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**Financial and Service Quality  
Performance 2006-07**

**Ergon Energy**

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*March 2008*

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## TABLE OF CONTENTS

	PAGE
<b>1. INTRODUCTION AND SUMMARY</b>	<b>1</b>
1.1 General Operating Background	1
<i>Network Characteristics</i>	<i>1</i>
1.2 Ergon Energy Customer Profile	2
1.3 Summary of Ergon Energy Financial Performance	3
1.4 Summary of Ergon Energy Service Quality Performance	4
<b>2. FINANCIAL PERFORMANCE</b>	<b>6</b>
2.1 Revenue	6
<i>Under-/Over-Recovery of Distribution Revenue</i>	<i>6</i>
<i>Under-/Over-Recovery of Transmission Use of System (TUOS) Charges</i>	<i>7</i>
2.2 Operating and Maintenance Expenditure	8
2.3 Capital Expenditure	9
<b>3. SERVICE QUALITY PERFORMANCE</b>	<b>11</b>
3.1 Reliability Measures	11
<i>Quarter by Quarter Reliability</i>	<i>13</i>
<i>Reliability of Worst Performing Feeders</i>	<i>13</i>
3.2 Quality of Supply Measures	14
3.3 Customer Service Measures	16
<b>APPENDIX A</b>	<b>22</b>

## 1. INTRODUCTION AND SUMMARY

In the Authority's 2001 & 2005 Determinations on the Regulation of Electricity Distribution, the Authority required the Queensland Distribution Network Service Providers (DNSPs) to provide annual information on their financial and service quality performance.

This report provides an assessment of the financial performance of Ergon Energy for 2006-07, including a comparison with the financial forecasts that were included in the Authority's 2005 Determination and comparisons with the past financial performance of Ergon Energy.

The financial information for 2006-07 was submitted in accordance with the Authority's *Electricity Distribution: Regulatory Reporting Guideline* and the DNSPs' approved Cost Allocation Guidelines.

The Authority's *Electricity Distribution: Service Quality Reporting Guidelines* require the 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 did not commence publicly releasing the reports until the issue of the September quarter 2002 reports due to concerns about the robustness of the data.

The Authority released revised Guidelines in August 2005 in order to improve the reporting of the DNSPs service quality performance. In some instances, this will mean that data provided since 1 July 2005 can not be reliably compared to past data.

This report draws on data from both the annual and quarterly service quality reports, primarily for 2006-07, but also from the three preceding financial years.

### 1.1 General Operating Background

There are currently two main DNSPs operating in Queensland, Energex and Ergon Energy<sup>1</sup>. Both distribution entities are owned by the Queensland Government and until recently had legally separate but wholly owned subsidiary retailing operations. Energex's retailing operations and a portion of Ergon Energy's retailing operations were sold by the Government during 2006-07, with Ergon Energy retaining only certain franchise customers.

#### *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 identifies the key characteristics of each network, and illustrates the differences between the two networks. A key difference is customer density. Specifically, while there are 24.9 customers per kilometre of line in Energex's network, Ergon Energy has just 5.2 customers per kilometre of line in its network.

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

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<sup>1</sup> Country Energy (NSW) operates a franchise network on the Queensland/New South Wales border extending into Queensland and Okey Creek Coal and Anglo Coal (Capcoal Management) operate very small networks confined to their respective mine sites.

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As a result, the service quality measures collected by the Authority are not intended to provide a comparison of the two DNSPs one with the other. It is to be expected that the distributors' performances will vary significantly on a number of service quality measures.

**Table 1: Network characteristics - 2006-07**

<i>Characteristics</i>	<i>Energex</i>	<i>Ergon Energy</i>
Network service area (sq km)	25,256	1,698,100
Number of customers <sup>a</sup>	1,248,510	753,668
Energy delivered (GWh)	20,758	14,507
Energy delivered per customer (MWh)	16.6	19.2
Kilometres of line	50,217	145,631
Customers per km of line	24.9	5.2
Maximum demand of network (MVA)	4,432	2,655
Number of distribution transformers	42,261	83,736
Asset utilisation (%) <sup>b</sup>	29.3	24.5
Distribution losses (%)	6.65	6.41

<sup>a</sup> These values are reported in the distributors' regulatory reports 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.

<sup>b</sup> Sub-transmission transformer utilisation factor. Electricity throughput, Megawatt hour (MWh), expressed as a percentage of sub-transformer capacity (MVA) multiplied by the number of hours per year.

## 1.2 Ergon Energy Customer Profile

Ergon Energy's customers 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* – those who pay averaged charges. The standard asset customer group includes customers with an average consumption of up to 100MWh per year.

**Table 2: Ergon Energy customer numbers and units sold – 2006-07**

<i>Customer type</i>	<i>Customers</i>		<i>Units sold</i>		<i>Units sold per customer</i>	
	<i>Number</i>	<i>Percentage change from previous year</i>	<i>MWh</i>	<i>Percentage change from previous year</i>	<i>MWh/customer</i>	<i>Percentage change from previous year</i>
Individually calculated customers	49	6.5	3,778,246	0.5	77,107.1	(5.6)
Connection asset customers	63	6.8	590,497	3.1	9,373.0	(3.4)
Standard asset customers (consuming 100-4,000MWh pa)	822	19.3	506,619	6.6	616.3	(10.7)
Standard asset customers (consuming <100MWh pa)	635,062	2.7	8,633,615	0.2	13.6	(2.2)
Public street lighting	117,660	0.2	67,463	2.7	0.6	-
Embedded generators	12	50.0	-	-	-	-
Total	753,668	2.3	13,576,440	0.7	18.0	(1.6)

The number of customers grew moderately in 2006-07, falling below 3 per cent growth for the first time in four years. The number of small customers, which account for the majority of Ergon Energy's customer base, grew 2.7 per cent during the year. Energy sales increased 0.7 per cent in the year following a 4.1 per cent increase in 2005-06.

### 1.3 Summary of Ergon Energy Financial Performance

Ergon Energy's actual revenue in 2006-07 was less than that allowed by the Authority in the 2005 Final Determination.

Ergon Energy under-recovered its 2006-07 Aggregate Annual Revenue Requirement (AARR), including capital contributions and revenue from the use of regulated assets by other Ergon Energy entities, by \$4.9 million in 2006-07 (see Table 3). However, Ergon Energy exceeded its 2005-06 AARR by \$18.7 million and the Authority had previously decided to delay returning this revenue to customers until 2008-09 as Ergon Energy was already scheduled to return over-recovered revenue from 2004-05 to customers in 2007-08. The net result is that, after adjustment to 2008-09 values, Ergon Energy is required to return \$18.1 million to customers in 2008-09.

A summary of Ergon Energy's financial performance in 2006-07 is provided in Table 3.

**Table 3: Ergon Energy financial performance - 2006-07 (\$ nominal)**

	<i>Actual</i> <i>2005-06</i> <i>(\$ mill)</i>	<i>Actual</i> <i>2006-07</i> <i>(\$ mill)</i>	<i>Forecast</i> <i>2006-07</i> <i>(\$ mill)</i>	<i>Variance from forecast</i> <i>2006-07</i>	
				<i>(\$ mill)</i>	<i>(%)</i>
Aggregate Annual Revenue Requirement	730.8	740.6	745.5	(4.9)	(0.7)
Revenue from services*	690.1	697.3	701.6	(4.3)	(0.6)
Capital contributions	36.2	42.0	35.9	6.1	17.0
Revenue from outside use of regulated assets	4.5	1.3	8.0	(6.7)	(83.8)
Operating and maintenance expenditure	283.7	292.5	279.6	12.9	4.6
<b>Capital expenditure</b>	<b>623.2</b>	<b>735.5</b>	<b>574.4</b>	<b>161.1</b>	<b>28.0</b>

