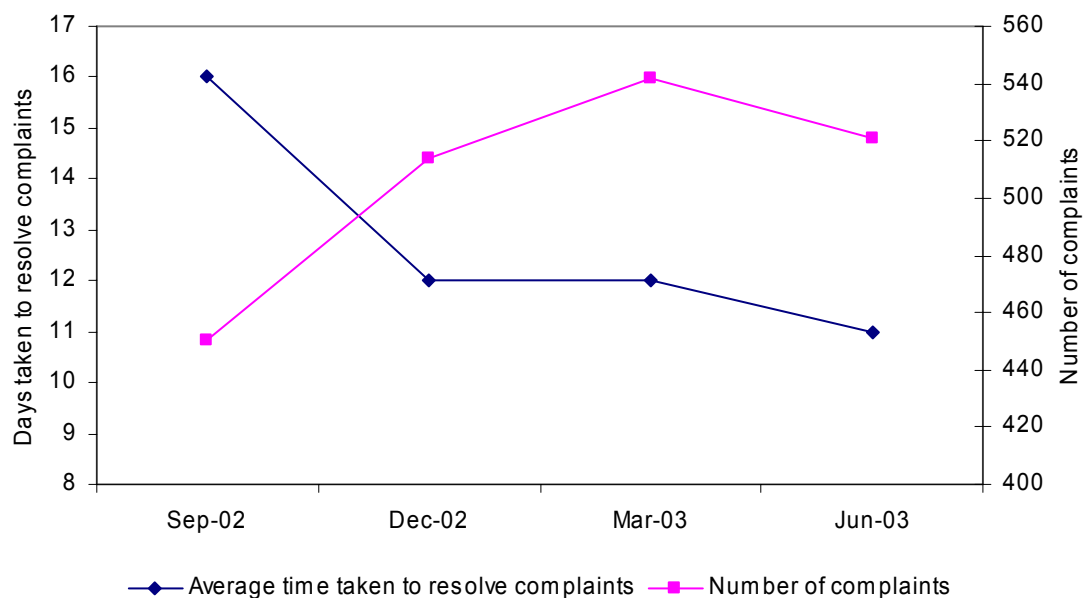
25.0 per cent in the June quarter 2003.¹¹ In contrast, the proportion of occasions on which the duration of a planned interruption exceeded the time specified in the notification decreased from 50 per cent in the September quarter 2002 to 35 per cent in the June quarter 2003.

Table 15: Energex – notification of commencement and duration of planned interruptions

	September 2002	December 2002	March 2003	June 2003
Percentage of planned interruptions for which required notice was not given	Not provided	Not provided	7.0	25.0
Percentage of planned interruptions that exceeded the time specified	50.0	46.0	39.0	35.0

While the total number of complaints received by Energex increased from 450 in the September quarter 2002 to 521 in the June quarter 2003, the average time taken to resolve complaints decreased from 16 days to 11 days over the same period (Figure 12).

Figure 12: Energex – complaint resolution

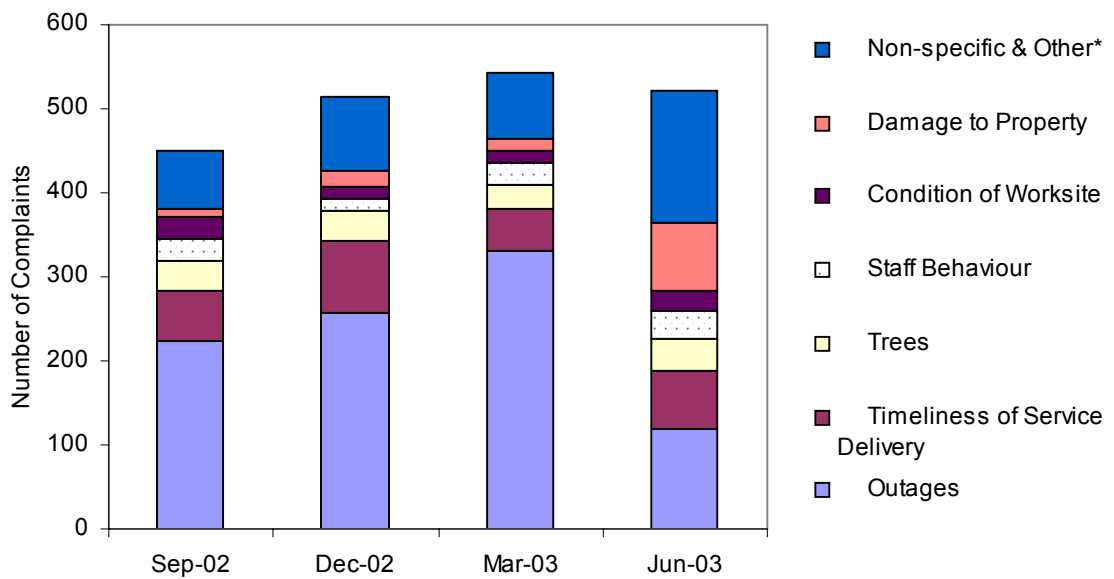


As shown in Figure 13, outages were the single most important cause of complaints during 2002-03. A significant decrease in the number of complaints about outages in the June quarter 2003 was offset by an increase in complaints about damage to property and other non-specific complaints. The high number of non-specific complaints indicates that greater disaggregation of this complaint category may be warranted.

Energex resolved 82 per cent of total complaints within 20 minutes during the June quarter 2003, compared to 89 per cent in the September quarter 2002. The average time taken to resolve repeat complaints increased from 10 days in the September quarter 2002 to 17 days in the June quarter 2003, while the number of repeat complaints in those quarters increased from 5 to 6 respectively (Figure 14). Both measures dipped significantly during the middle of 2002-03.

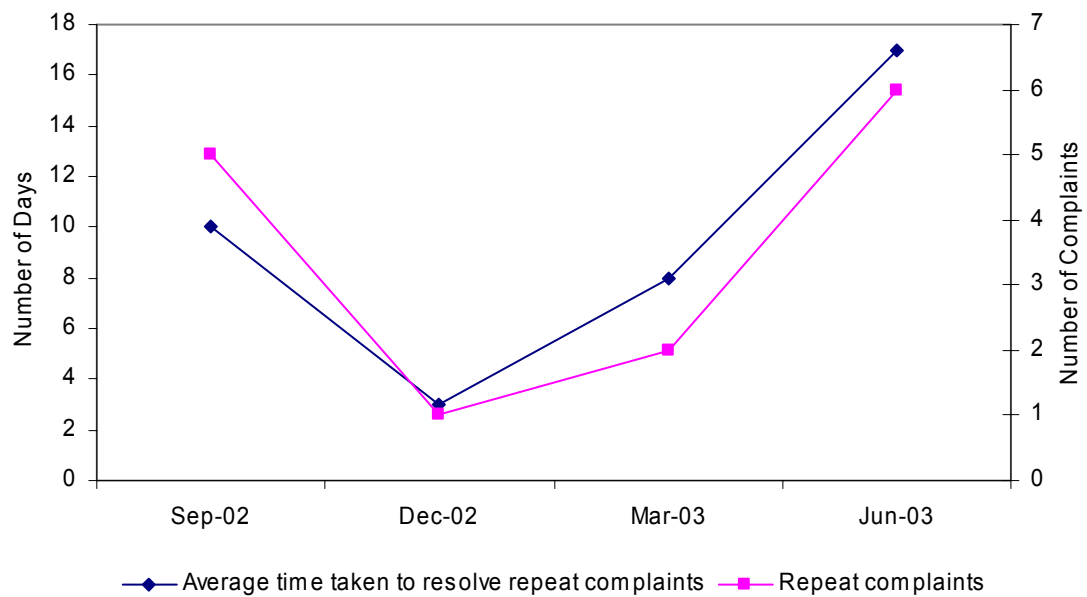
¹¹ Care should be taken in interpreting this increase because this is only the second quarter the measure has been reported by Energex. A clearer picture of performance will emerge as more data is reported.

Figure 13: Energex – reasons for complaints



* Non-specific & Other category includes complaints for general, vehicles, driving, street lights, poles and transformer complaint categories.

Figure 14: Energex – repeat complaint resolution



3. ERGON ENERGY

3.1 Customer Profile

In 2002-03, all customers with an average consumption of more than 200MWh a year, approximately 5,000 customers, were eligible to become contestable. The contestable customer groups of Ergon Energy consist of: individually calculated customers (those customers whose electricity consumption is sufficiently large to warrant individually calculated prices); connection asset customers (those customers whose electricity consumption is sufficient to warrant individually calculated connection charges but their remaining charges are averaged); and standard asset customers (customers who pay averaged charges). The non-contestable customer group incorporates all franchise customers (customers who access a franchise price). The number of customers in each category and the corresponding units of electricity sold to each is presented below for Ergon Energy.

Table 16: Customer numbers and units sold – Ergon Energy 2002-03

Customer type	Customers		Units sold		Units sold per customer	
	Number	Percentage change from previous year	MWh	Percentage change from previous year	MWh/customer	Percentage change from previous year
Contestable customers						
Individually calculated customers	57	5.6	3,814,618	5.4	66,923.1	(1.3)
Connection asset customers	45	9.8	488,005	(8.5)	10,844.6	(16.6)
Standard asset customers	311	13.1	258,621	7.8	831.6	(4.7)
Non-contestable customers						
Franchise customers ¹	584,463	1.8	7,899,326	(0.5)	13.5	(2.2)
Embedded generators	2	0	-	-	-	
Total	584,878	1.8	12,460,570	1.0	21.3	(0.9)

¹ This category includes some potentially contestable customers which have not elected to enter the market.

The number of Ergon Energy customers increased 1.8 per cent during 2002-03. The greatest increases were in the Standard Asset (13.1 per cent) and Connection Asset (9.8 per cent) customer groups. Energy sales increased a modest 1.0 per cent during the year following a 5.3 per cent increase in 2001-02. This compares with forecast average growth of 3 per cent per annum over the regulatory period. Ergon Energy indicated that the lower-than-forecast growth in energy sales in 2002-03 reflects a return to more normal operating conditions following the high growth experienced in 2001-02 (5.3 per cent).

3.2 Revenue and Expenditure

This chapter summarises the financial performance of the revenue cap regulated business segment of Ergon Energy.¹² The information is for the year ended 30 June 2003. The data used in the analysis has been drawn mainly from Ergon Energy's audited Regulatory Accounting Statements. These accounts were submitted in accordance with the Authority's *Electricity Distribution: Regulatory Accounting and Information Guidelines*.

¹² In addition to the revenue cap regulated activities, there were also a small number of distribution services regulated by the Authority in 2002-03 on a cost plus 5 per cent margin basis. Revenue from these activities amounted to around \$2.0 million (0.7 per cent of total revenue).

The overall financial performance is driven by the net effect of Ergon Energy’s results in three areas: revenue; operating and maintenance expenditure; and capital expenditure. Ergon Energy’s reported results on these components compared with the corresponding forecasts that were included in the Final Determination and the previous year’s actual data are presented below. Detailed financial data tables for Ergon Energy are provided at Appendix B.

Revenue

Under/Over Recovery of Distribution Revenue

In the Final Determination, the Authority set a maximum revenue cap for each of the four years of the initial regulatory period for Ergon Energy. The maximum revenue cap allows Ergon Energy to earn a return on assets, plus an allowance for depreciation and operating expenditure incurred in the delivery of prescribed distribution services. The Final Determination also acknowledged the possibility of within-period adjustment to revenue caps to allow for agreed cost pass-throughs or corrections to the underlying revenue cap calculations. A cost pass-through allows Ergon Energy to increase (decrease) its revenue cap in response to an increase (decrease) in a cost that was unforeseen at the time of the Final Determination, is typically beyond its control and is readily observable.

During 2002-03 cost pass-through was permitted for costs associated with the introduction of the Electrical Safety Office. Under legislation introduced by the Queensland Government, a number of functions previously undertaken by Ergon Energy were transferred to the Electrical Safety Office within the Department of Industrial Relations. The Electrical Safety Office is funded via a levy on both distributors.

The Authority reviewed Ergon Energy’s application for pass-through of costs associated with the Electrical Safety Office and approved an additional \$1.65 million of revenue to be raised in 2002-03 by Ergon Energy.

As part of the Final Determination, the Authority stated its intention to use an “unders and overs” account applying to each DNSP to ensure compliance with the annual revenue caps set in the Determination. The unders and overs process compares actual revenue earned in the year against the annual revenue cap for that year as determined by the Authority.

Table 17: Ergon Energy DUOS revenue – 2002-03

	\$ million (nominal)
Actual Revenue earned during 2002-03 ¹	
Revenue from distribution tariffs	475.5
Revenue from capital contributions	19.9
less Allowable annual revenue (updated where necessary) ²	493.2
equals Over/(under) recovery for 2002-03	2.3

¹ Does not include revenue earned from the use of regulated assets by non-regulated business segments.

² Includes distribution tariff revenue, revenue from capital contributions, and the revenue impact of an adjustment to correct for errors in the asset base.

Table 17 indicates that Ergon Energy over-recovered their allowed revenue by \$2.3 million (0.5 per cent). As per the Authority’s Final Determination, an over-recovery balance of less than 2 per cent requires each of the distributors to clear the balance of their unders and overs account

during the subsequent (2004-05) pricing period.¹³ Accordingly, the revenue over-recovery by Ergon Energy during 2002-03 will be rolled-forward and reflected in their respective allowable revenue for 2004-05 to be returned to all customer classes through 2004-05 distribution prices.

Under/Over Recovery of Transmission Use of System (TUOS) Charges

TUOS charges are calculated by DNSPs each year to pass-through to distribution customers the cost levied by Powerlink for the use of the transmission system.¹⁴ Electricity transmission charges are regulated by the Australian Competition and Consumer Commission (ACCC) and paid to Powerlink by DNSPs on behalf of end-customers. The Authority approves TUOS charges to be levied by the distributors that are intended to allow them to recover the TUOS charges they have paid to Powerlink. In approving the (DNSP's) TUOS charges, the Authority's main aim is to ensure that these charges should reflect, as closely as possible, the structure of Powerlink's charges. Any difference between TUOS revenue recovered by DNSPs from customers and the charges they paid to Powerlink is recouped from/returned to customers through future (DNSP) TUOS charges.

Table 18: Ergon Energy TUOS unders and overs account – 2002-03¹

	\$ million (nominal)
TUOS charged by Powerlink	153.0
<i>less</i> actual TUOS revenue earned during 2002-03	154.4
<i>equals</i> Over/(under) recovery for 2002-03	1.4

¹ Numbers are rounded.

Table 18 indicates that Ergon Energy's customers were charged \$1.4 million more than cost during 2002-03 for transmission services. Accordingly, Ergon Energy will be required to return their over-recovery of TUOS charges to customers as part of their 2004-05 TUOS charges.