\* *Includes network and non-network services*

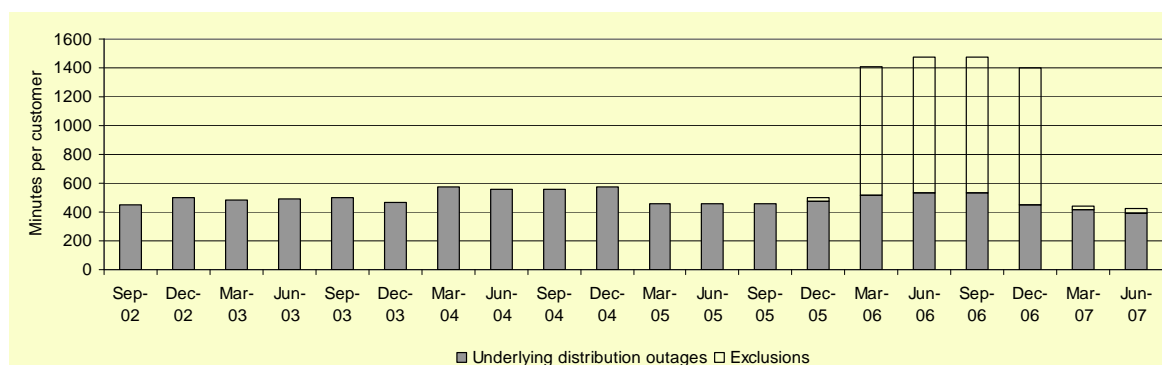
In its 2005 Final Determination, the Authority estimated the level of operating costs and capital expenditure required to deliver prescribed distribution services for each year of the regulatory period for each DNSP. While estimates were provided for each year of the regulatory period, actual annual operating and capital expenditure are likely to vary from those estimates in response to a range of external circumstances and operational requirements not foreseen at the time estimates are made.

Ergon Energy's operating and maintenance expenditure of \$292.5 million in 2006-07 was \$12.9 million (4.6 per cent) higher than forecast. Ergon Energy attributed the higher than forecast operating and maintenance expenditure in 2006-07 to increases in costs associated with inspection and vegetation management and costs due to the introduction of full retail competition (FRC).

Capital expenditure was \$161.1 million (28 per cent) higher than forecast during 2006-07 and \$112.3 million (18 per cent) higher than the previous year. Higher than forecast capital expenditure in 2006-07 was driven by demand related expenditure and significantly higher expenditure on non-system assets. The increase also reflects a continued focus by Ergon Energy on improving its network performance in response to the Government's Electricity Distribution and Service Delivery (EDSD) Review, which reported in July 2004.

#### **1.4 Summary of Ergon Energy Service Quality Performance**

During 2006-07, Ergon Energy customers on average experienced 3.4 distribution-related interruptions leaving them without power for a total of 422 minutes. This result is shown in Figure 1. The high level of exclusions for 2006 was the result of Cyclone Larry in March 2006 with the quarterly results presented in Figure 1 based on a 12-month rolling average.

**Figure 1: Average duration of outages per customer for the 12 months to end of quarter**

The total number of technical quality of supply complaints received by Ergon Energy decreased from 2,821 in 2005-06 to 2,240 in 2006-07. The main areas of complaints in 2006-07 related to low supply voltage, which can cause light dimming and motor starting problems, minor voltage dips, which can cause flickering lights, and noise from appliances or lights.

However, the average time taken to investigate and resolve quality of supply complaints rose marginally from 72 days in the June quarter 2006 to 76 days in the June quarter 2007.

Ergon Energy's performance against a range of customer service measures generally improved during 2006-07:

- the length of time that customers had to wait to speak to an operator when calling the call centre came down overall during 2006-07 from 39 seconds in the June quarter 2006 to 27 seconds in the June quarter 2007.
- the percentage of calls abandoned fell from 3.2 per cent in the June quarter 2006 to 2.2 per cent in the June quarter 2007.
- the number of Guaranteed Service Level (GSL) payments and the amounts paid for GSLs both displayed a general decreasing trend during 2006-07. The total number of GSL payments fell from 696 in 2005-06 to 441 in 2006-07, while the total amount of GSL payments fell from \$45,500 in 2005-06 to \$32,590 in 2006-07.

## 2. FINANCIAL PERFORMANCE

This section summarises the financial performance of the revenue cap regulated business segment of Ergon Energy. The information is for the year ended 30 June 2007. The data used in the analysis has been drawn mainly from Ergon Energy's audited Regulatory Reporting Statements. These accounts were submitted in accordance with the Authority's *Electricity Distribution: Regulatory Reporting Guidelines*.

Areas of particular interest concerning Ergon Energy's overall financial performance are 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 2005 Final Determination and the previous year's actual data are presented below. Detailed financial data tables for Ergon Energy are provided at Appendix A.

### 2.1 Revenue

#### *Under-/Over-Recovery of Distribution Revenue*

In the 2005 Final Determination, the Authority set a maximum revenue cap for each of the five years of the 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 and maintenance expenditure incurred in the delivery of prescribed distribution services.

The 2005 Final Determination revenue cap calculations included both Distribution Use of System (DUOS) Services and some non-DUOS services. These non-DUOS services include prescribed distribution services, such as temporary builders' services, that are related to the operation and use of the distribution system. These services typically account for less than 5 per cent of total services revenue. In the Authority's 2001 Final Determination, non-DUOS services were dealt with separately from the revenue cap calculations.

In its 2005 Final Determination, the Authority accepted Ergon Energy's proposed treatment of shared assets – regulated assets that are utilised by both the regulated and non-regulated businesses within Ergon Energy. Ergon Energy proposed to include these shared assets in the regulated asset base, as they are owned by the regulated business, but to then charge non-regulated parts of the business the full costs of their use of those assets<sup>2</sup>. The Authority approved this approach in its 2005 Final Determination but included a provision for any differences between forecast and actual revenue from the outside use of regulated assets to be subject to an unders and overs process on an annual basis.

The Authority's 2005 Final Determination uses an "unders and overs" account for each DNSP to ensure compliance with the annual revenue caps. 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 (see Table 4).

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<sup>2</sup> In the case of Energex, the shared asset portion of assets utilised by the regulated distribution services was identified and only that portion was included in the regulated asset base. The Energex and Ergon Energy approaches yield the same outcome ensuring that customers of the regulated business are not subsidising the provision of unregulated services.

**Table 4: Ergon Energy Aggregate Annual Revenue Requirement – 2006-07**

	<i>\$ million (nominal)</i>
Actual revenue earned during 2006-07	
Revenue from services	697.3
Revenue from capital contributions	42.0
Revenue from outside use of regulated assets	<u>1.3</u>
Total	<u>740.6</u>
<i>less</i> Allowable annual revenue	
Revenue from services	701.6
Revenue from capital contributions	35.9
Revenue from outside use of regulated assets	<u>8.0</u>
Total	<u>745.5</u>
<b>Under-recovery of AARR for 2006-07</b>	<b>4.9</b>

Table 4 shows that Ergon Energy under-recovered its 2006-07 AARR by \$4.9 million (or \$5.8 million in 2008-09 dollars). This was comprised of:

- \$4.3 million less than forecast from the provision of services;
- \$6.7 million less than forecast from the use of regulated assets by other Ergon Energy entities; offset by
- \$6.1 million more than forecast from capital contributions.

Ergon Energy exceeded its 2005-06 AARR by \$18.7 million (or \$23.9 million in 2008-09 dollars). However, the Authority allowed Ergon Energy to return this over-recovered revenue to customers in 2008-09 as Ergon Energy was already scheduled to return over-recovered revenue from 2004-05 to customers in 2007-08.

The net result of these two adjustments is that, after adjustment to 2008-09 dollars, Ergon Energy is required to return \$18.1 million to customers in 2008-09.

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

TUOS charges are calculated by the distributors each year to pass-through to distribution customers the cost levied for the use of the transmission system. These costs primarily reflect Powerlink charges and payments to embedded generators. Electricity transmission charges are regulated by the Australian Energy Regulator (AER) and paid to Powerlink by distributors on behalf of customers.

The connection of an embedded generator to a distribution network reduces the amount of energy drawn from the transmission network. This in turn reduces the TUOS charge that the distributor has to pay the transmission network owner. However, the distributor passes through the full amount of these avoided TUOS payments to the embedded generator whose connection led to the reduction in TUOS payable.

The Authority approves TUOS charges, to be levied by the distributors, that allow them to recover the TUOS charges they have paid to Powerlink and avoided TUOS payments to embedded generators. Any difference between TUOS revenue recovered by distributors from

customers and the charges they pay to Powerlink and embedded generators is recouped from, or returned to, customers through future charges.