Operating and Maintenance Expenditure

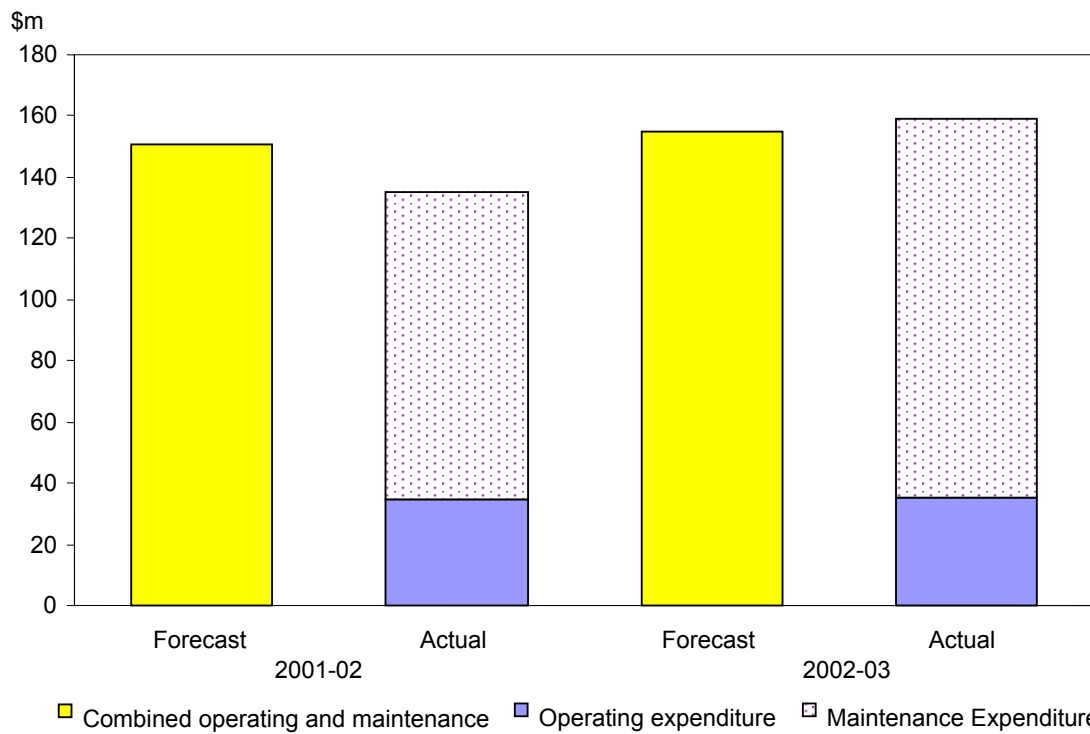
The regulatory framework is designed to give the distribution businesses an incentive to increase their forecast return by improving their efficiency and hence reducing costs. To this end, the distributors retain the benefit of any efficiency gain for the remainder of the regulatory period (or longer if provision were made for carry-over between regulatory periods).

Figure 15 shows network operating and maintenance expenditure reported by Ergon Energy for 2001-02 and 2002-03, compared with the forecast operating and maintenance expenditure in the Final Determination.

¹³ Distribution prices for 2003-04 were required to be set in May 2003, before the receipt of the distributor's 2002-03 Regulatory Accounting Statements. This timing will always be the case meaning there will always be a 2 year lag between establishing an under/over recovery has occurred and its recoupment/return.

¹⁴ TUOS charges are separately identified from DUOS charges under the Queensland electricity distribution pricing regime.

Figure 15: Ergon Energy operating and maintenance expenditure – 2001-02 and 2002-03¹

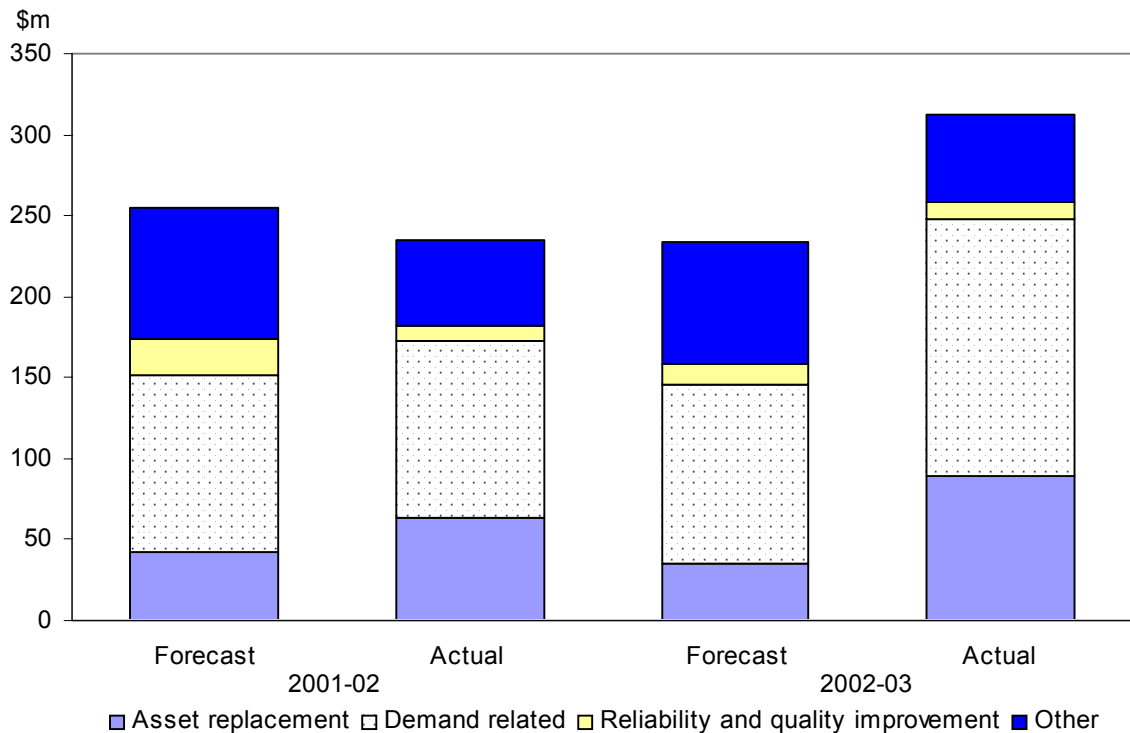


¹ The Final Determination contains forecasts of combined operating and maintenance expenditure rather than separate forecasts for operating expenditure and maintenance expenditure

Following lower-than-forecast operating and maintenance expenditure in 2001-02 of \$15.9 million, Ergon Energy recorded an over-spend of \$4.4 million (2.8 per cent) in 2002-03. After allowing for the pass-through of net costs associated with the establishment of the Electrical Safety Office, the over-spend is reduced to \$2.75 million (1.8 per cent). Last year, Ergon Energy indicated that it expected the shortfall in expenditure in 2001-02, due primarily to the introduction of its Asset Inspection and Defect Management (AIDM) program, to be caught-up over the remainder of the regulatory period.

Capital Expenditure

Figure 16 shows network capital expenditure (in aggregate and by purpose) reported by Ergon Energy for 2001-02 and 2002-03, compared with the forecast capital expenditure.

Figure 16: Ergon Energy capital expenditure – 2001-02 and 2002-03

Capital expenditure of \$312.8 million was \$78.8 million (33.7 per cent) higher than forecast during the year. However, Ergon Energy recorded lower-than-forecast capital expenditure in 2001-02 (\$20.0 million lower) which offsets the 2002-03 over-spend to some extent.