Ergon Energy's 2006-07 TUOS charges are provided in Table 5.

**Table 5: Ergon Energy's TUOS Unders and Overs Account – 2006-07**

	<i>\$ million (nominal)</i>
TUOS charged by Powerlink	164.4
<i>plus</i> TUOS charged by Embedded Generators	2.9
<i>equals</i> Total TUOS charged	167.3
<i>less</i> actual TUOS revenue earned during 2006-07	166.5
<i>equals</i> <b>Under-recovery for 2006-07</b>	<b>0.8</b>

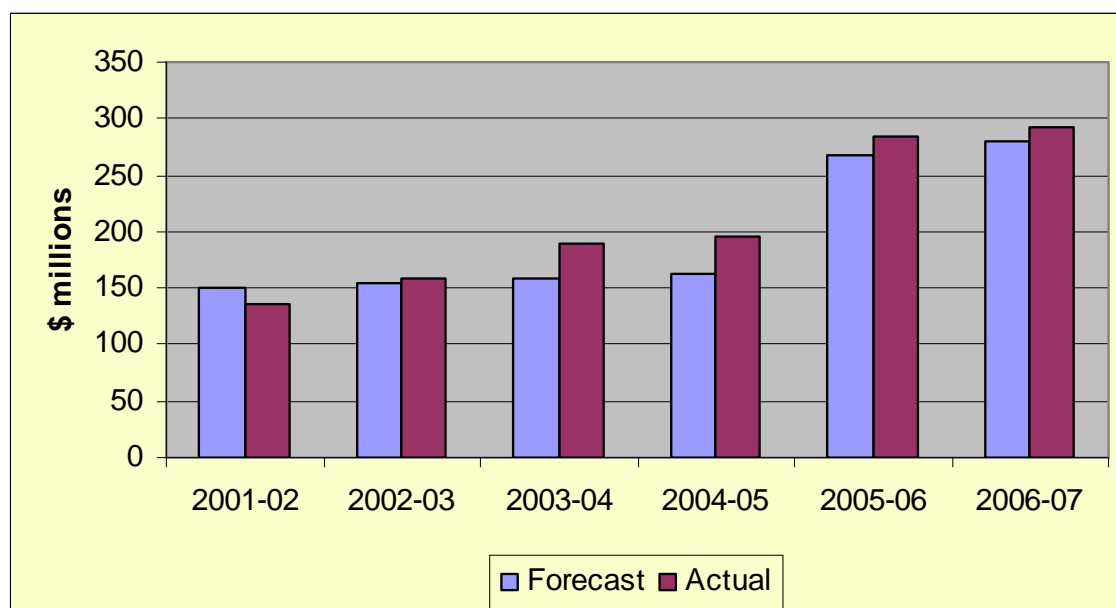
Table 5 indicates that TUOS charges to customers were less than TUOS payments to Powerlink and embedded generators by \$0.8 million during 2006-07. Ergon Energy will be allowed to recoup this under-recovery from customers as part of its 2008-09 TUOS charges.

## 2.2 Operating and Maintenance Expenditure

The regulatory framework is designed to give the distribution businesses an incentive to increase their forecast return by improving operating efficiency. To this end, the distributors retain the benefit of any efficiency gain for the remainder of the regulatory period.

Figure 2 shows network operating and maintenance expenditure reported by Ergon Energy for 2001-02 to 2006-07, compared with the forecast operating and maintenance expenditure in the 2001 and 2005 Final Determinations.

**Figure 2: Ergon Energy operating and maintenance expenditure – 2001-02 to 2006-07**

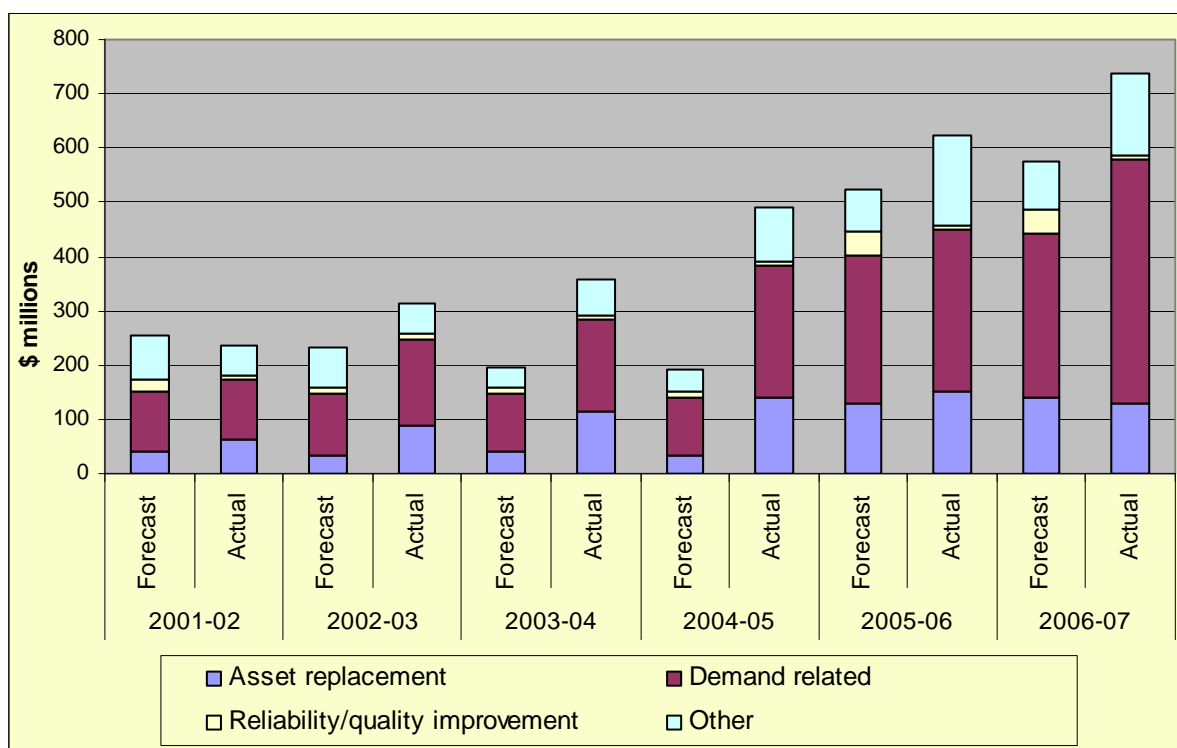


Ergon Energy's operating and maintenance expenditure in 2005-06 was \$12.9 million (4.6 per cent) higher than forecast due in part to costs associated with FRC (\$4.3 million). The increase in expenditure reflected a number of factors, including increases in inspection and vegetation management costs. These increased costs were partially offset by a reduction in emergency response expenditure, which had been unusually high in 2005-06 due to Cyclone Larry. The higher expenditure over the last two years also reflects Ergon Energy's response to the Government's EDSD Review, which reported in July 2004.

### 2.3 Capital Expenditure

Figure 3 shows network capital expenditure in aggregate and by purpose reported by Ergon Energy for 2001-02 to 2006-07, compared with the forecast capital expenditure included in the 2001 and 2005 Final Determinations.

**Figure 3: Ergon Energy capital expenditure – 2001-02 to 2006-07**



Significant growth in expenditure over the last three years largely reflects Ergon Energy's response to the Government's EDSD Review, which found there had been under investment in Ergon Energy's network for an extended period of time.

Capital expenditure was \$161.1 million (28 per cent) higher than forecast during 2006-07. The higher capital expenditure reflected the following factors:

- an increase in customer initiated expenditure, expenditure specifically requested by a customer to meet changed demand as opposed to augmentation related expenditure which is generally initiated by the distributor to meet general demand changes, due to strong population growth, as well as ongoing demand from major customer projects (for example, upgrades to SunWater infrastructure at a cost of about \$30 million); and
- expenditure on non-system assets that was 85.6 per cent higher than forecast, including increased expenditure on motor vehicles, land and buildings and computer systems.