Expenditure in 2002-03 was over 150 per cent higher-than-forecast (and higher than the previous year) on asset replacement expenditure. Ergon Energy attributed the increased expenditure to the continued impact of the AIDM program introduced in 2001-02. The AIDM program (particularly in its first inspection phase of the network) identified asset replacement requirements additional to Ergon Energy's existing asset replacement program. Ergon Energy anticipates that, once the initial inspections have been completed for all relevant assets, the impact of the AIDM program on capital expenditure will decline. Nevertheless, the AIDM program is expected to contribute to higher-than-forecast asset replacement expenditure in 2003-04 and 2004-05

Ergon Energy also recorded a significant over-spend on demand related expenditure (\$48.5 million or 43.7 per cent). Ergon Energy attributed this to difficulties associated with forecasting augmentation work and customer requested works at the start of the regulatory period. In particular, Ergon Energy indicated that there was additional expenditure related to three large mining related projects that were not anticipated at the time of the Final Determination. These projects relate (generally) to mineral resources known at the time, but the timing of their development was difficult to anticipate. Maximum network demand increased by 8.5 per cent during 2002-03.

'Other' capital expenditure was \$20.6 million or 27.5 per cent lower than expected. Given the sharp increase in asset replacement expenditure, Ergon Energy decided to defer some non-system expenditure. In particular, planned expenditure on the Enterprise Resource Planning system of \$21 million was not undertaken during the year. The expenditure for this system is now expected to be staged over several years from 2003-04 onward rather than a single implementation during 2002-03.

3.3 Service Quality

This section summarises the service quality performance of the revenue cap regulated business segment of Ergon Energy. The information is for the year ended 30 June 2003 and, unless otherwise indicated, has been drawn from Ergon Energy's quarterly and annual service quality reports for 2002-03. These reports were submitted in accordance with the Authority's *Electricity Distribution: Service Quality Reporting Guidelines*. The Authority commenced posting the quarterly reports provided by the DNSPs on its website with the September quarter 2002 reports (released February 2003).

As data accumulates over time, the service quality performance of Ergon Energy will be able to be better assessed. As this is the first annual report to be released, the data should be treated with caution.

The service quality measures collected by the Authority are not intended to allow comparison of the two DNSPs with each other. This is because Energex and Ergon Energy operate in very different environments, as discussed in Chapter 1. As a result, it is to be expected that the distributors' performance will vary significantly on a number of service quality measures.

The service quality measures that the DNSPs are required to report against fall into three broad groups – reliability measures, quality of supply measures and customer service measures.

Reliability measures provide information about interruptions to electricity supply. Interruptions can occur because of problems with generation, transmission or distribution. Distribution interruptions may be planned or unplanned, and unplanned interruptions will at times be due to events that are beyond the control of the DNSPs, such as severe storms. A DNSP's performance is best indicated by the duration and frequency of planned and unplanned interruptions that are due to distribution network problems within the distributor's control (although lengthy and frequent interruptions due to other influences may indicate a need for improved risk management measures on the part of the distributors). Reliability data for worst performing feeders highlights pockets of the network where customers experience relatively poor service quality.

Quality of supply measures are intended to indicate problems with the nature of electricity supply, such as low or high voltage levels, based on customers reporting symptoms that are typically associated with such problems. For example, low supply voltage would be evidenced by complaints relating to light dimming or motor starting problems.

Customer service measures provide information about how customers' problems, enquiries and requests for services are handled by the DNSPs.

Reliability measures

During 2002-03, Ergon Energy's customers, on average, experienced 5.18 interruptions as a result of interruptions arising from all segments of the electricity supply chain, including generation, transmission and distribution. With each interruption lasting an average of 105.1 minutes, customers, on average, were left without power for a total of 544.6 minutes over the year.

As shown in Table 19, the number and duration of interruptions have increased from 4.42 and 452.8 minutes respectively since the first quarter of 2002-03, indicating a deterioration in the

reliability of electricity supply for 2002-03 compared to the year ending September 2002¹⁵. The reliability data can be affected by good and bad weather conditions, although interruptions within a distributor's network which affect at least five per cent of total customers and are due to widespread storms and flooding or other natural disaster are excluded from the data. For Ergon Energy, with its low customer density, it requires a fairly extreme event (such as a cyclone) to affect more than 5 per cent of total customers. No events were excluded from Ergon Energy's reliability data in 2002-03.

Table 19: Ergon Energy – average number and duration of total interruptions per customer

	September 2002	December 2002	March 2003	June 2003
Average number of interruptions per customer (SAIFI)	4.42	5.29	5.00	5.18
Average duration of each interruption (CAIDI) - minutes	102.4	102.5	105.9	105.1
Duration of all interruptions per customer (SAIDI) – minutes	452.8	542.2	529.6	544.6

Table 20 shows that the majority of interruptions on Ergon Energy's network were distribution-related. Specifically, the average number and duration of distribution-related interruptions increased from 4.34 interruptions and 451.0 minutes for the year ending September 2002 to 4.50 interruptions and 494.8 minutes for 2002-03.

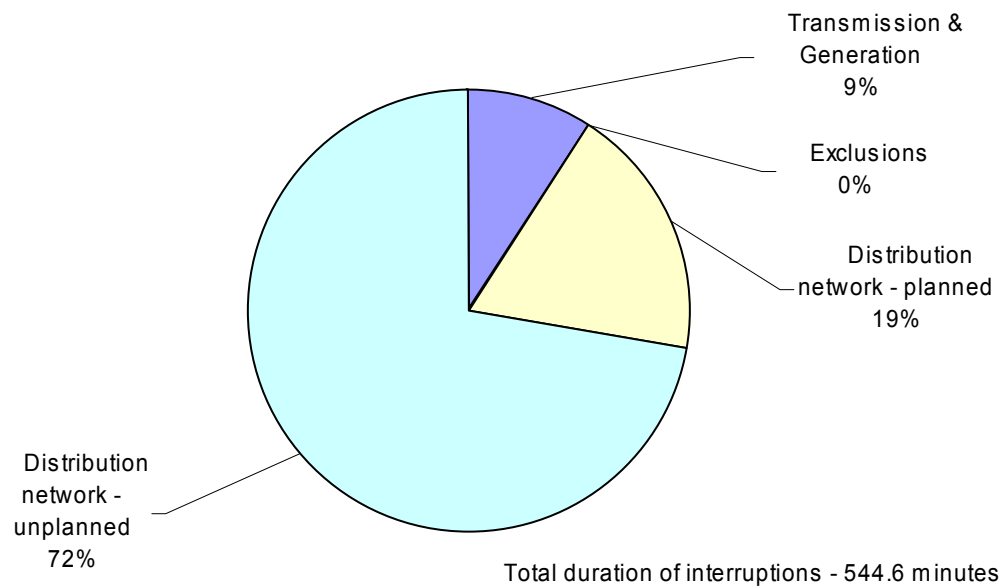
Table 20: Ergon Energy – average number and duration of distribution-related interruptions per customer

	September 2002	December 2002	March 2003	June 2003
Average number of interruptions per customer (SAIFI)	4.34	4.67	4.40	4.50
Average duration of each interruption (CAIDI) - minutes	104.0	107.0	109.0	109.8
Duration of all interruptions per customer (SAIDI) – minutes	451.0	499.9	484.0	494.8

Unplanned interruptions arising in the distribution network accounted for the majority (72 per cent) of the total 544.6 minutes that Ergon Energy customers were without electricity supply during 2002-03, as shown in Figure 17. Planned interruptions in the distribution network accounted for 19 per cent of outages. Ergon Energy has indicated that this high number is partly explained by increased asset replacement expenditure on the network due to the AIDM program. Transmission and generation interruptions together made up the 9 per cent balance. There were no exclusions during the year¹⁶.

¹⁵ The quarterly reliability measures are based on 12 month rolling averages. As a result, reliability data for the June quarter in 2003 reflects reliability performance during 2002-03. Similarly, reliability data for the September quarter in 2002 reflects reliability performance during the previous 12 months.

¹⁶ Exclusions are interruptions arising within a distributor's network which affect at least 5 per cent of customers and are due to storms, flooding or some other natural disaster.