Motor vehicle expenditure of \$28.0 million was 9 per cent more than forecast (\$25.7 million), land and buildings expenditure of \$35.7 million was more than double that forecast (\$16.9 million) and computer systems of \$36.0 million was almost four times that forecast (\$9.7 million). Ergon Energy attributed the increased expenditure primarily to increased resources required to support the expanded program of capital works

In addition, expenditure of \$20.4 million was incurred on non-system assets in relation to Project JET, a joint initiative of both Ergon Energy and Energex aimed at combining and integrating a number of administrative functions such as Asset Management, Works Management, Human Resources and Payroll, Finance, Health, Safety and Environment and Logistics.

### 3. SERVICE QUALITY PERFORMANCE

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 2007 and is drawn from Ergon Energy’s quarterly and annual service quality reports for 2006-07. These reports were submitted in accordance with the Authority’s *Electricity Distribution: Service Quality Reporting Guidelines (Version 2.0)*.

The Authority commenced posting service quality reports provided by the DNSPs on its website with the September quarter 2002 reports (released February 2003). Due to the improved reporting requirements for service quality data incorporated in Version 2.0 of the Guidelines, historical information (prior to 1 July 2005) for some measures may not be directly comparable with more recent information.

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.

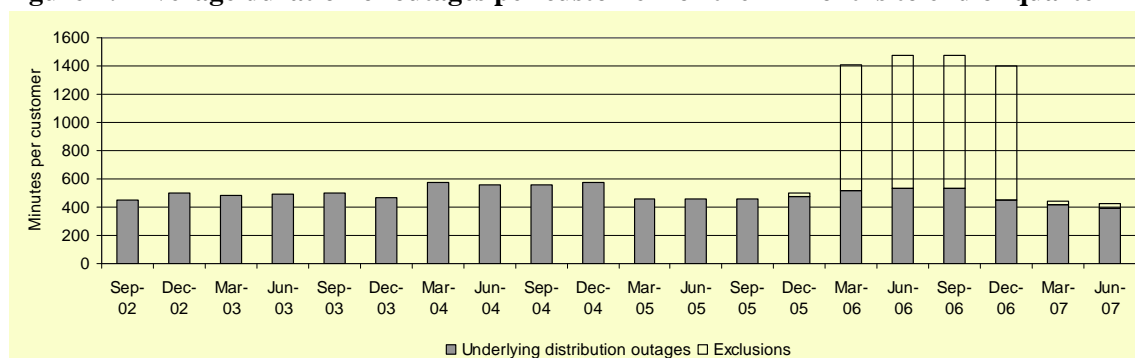
Quality of supply measures are intended to indicate problems with the nature of electricity supply, such as low or high voltage levels, based on customers reporting symptoms that are typically associated with such problems. For example, low supply voltage would be evidenced by complaints relating to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

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

#### 3.1 Reliability Measures

During 2006-07, Ergon Energy customers on average experienced 3.4 distribution-related interruptions leaving them without power for a total of 422 minutes. This result is shown in Figure 4. The high level of exclusions for 2006 was the result of Cyclone Larry in March 2006 with the quarterly results presented in Figure 4 based on a 12 month rolling average.

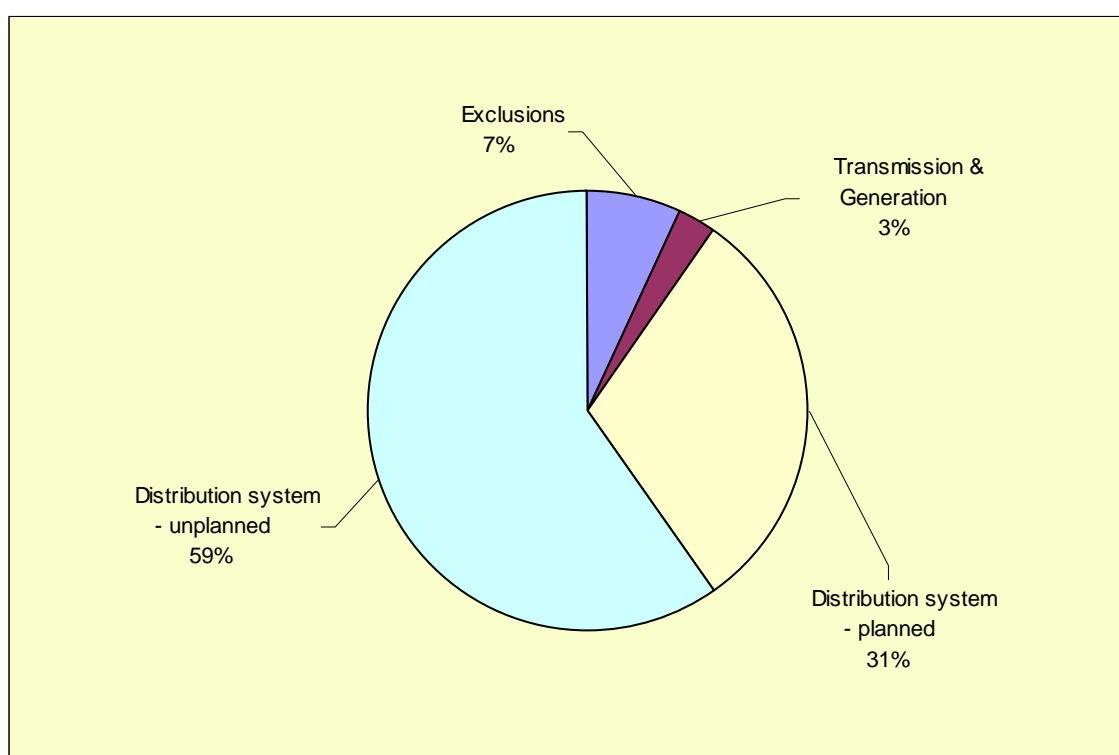
**Figure 4: Average duration of outages per customer for the 12 months to end of quarter**



Unplanned interruptions arising in the distribution network, of which excluded weather-related events are a sub-component, accounted for most (66 per cent) of the average 422 minutes that Ergon Energy customers were without electricity supply during 2006-07, as shown in Figure 5. Planned interruptions in the distribution network accounted for 31 per cent of outages while transmission and generation interruptions accounted for the remainder. Exclusions contributed 7 per cent of the outages during 2006-07.

In contrast, in 2005-06, unplanned interruptions accounted for 90 per cent of the total 1,483 minutes that Ergon Energy customers were, on average, without electricity supply. Planned interruptions in the distribution network accounted for 9 per cent of outages while transmission and generation interruptions accounted for the remaining balance. As noted above, the effects of Cyclone Larry were reflected in the 2005-06 results.

**Figure 5: Ergon Energy duration of interruptions during 2006-07, by source**



Interruptions arising in the distribution network can be disaggregated according to geographic categories – that is, Urban, Short Rural and Long Rural.<sup>3</sup> As shown in Table 6, there were significant differences in the level of reliability across Ergon Energy’s network during 2006-07. Customers in all geographic categories experienced a decrease in the duration of interruptions. However, the magnitude of the decreases varied with urban and short rural areas experiencing decreases of 45.9 minutes and 143.4 minutes respectively from the June quarter 2006 to the June quarter 2007, while the period of time that customers in the long rural areas were without supply decreased by 372 minutes over the same period from a very high level of 1,332 minutes.

<sup>3</sup> Ergon Energy does not have any feeders that meet the definition of CBD.

**Table 6: Ergon Energy duration of distribution-related interruptions by network type (minutes) after removal of excluded events for the 12 months to end of quarter**

	<i>JUN 2006</i>	<i>SEP 2006</i>	<i>DEC 2006</i>	<i>MAR 2007</i>	<i>JUN 2007</i>
Total distribution system	532.0	531.8	454.1	412.7	392.7
Urban	219.0	223.5	194.7	177.4	173.1
Short Rural	594.4	606.5	531.1	481.8	451.0
Long Rural	1332.0	1342.3	1092.4	996.9	960.0

*Quarter by Quarter Reliability*

As shown in Table 7, Ergon Energy's performance was significantly worse during the December and March quarters (the storm season). While the removal of excluded events smooths these variations in reliability performance between quarters, it does not entirely remove seasonal fluctuations.