Figure 17: Ergon Energy – duration of interruptions by source

Interruptions arising in the distribution network can be disaggregated according to geographic categories – that is, Urban, Short Rural and Long Rural.¹⁷ As shown in Table 21, there were significant differences in the level of, and changes in, reliability across Ergon Energy’s network during 2002-03. For example, the period of time that customers in long rural areas were without supply increased by 18 minutes while customers in urban and short rural areas experienced increases in the duration of interruptions of 38 minutes and 72 minutes respectively.

Table 21: Ergon Energy – duration of distribution-related interruptions by network type (minutes)

	September 2002	December 2002	March 2003	June 2003
Total distribution system	451.0	499.9	484.0	494.8
Urban	190.0	240.7	234.7	227.5
Short Rural	534.0	590.7	575.8	605.6
Long Rural	978.0	1025.8	988.2	996.0

Reliability of worst performing feeders

During 2002-03, Ergon Energy’s 10 worst performing urban feeders supplied electricity to 4,285 customers (equivalent to 0.76 per cent of Ergon Energy’s total customer base). On average, these customers experienced between 2 and 13 distribution-related interruptions, leaving them without power for between 16.3 hours and 36.1 hours.

Over the same period, Ergon Energy’s 10 worst performing short rural feeders supplied electricity to 1,905 customers (equivalent to 0.34 per cent of Ergon Energy’s total customer base). On average, these customers experienced between 11.2 and 24.7 distribution-related interruptions, leaving them without power for between 55.0 hours and 81.2 hours.

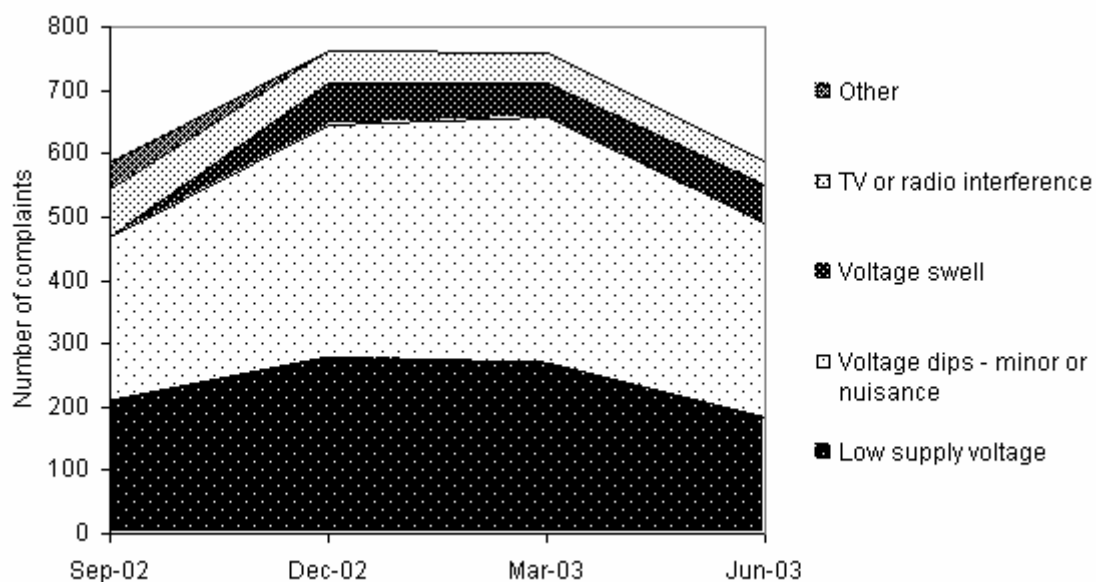
¹⁷ Ergon Energy does not have any feeders that meet the definition of CBD

The 10 worst performing of Ergon Energy's long rural feeders supplied electricity to 975 customers (equivalent to 0.17 per cent of Ergon Energy's total customer base). On average, these customers experienced between 11.8 and 37.1 distribution-related interruptions, leaving them without power for between 46.4 hours and 111.4 hours.

Quality of supply measures

The total number of quality of supply complaints received by Ergon Energy increased over the first two quarters of 2002-03, from 585 during the September quarter of 2002 to 761 in the December quarter of 2003, before falling to 589 in the June quarter 2003. As shown in Figure 18, problems associated with voltage dips – minor or nuisance (which can cause flickering light and digital clock resetting problems) and low supply voltage (which can cause light dimming and motor starting problems) accounted for the majority of quality of supply complaints.

Figure 18: Ergon Energy – quality of supply complaints – categorised according to symptoms



Note – Ergon Energy only started reporting voltage swells from the December quarter 2002.

While the total number of quality of supply complaints was similar at the beginning and end of 2002-03, the average time taken to investigate and resolve a quality of supply complaint increased significantly, from 35 days in the September quarter 2002 to 63 days in the June quarter 2003 (Table 22).

Table 22: Ergon Energy – average time taken to fix a technical supply fault

	September 2002	December 2002	March 2003	June 2003
Average time taken to fix a technical supply fault (days)	35	27	41	63

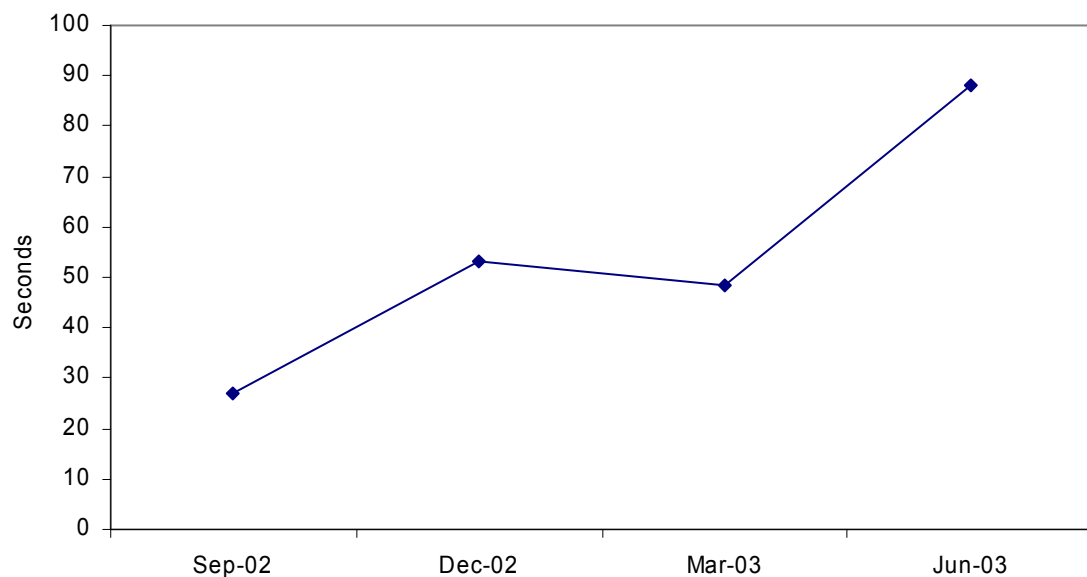
For 2002-03, there were 289 quality of supply complaints which after investigation were found to be caused by network restrictions or events on the network. The vast majority of these

complaints were not categorised. Ergon Energy intends to improve its reporting of this measure for its 2003-04 Annual Service Quality Report.

Customer service measures

Ergon Energy's performance against a range of customer service measures was mixed over the course of 2002-03. Ergon Energy's call centre performance deteriorated over 2002-03. As shown in Figure 19, the length of time that customers had to wait to speak to an operator when calling the call centre increased significantly, from 27 seconds during the September quarter 2002 to 88 seconds in the June quarter 2003. This meant that only 52.4 per cent of calls were answered within 30 seconds at the end of 2002-03.