**Table 7: Ergon Energy average number and duration of distribution-related interruptions per customer**

	<i>SEP 2006</i>	<i>DEC 2006</i>	<i>MAR 2007</i>	<i>JUN 2007</i>
Average number of interruptions per customer (SAIFI) <b>before</b> excluded events	0.69	1.24	0.95	0.57
Average number of interruptions per customer (SAIFI) <b>after</b> excluded events	0.69	1.06	0.95	0.57
Average duration of each interruption (CAIDI) <b>before</b> excluded events - minutes	124.72	117.59	126.33	125.20
Average duration of each interruption (CAIDI) <b>after</b> excluded events - minutes	124.72	108.40	126.33	125.20
Duration of all interruptions per customer (SAIDI) <b>before</b> excluded events – minutes	85.63	145.76	120.42	71.37
Duration of all interruptions per customer (SAIDI) <b>after</b> excluded events – minutes	85.63	114.77	120.42	71.37

*Reliability of Worst Performing Feeders*

As shown in Table 8, the reliability of Ergon Energy's worst performing feeders generally improved in 2006-07 compared to 2005-06. It is likely that the improvement partly reflects the fact that Cyclone Larry affected the 2005-06 results.

**Table 8: Ergon Energy range of average number and duration of distribution-related interruptions per customer for 10 worst performing feeders**

	2002-03	2003-04	2004-05	2005-06	2006-07
Average number of interruptions per customer (SAIFI) <b>before</b> excluded events					
Urban	2.0 – 13.0	1.1 – 13.7	4.0 – 12.0	5.0 - 25.3	1.0 - 13.3
Short Rural	11.2 – 24.7	5.2 - 36.6	7.0 - 17.8	15.1 - 32.5	5.0 - 16.2
Long Rural	11.8 – 37.1	11.1 - 34.2	7.3 - 19.7	11.0 – 29.4	6.6 - 18.0
Duration of all interruptions per customer (SAIDI) <b>before</b> excluded events – hours					
Urban	16.3 – 36.1	18.2 – 43.8	15.7 – 39.6	18.4 – 78.7	15.9 - 99.2
Short Rural	55.0 – 81.2	60.6 – 91.6	52.5 - 76	65.5 – 110.2	46.8 - 134.6
Long Rural	46.4 – 111.4	55.7 – 86.9	54.7 - 97	63.6 – 165.9	50.8 - 103.4

In 2006-07, Ergon Energy's 10 worst performing urban feeders supplied electricity to 149 customers, equivalent to 0.06 per cent of Ergon Energy's urban customer base. On average, these customers experienced between 1.0 and 13.3 distribution-related interruptions, without adjusting the data for exclusions, leaving them without power for between 15.9 hours and 99.2 hours. Four of the worst performing urban feeders in 2006-07 were among the 10 worst performing urban feeders for 2005-06.

In 2006-07, Ergon Energy's 10 worst performing short rural feeders supplied electricity to 509 customers, equivalent to 0.2 per cent of Ergon Energy's short rural customer base. On average, these customers experienced between 5.0 and 16.2 distribution-related interruptions, without adjusting the data for exclusions, leaving them without power for between 46.8 hours and 134.6 hours. Only one of the worst performing short rural feeders in 2006-07 was among the 10 worst performing short rural feeders for 2005-06.

In 2006-07, Ergon Energy's 10 worst performing long rural feeders supplied electricity to 1,326 customers, equivalent to 2 per cent of Ergon Energy's long rural customer base. On average, these customers experienced between 6.6 and 18.0 distribution-related interruptions, without adjusting the data for exclusions, leaving them without power for between 50.8 hours and 103.4 hours. Two of the worst performing long rural feeders in 2006-07 were among the 10 worst performing long rural feeders for 2005-06.

### 3.2 Quality of Supply Measures

The total number of technical quality of supply complaints received by Ergon Energy decreased from 2,821 in 2005-06 to 2,240 in 2006-07. Complaints over low supply voltage, which can cause light dimming and motor starting problems, minor voltage dips and noise from appliances or lights were the most common types of complaints, as shown in Table 9.

**Table 9: Ergon Energy quality of supply complaints – categorised according to symptoms**

	<i>SEP 2006</i>	<i>DEC 2006</i>	<i>MAR 2007</i>	<i>JUN 2007</i>	<i>TOTAL</i>
Total quality of supply complaints	489	598	620	533	2240
Low supply voltage	164	208	219	164	755
Other complaints	53	50	41	48	192
Voltage swell	14	15	33	26	88
Voltage dips –minor	115	115	109	132	471
TV or radio interference	8	20	30	25	83
Waveform distortion or unbalance	23	22	24	21	90
Voltage dips – severe	25	52	40	23	140
Voltage spike	4	3	1	6	14
Noises from appliances or lights	83	113	123	88	407

The average time taken to investigate and resolve quality of supply complaints rose marginally from 72 days in the June quarter 2006 to 76 days in the June quarter 2007.

As shown in Table 10, the higher number of quality of supply complaints in 2006-07 was caused by network restrictions or events, recording a total of 761 complaints.

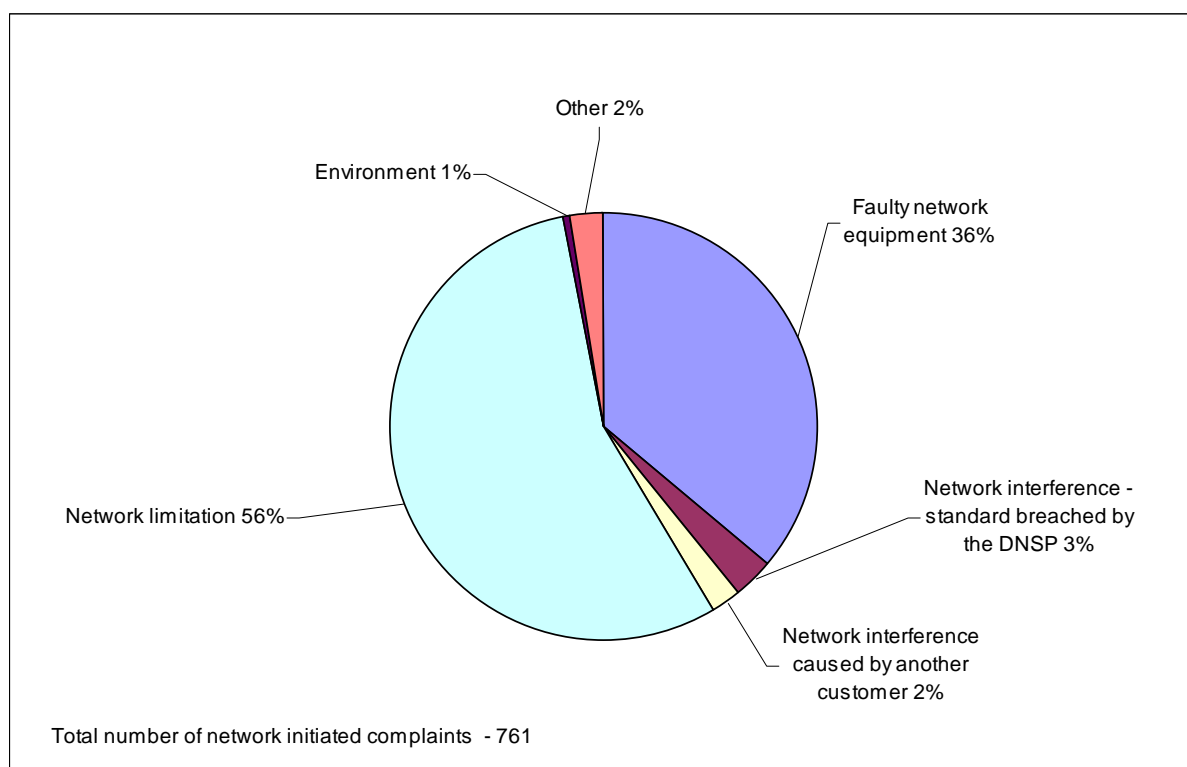
Historical comparisons on the possible causes of quality of supply complaints is complicated by the improvements in collecting data that were made by Ergon Energy in the March quarter 2004. This likely explains most of the increase in these numbers from 2003-04. Prior to the March quarter 2004, possible causes of quality of supply complaints and the number of complaints were reported in two different databases instead of one. The number of possible causes of quality of supply complaints was based on the number of jobs undertaken as a result of complaints and did not take into account the number of complaints which may have related to any single job.

**Table 10: Ergon Energy quality of supply complaints – possible causes**

	<i>2003-04</i>	<i>2004-05</i>	<i>2005-06</i>	<i>2006-07</i>
Network initiated quality of supply complaints	795	859	769	761
Quality of supply complaints initiated on the customer side of the meter	46	255	170	170
Quality of supply complaints for which no cause was found	187	803	761	200

*Note – the summation of the above categories of possible causes for quality of supply complaints does not equal the total of the four quarterly quality of supply complaints as listed in Table 9 due to the removal of possible double entries and misclassified complaints.*

As shown in Figure 6, network-initiated complaints are further broken down into sub-categories, of which faulty network equipment and network limitations accounted for 36 per cent and 56 per cent of total network-initiated complaints respectively. Interference to the network arising from the operation of equipment by customers and ‘other’ unclassified complaints explained most of the remaining quality of supply complaints.

**Figure 6: Ergon Energy – causes of network initiated quality of supply complaints**

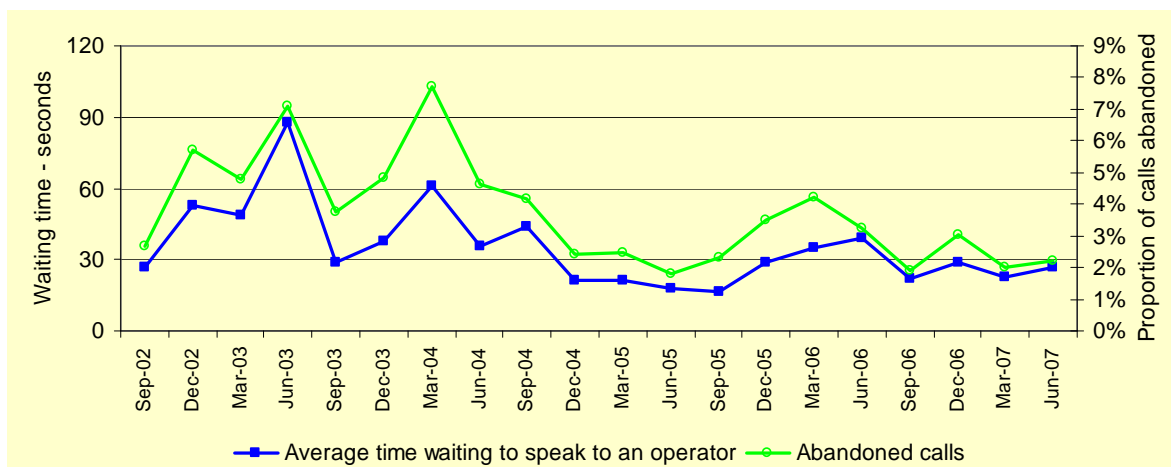
### 3.3 Customer Service Measures

Ergon Energy's performance largely improved against a range of customer service measures during 2006-07.

As shown in Figure 7, the length of time that customers had to wait to speak to an operator when calling the call centre decreased overall during 2006-07 from 39 seconds in the June quarter 2006 to 27 seconds in the June quarter 2007. This measure has shown a general improvement over the years, excepting a few 'blips' in the data related to the severe storms and outages that placed significant pressure on the call centre at those times.

The percentage of calls abandoned also decreased from 3.2 per cent in the June quarter 2006 to 2.2 per cent in the June quarter 2007. This measure has shown a general improvement over the years, with a pattern of results similar to that observed for the results for the length of time waiting to speak to an operator.

**Figure 7: Ergon Energy average time waiting to speak to an operator & abandoned calls**



As shown in Table 11, the number of complaints that Ergon Energy received regarding the reliability of supply was volatile in 2006-07. The number of reliability complaints is typically higher in the storm season quarters (December and March). While the June quarter 2006 recorded the second largest number of complaints Ergon Energy was unable to explain this unusual result. In total, the number of reliability of supply complaints in 2006-07 of 1,233 complaints was almost identical to last year’s total of 1,237 complaints.

A new requirement of the Authority’s revised Service Quality Reporting Guidelines is the inclusion of complaints relating to momentary interruptions to supply as a sub-category of reliability complaints. Ergon Energy was unable to separately identify such complaints in its complaint handling system for the first three quarters of 2006-07. These system issues were finally resolved by the June quarter 2007 with 213 momentary interruption complaints reported in that quarter. Complaints regarding momentary interruptions are included in the total number of reliability complaints.

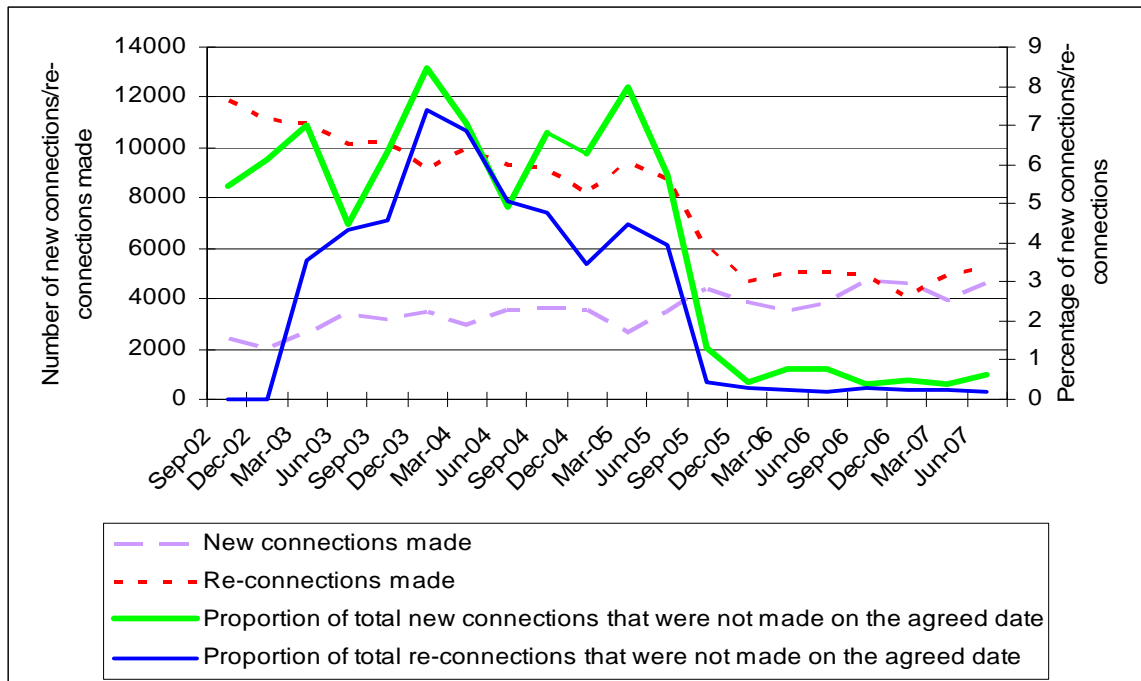
**Table 11: Ergon Energy number of reliability complaints**

	SEP 2006	DEC 2006	MAR 2007	JUN 2007	TOTAL
Number of reliability complaints	194	228	460	351	1,233

As shown in Figure 8, there was decrease in the proportion of total new supply connections that Ergon Energy failed to make by the agreed date in 2006-07 (0.8 per cent in the June quarter 2006 to 0.6 per cent in the June quarter 2007).

The proportion of total re-connections of supply that were not made on the agreed date was unchanged at 0.2 per cent at the end of the June quarter 2007 compared to the end of the June quarter 2006.