Figure 19: Ergon Energy – average time waiting to speak to an operator



Reflecting the performance of the call centre, the percentage of calls that were abandoned by callers increased during 2002-03, up from 2.7 per cent in the September quarter 2002 to 7.1 per cent in the June quarter 2003 (Table 23).

Table 23: Ergon Energy – percentage of calls to the call centre that were abandoned by customers

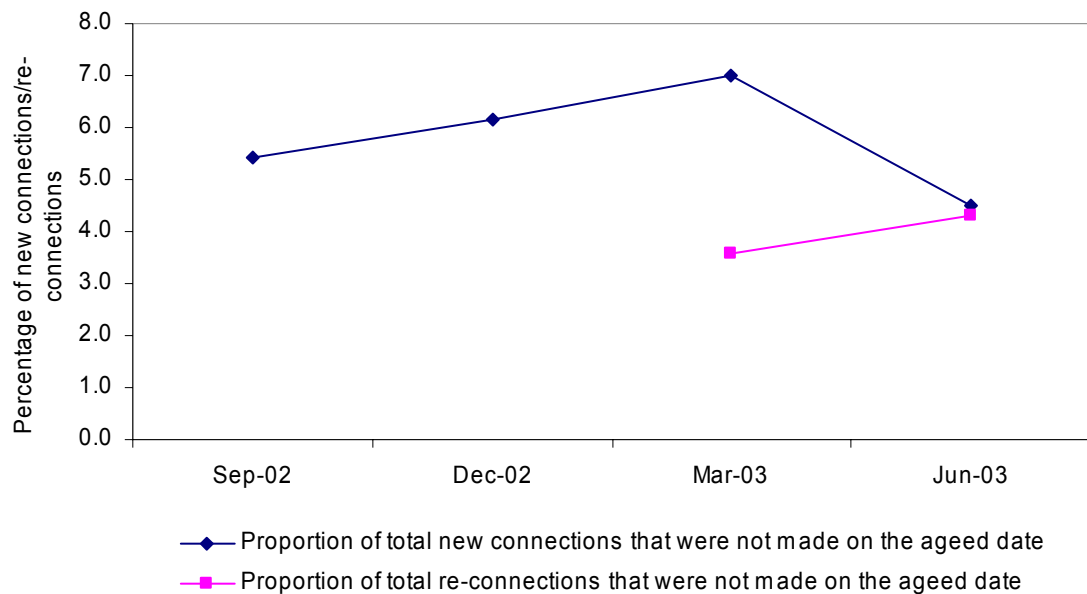
	September 2002	December 2002	March 2003	June 2003
Percentage of calls abandoned	2.7	5.7	4.8	7.1

The number of complaints that Ergon Energy received regarding the reliability of supply increased steadily over the first three quarters of 2002-03, from 168 in the September quarter 2002 to 355 in the March quarter 2003, before falling significantly to 304 in the June quarter 2003 (Table 24).

Table 24: Ergon Energy – number of reliability complaints

	September 2002	December 2002	March 2003	June 2003
Number of reliability complaints	168	249	355	304

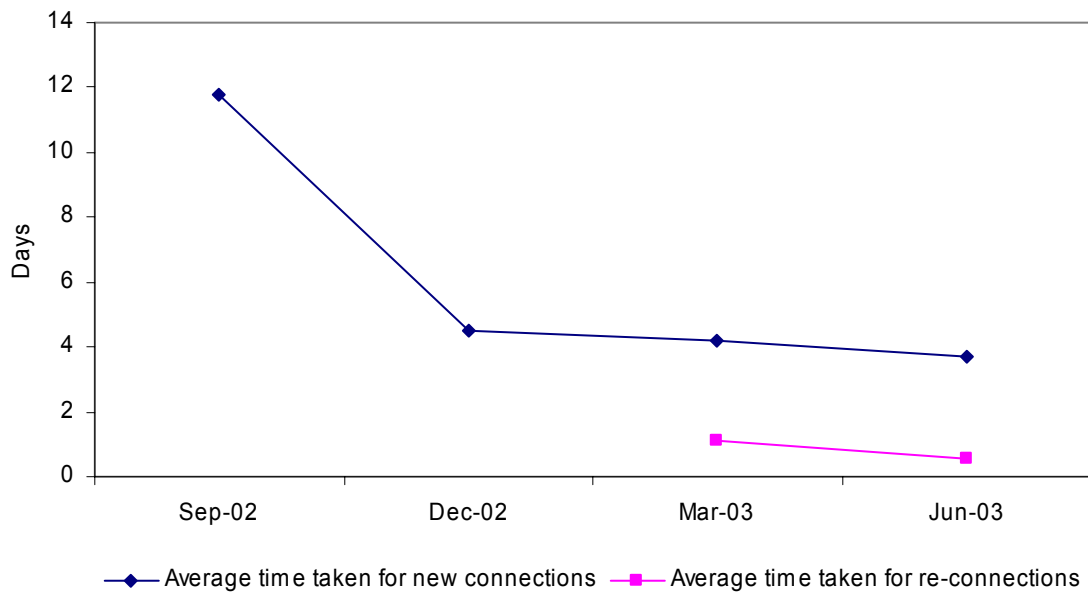
The proportion of total new supply connections that Ergon Energy failed to make by the agreed date decreased from 5.4 per cent to 4.5 per cent over the course of 2002-03 after rising to 7.0 per cent in the March quarter 2003 (Figure 20). Ergon Energy commenced reporting measures on its re-connection performance in the March quarter 2003. The proportion of total re-connections of supply that were not made on the agreed date increased from 3.6 per cent in the March quarter 2003 to 4.3 per cent in the June quarter 2003.¹⁸

Figure 20: Ergon Energy – proportion of new and re-connections not made on the agreed date

As indicated in Figure 21, the length of time that customers had to wait for a new connection to the network decreased significantly, from 11.8 days in the September quarter 2002 to 3.7 days in the June quarter 2003. Customers had to wait 26.4 hours in the March quarter 2003 to be re-connected compared to 13.4 hours in the June quarter 2003.

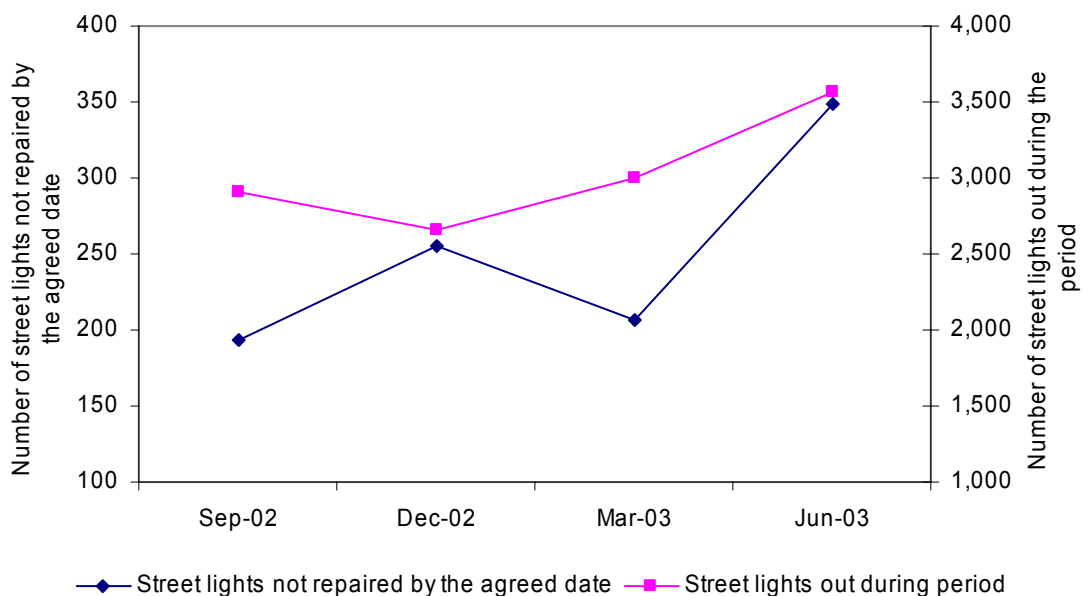
¹⁸ Care should be taken in interpreting this increase because this is only the second quarter the measure has been reported by Ergon Energy. A clearer picture of performance will emerge as more data is reported.