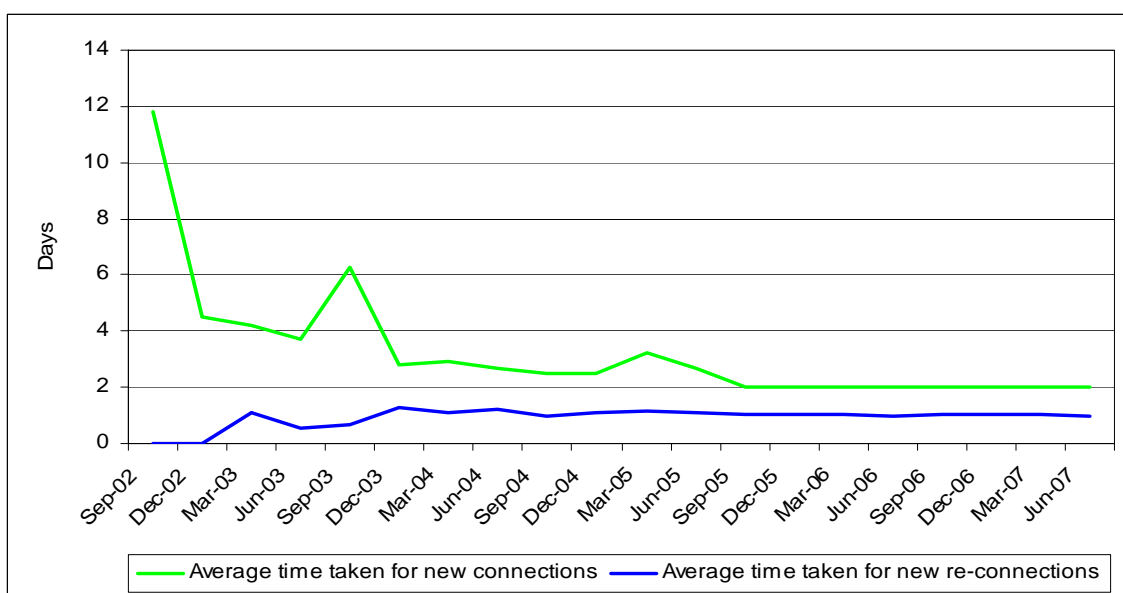
**Figure 8: Ergon Energy number of new and re-connections made, proportion of new and re-connections not made on the agreed date**



As shown in Figure 9, the average length of time that customers had to wait for a new connection to the network remained at a steady rate of two days during 2006-07. The recent performance represented a significant improvement from that achieved at the commencement of reporting under the Guidelines.

The average length of time that customers had to wait for a re-connection to the network has varied little over the last four and a half years, at about one day.

**Figure 9: Ergon Energy average time taken for new connections and re-connections**

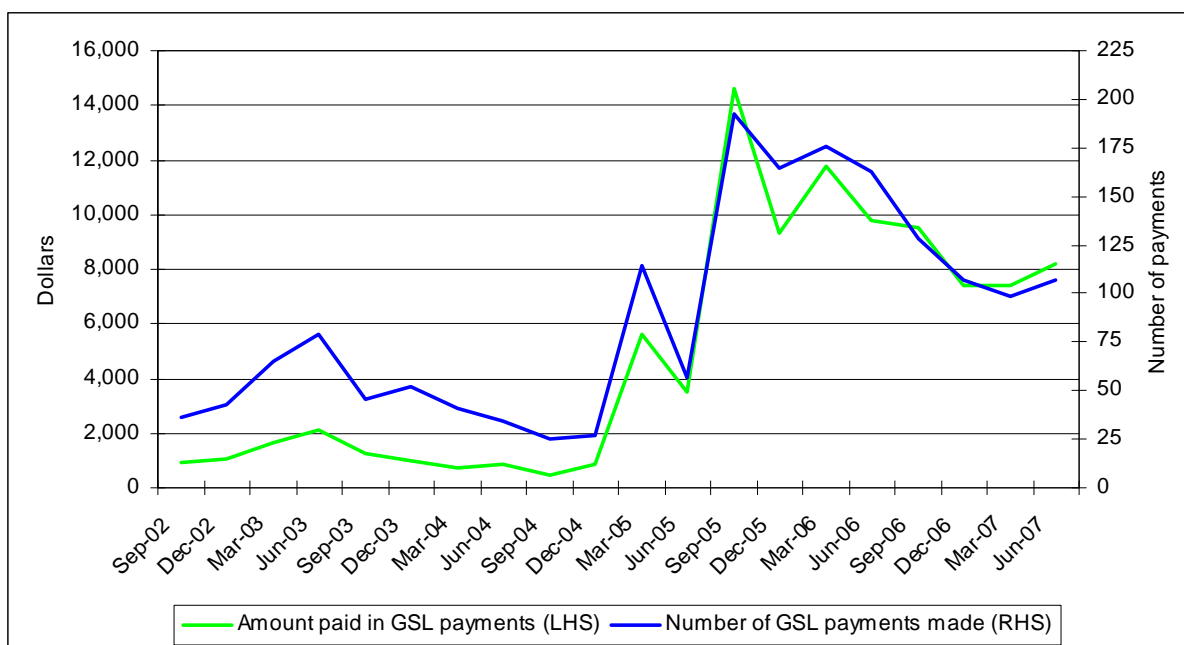


Ergon Energy was unable to provide data on street light performance for much of 2006-07 with only the September quarter 2006 results being reported. Ergon Energy stated that there were a number of limitations arising from the transition to a new reporting system. Accordingly, no analysis is provided of street lighting performance for 2006-07.

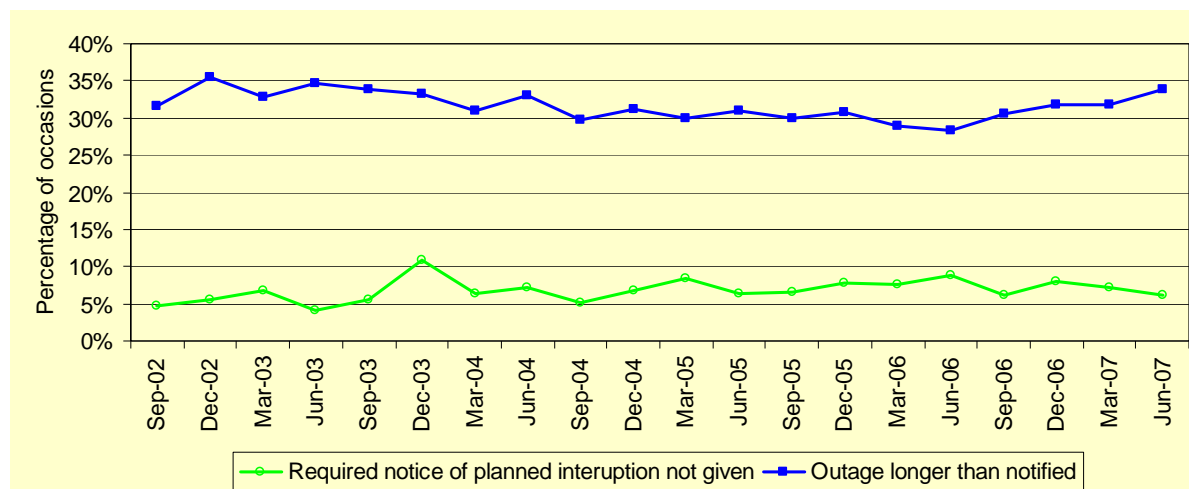
The number of GSL payments per quarter and the amounts paid for GSLs per quarter have both displayed a general decreasing trend since December 2005 (see Figure 10). The total number of GSL payments fell from 696 in 2005-06 to 441 in 2006-07, while the total amount of GSL payments fell from \$45,500 in 2005-06 to \$32,590 in 2006-07.

The rapid increase in quarterly GSL payments during 2005-06 was due to the introduction of a GSL scheme mandated by the Queensland Government from 1 January 2005. Prior to 1 January 2005, GSLs were voluntary payments made by the distributors to customers that reported instances where the distributors had not met self-imposed service quality standards.

**Figure 10: Ergon Energy guaranteed service level payments**



The proportion of occasions on which the required notice of a planned interruption to supply was not given has varied between 5 per cent and 10 per cent over the past five years (see Figure 11). Over the same period, the proportion of occasions on which the duration of a planned interruption exceeded the time specified in the notification has varied between 30 per cent and 35 per cent. This range means that about one in every three planned interruptions exceeded the time specified to customers. This is an important measure of Ergon Energy’s customer service performance given the large number of planned interruptions on its network (see Figure 5).

**Figure 11: Ergon Energy notification of commencement and duration of planned interruptions**

The basis for reporting customer service complaints was changed in the Authority's revised Service Quality Reporting Guidelines (August 2005). As a result, it is not possible to compare results from the September quarter 2005 with earlier results.

As shown in Table 12, complaints about Ergon Energy's customer service were the biggest cause of complaints during 2006-07. Other causes for complaint included trees touching or close to power lines, field activity and meter reading.