Figure 21: Ergon Energy – average time taken for new connections and re-connections

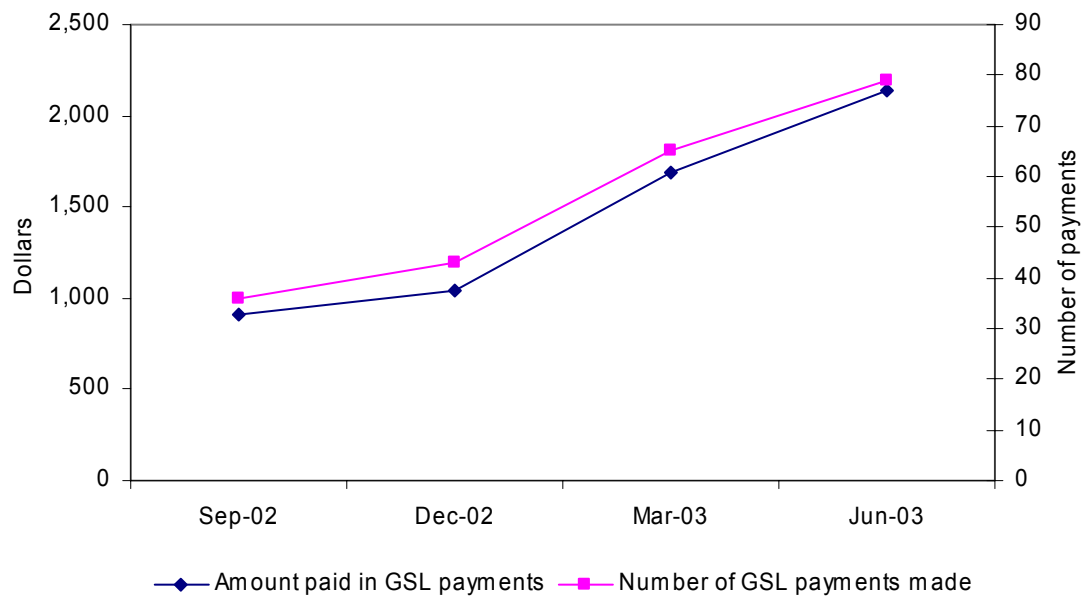


The number of street lights reported as being out increased from 2,902 in the September quarter 2002 to 3,569 in the June quarter 2003 (Figure 22). The timeliness of Ergon Energy’s street light maintenance deteriorated, with the number of street lights not repaired by the agreed date increasing from 193 in the September quarter 2002 to 349 in the June quarter 2003. The average time taken to repair faulty street lights increased from 2.3 days in the September quarter 2002 to 3.5 days in the June quarter 2003.

Figure 22: Ergon Energy – street light maintenance



The number of Guaranteed Service Level (GSL) payments increased from 36 payments in the September quarter 2002 to 79 payments in the June quarter 2003 and the amount paid in GSL payments also increased from \$905 to \$2,135 over the same period (Figure 23).

Figure 23: Ergon Energy – Guaranteed service level payments

The very low number of GSL payments and amount paid could suggest that Ergon Energy's customers are generally unaware of the GSL scheme.

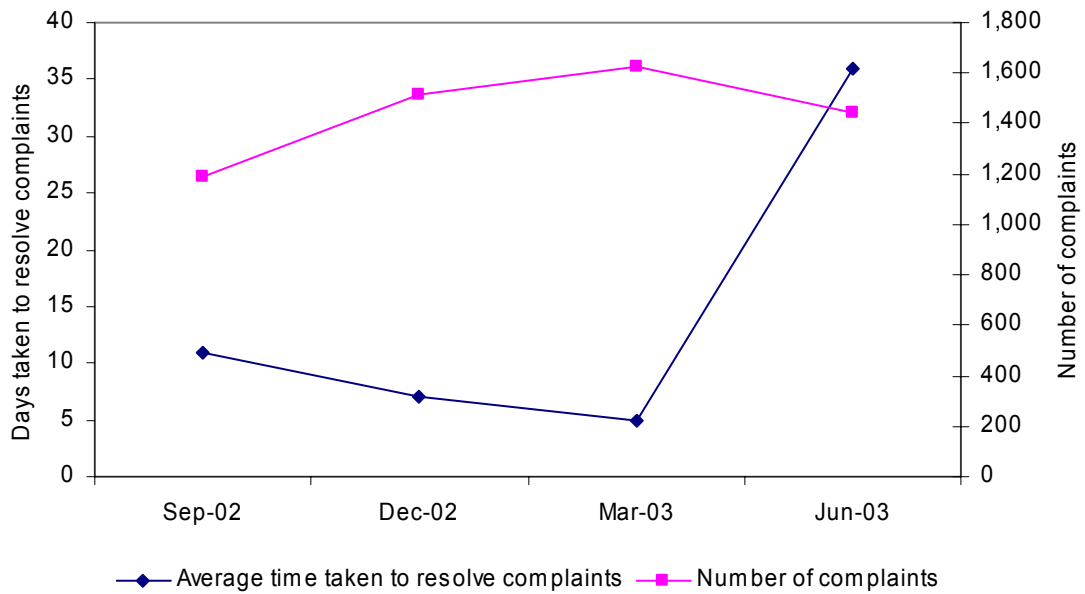
Ergon Energy's performance in relation to notification of planned interruptions was mixed. For example, the proportion of occasions on which the required notice of a planned interruption to supply was not given decreased from 4.7 per cent in the September quarter 2002 to 4.1 per cent in the June quarter 2003 (Table 25). In contrast, the proportion of occasions on which the duration of a planned interruption exceeded the time specified in the notification increased from 31.7 per cent in the September quarter 2002 to 34.6 per cent in the June quarter 2003. This is an important measure of Ergon Energy's customer service performance given the large number of planned interruptions on its network (see Figure 17).

Table 25: Ergon Energy – notification of commencement and duration of planned interruptions

	September 2002	December 2002	March 2003	June 2003
Percentage of planned interruptions for which required notice was not given	4.7	5.6	6.7	4.1
Percentage of planned interruptions that exceeded the time specified	31.7	35.4	32.8	34.6

The total number of complaints received by Ergon Energy increased from 1,187 in the September quarter 2002 to 1,441 in the June quarter 2003 and the average time taken to resolve complaints increased from 11 days to 36 days over the same period (Figure 24). However, Ergon Energy has advised of a change to the collection of data for complaint resolution to improve its accuracy, resulting in a discontinuity in the reported data and an inability to make a reliable comparison between the March and June quarters.

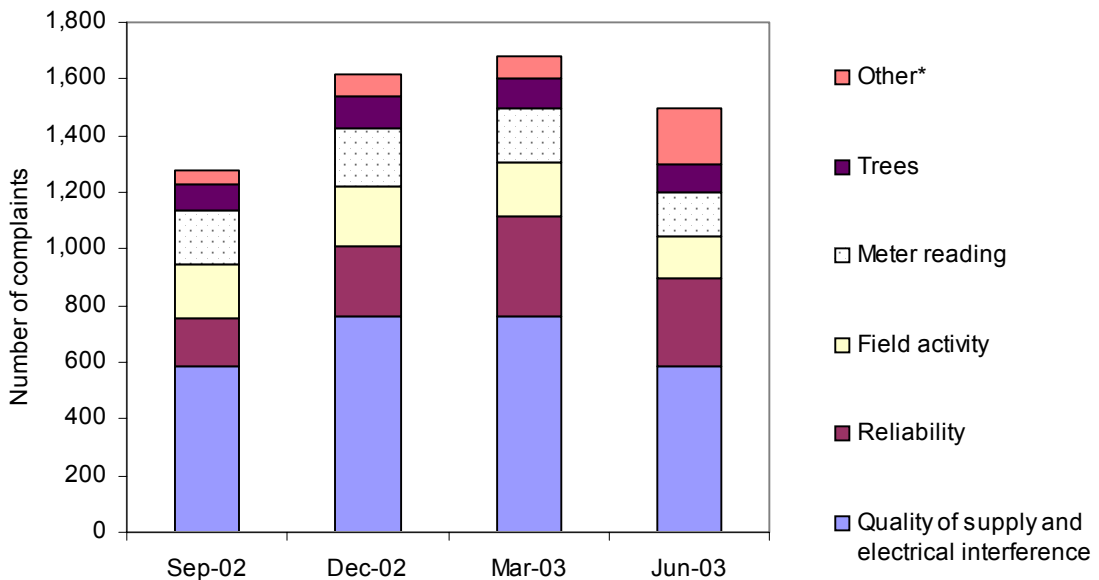
Figure 24: Ergon Energy – complaint resolution



Note – includes reliability and quality of supply complaints.

As shown in Figure 25, quality of supply and electrical interference was the most significant cause of complaints during 2002-03 with complaints relating to reliability generally increasing over the period.

Figure 25: Ergon Energy – reasons for complaints

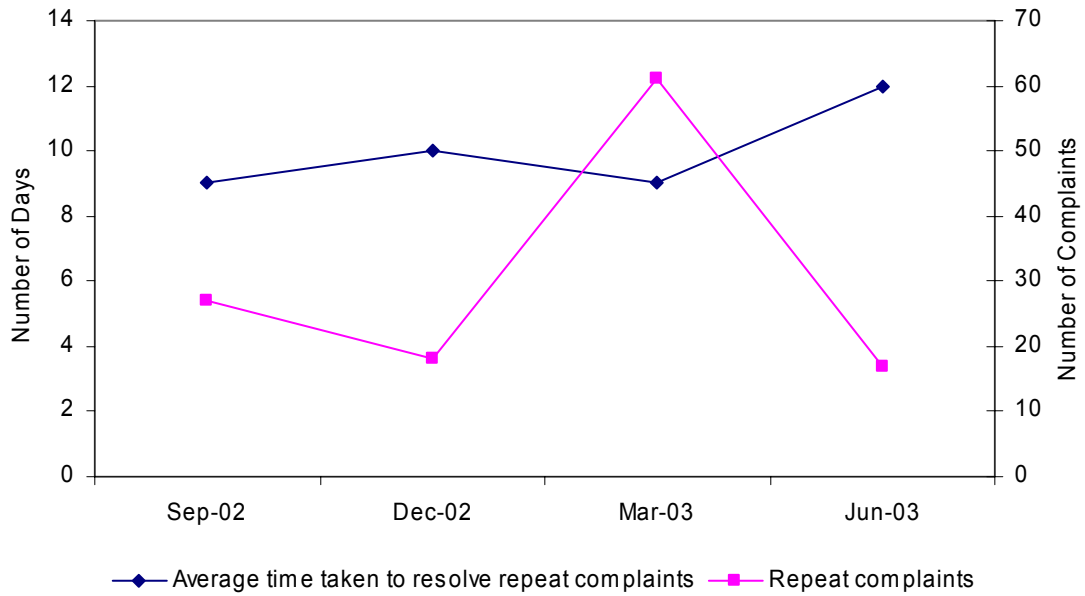


* Other category includes complaints for new extensions to supply, metering/technical, street lights, infrastructure, environmental issues, line clearances and the new categories for the June quarter 2003 of customer service and other.

Ergon Energy resolved 84.5 per cent of complaints within 20 minutes during the June quarter 2003, compared to 90.0 per cent in the September quarter 2002. However, the average time

taken to resolve repeat complaints increased from 9 days in the September quarter 2002 to 12 days in the June quarter 2003, while the number of repeat complaints in those quarters decreased from 27 to 17 respectively after peaking at 61 repeat complaints for the March quarter 2003 (Figure 26).

Figure 26: Ergon Energy – repeat complaint resolution



APPENDIX A

FINANCIAL DATA TABLES – 2001-02 and 2002-03

Table A1: Aggregate financial information – Energex (\$ million (nominal))

	2001-02	2002-03
Revenue		
Forecast income from sales	467.3	497.0
Actual income from sales	468.4	505.1
Expenditure		
Forecast operating and maintenance expenditure	161.7	168.9
Actual operating and maintenance expenditure		
Operating expenditure	49.7	15.1
Maintenance expenditure	80.5	105.9
Total	130.2	121.0
Forecast depreciation	157.0	165.3
Actual depreciation	130.6	156.7
Total expenditure (forecast)	318.7	334.2
Total expenditure (actual)	260.8	277.7
Customer contributions		
Forecast	23.3	24.0
Actual	23.9	24.8
Capital expenditure		
Forecast	254.3	257.9
Actual	270.6	281.7
Fixed assets		
Forecast	3,020.4	3,176.7
Actual	2,977.6	3,169.9
Energy Sales (million MWh)		
Actual	17.2	17.8
Number of customers		
Actual	1,105,100	1,129,940

Table A2: Revenue – Energex (\$ million (nominal))

Revenue source	Energex	
	2001-02	2002-03
Income from sales		
Network services	468.4	505.1
Public lighting	Not separately identified	
Other	126.0	160.0
Total	594.4	665.1
Capital contributions	23.9	24.8
Proceeds from sale of assets	6.3	12.9*
Other revenue	2.3	2.4
Total	626.8	705.2

* Book value of assets sold by Energex equals \$11.7 million.

APPENDIX B

FINANCIAL DATA TABLES – 2001-02 and 2002-03

Table B1: Aggregate financial information – Ergon Energy (\$ million (nominal))

	2001-02	2002-03
Revenue		
Forecast income from sales	447.5	476.05
Actual income from sales	443.9	475.5
Expenditure		
Forecast operating and maintenance expenditure	150.9	154.6
Actual operating and maintenance expenditure		
Operating expenditure	34.6	35.5
Maintenance expenditure	100.4	123.5
Total	135.0	159.0
Forecast depreciation	171.9	181.1
Actual depreciation	163.3	166.9
Total expenditure (forecast)	322.8	335.7
Total expenditure (actual)	298.3	325.9
Customer contributions		
Forecast	16.8	17.1
Actual	16.9	19.9
Capital expenditure		
Forecast	255.0	234.0
Actual	235.0	312.8
Fixed assets		
Forecast	2,707.6	2,817.4
Actual	2,640.7	2,801.7
Energy Sales (million MWh)		
Actual	12.3	12.5
Number of customers		
Actual	574,259	584,878

Table B2: Revenue – Ergon Energy (\$ million (nominal))

Revenue source	Ergon Energy	
	2001-02	2002-03
Income from sales		
Network services	443.9	475.5
Public lighting	Not separately identified	
Other	131.9	145.7
Total	575.8	621.2
Capital contributions	16.9	19.9
Proceeds from sale of assets	1.5	4.8*
Other revenue	-	15.0
Total	594.2	660.9

* Book value of assets sold by Ergon Energy equals \$4.0 million.