**Table 12: Ergon Energy complaint resolution – reasons for complaints**

	SEP 2006	DEC 2006	MAR 2007	JUN 2007	TOTAL
Total number of complaints	695	697	810	799	3001
Customer service	208	162	212	235	817
Trees	142	168	219	198	727
Field activity	149	145	181	138	613
Meter reading	80	88	89	93	350
Supply – new extensions	41	57	59	50	207
Other complaints	34	37	7	46	124
Streetlights	11	14	8	16	49
Infrastructure	15	9	12	10	46
Metering/Technical	6	7	13	12	38
Environmental issues	8	5	10	0	23
Line clearances	1	5	0	1	7
Suspected compliance failure	0	0	0	0	0

The percentage of complaints resolved within 20 days averaged 89.4 per cent during 2006-07. The average time taken to resolve complaints fell from 6.6 days in the June quarter 2006 to 5.1 days in the June quarter 2007.

The number of repeat complaints increased steadily during 2006-07, from seven complaints in the September quarter 2006 (one of the best performances on record) to 21 complaints in the June quarter 2007. However, in total, the number of repeat complaints fell from 86 complaints in 2005-06 to 56 repeat complaints in 2006-07.

The average time taken to resolve repeat complaints fell significantly over 2006-07, from almost 18.4 days in the September quarter 2006 to five days in the June quarter 2007.

## APPENDIX A

## FINANCIAL DATA TABLES – 2001-02 to 2006-07

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

	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07
<b>Revenue</b>						
Forecast sales	447.5	476.05	500.4	523.4	675.2	701.6*
Actual sales	443.9	475.5	505.8	535.8	690.1	697.3*
Forecast revenue from outside use of regulated assets					8.0	8.0
Actual revenue from outside use of regulated assets					4.5	1.3
<b>Expenditure</b>						
Forecast operating and maintenance expenditure	150.9	154.6	158.4	162.4	266.7	279.6
Actual operating and maintenance expenditure						
Operating expenditure	34.6	35.5	42.0	53.0	79.9	77.9
Maintenance expenditure	100.4	123.5	147.5	142.1	203.9	214.6
Total	135.0	159.0	189.5	195.1	283.7	292.5
Forecast depreciation	171.9	181.1	187.7	192.4	231.9	237.4
Actual depreciation	163.3	166.9	173.3	186.4	225.2	221.4
Total expenditure (forecast)	322.8	335.7	346.1	354.8	498.6	517.0
Total expenditure (actual)	298.3	325.9	362.8	381.5	508.9	513.9
<b>Customer contributions</b>						
Forecast	16.8	17.1	17.5	17.9	28.9	35.9
Actual	16.9	19.9	25.4	35.5	36.2	42.0
<b>Capital expenditure</b>						
Forecast	255.0	234.0	194.6	192.3	524.5	574.4
Actual	235.0	312.8	358.2	490.1	623.2	735.5
<b>Fixed assets</b>						
Forecast	2,720.7	2,831.0	2,896.8	2,956.8	4,650.9	5,118.8
Actual	2,501.8	2,661.5	2,961.2	3,321.5	4,690.1	5,279.9
<b>Energy Sales (million MWh)</b>						
Actual	12.3	12.5	12.8	12.9	13.5	13.6
<b>Number of customers</b>						
Actual	574,259	584,878	584,717	711,143	736,710	753,668**

\* Includes network and non-network services

\*\*ErgonEnergy revised their method of recording street lighting customers from 2004-05 onwards.

**Table A2: Revenue – Ergon Energy (\$ million (nominal))**

<i>Revenue source*</i>	<i>2001-02</i>	<i>2002-03</i>	<i>2003-04</i>	<i>2004-05</i>	<i>2005-06</i>	<i>2006-07</i>
Sales						
Network services (excl public lighting)	443.9	475.5	495.3	525.5	670.7	678.5
Public lighting	n/a	n/a	10.5	10.3	13.4	14.3
Total network services	443.9	475.5	505.8	535.8	684.1	692.8
TUOS pass-through	139.0	154.4	150.5	143.9	154.1	166.5
Non Network Services	3.0	2.0	3.8	4.0	6.0	4.5
Total services	585.9	631.9	660.1	683.7	844.2	863.8
Revenue from outside use of regulated assets					4.5	1.3
Capital contributions	16.9	19.9	25.4	35.5	36.2	42.0
Profit from sale of assets	(3.4)	0.8	(15.9)	1.7	(0.7)	3.1
Proceeds from sale of assets	1.5	4.8	5.2	4.2	4.1	5.5
Book value of assets sold	4.9	4.0	4.3	2.5	4.8	2.4
Other revenue	-	15.0	17.7	32.8	6.9	32.6

\* *May not sum due to rounding.*

**Table A3: Operating and maintenance expenditure – Ergon Energy (\$ million (nominal))**

<i>Expenditure*</i>	
Operating expenditure	
Meter reading	11.0
Customer service	11.5
Full retail contestability	4.3
Network operations	25.2
Training	19.0
Other	6.8
Total	71.0
Public street lighting	0
Total operating expenditure	77.8
Network maintenance expenditure	
Inspection	75.3
Maintenance and repair	22.8
Vegetation management	85.0
Emergency Response	23.1
Other	0
Total	206.1
Public street lighting	8.5
Total maintenance expenditure	214.6
<b>Total operating and maintenance expenditure</b>	<b>292.5</b>

\* May not sum due to rounding.

**Table A4: Depreciation - Ergon Energy (\$ million (nominal))**

<i>Asset*</i>	
System Assets:	
overhead sub-transmission lines	21.8
underground sub-transmission lines	1.0
overhead distribution lines	36.0
underground distribution lines	13.1
distribution equipment	2.9
substation bays	11.2
substation establishment	6.6
substation switchgear	2.4
zone transformers	4.6
distribution transformers	23.7
low voltage services	6.9
meters	6.1
communications	3.2
generation assets	0.5
street lighting	4.4
other equipment	0
control centre - SCADA	1.7
land and easements	-
Non-System Assets:	
communications	1.6
IT systems	30.9
office furniture and equipment	0.8
motor vehicles	24.3
plant and equipment	9.7
buildings	7.7
land and easements	-
land improvements	0.2
<b>Total</b>	<b>221.4</b>

\* May not sum due to rounding.

**Table A5: Expected and remaining lives of assets – Ergon Energy**

<i>Asset</i>	<i>Expected weighted average economic life (weighted by ORC) (years)</i>	<i>Weighted average remaining economic life (weighted by ORC) (years)</i>
System Assets:		
overhead sub-transmission lines	48.7	26.9
underground sub-transmission lines	52.1	39.1
overhead distribution lines	49.2	24.2
underground distribution lines	58.8	46.0
distribution equipment	35.0	33.3
substation bays	40.0	22.9
substation establishment	40.0	23.0
substation switchgear	35.0	31.3
zone transformers	40.0	17.4
distribution transformers	35.0	21.2
low voltage services	47.6	24.6
meters	25.0	7.8
communications	17.1	9.8
generation assets	18.9	9.6
street lighting	20.0	10.6
other equipment	40.0	37.8
control centre -SCADA	7.2	3.7
land and easements	n/a	n/a
Non-System Assets:		
communications	7.0	4.5
IT systems	3.1	2.1
office furniture and equipment	7.0	4.3
motor vehicles	9.0	5.0
plant and equipment	8.1	5.1
buildings	35.9	19.3
land and easements	n/a	n/a
land improvements	40.0	35.8

**Table A6: Asset values - Ergon Energy (\$ million (nominal))**

<i>Asset*</i>	
System Assets:	
overhead sub-transmission lines	826.8
underground sub-transmission lines	23.5
overhead distribution lines	1,438.4
underground distribution lines	396.6
distribution equipment	39.9
substation bays	424.2
substation establishment	184.7
substation switchgear	63.1
zone transformers	125.0
distribution transformers	498.5
low voltage services	107.7
meters	58.6
communications	41.1
generation assets	2.3
street lighting	54.1
other equipment	0.1
control centre - SCADA	14.7
land and easements	19.8
Non-System Assets:	
communications	10.0
IT systems	75.7
office furniture and equipment	28.6
motor vehicles	104.0
plant and equipment	45.2
buildings	88.3
land and easements	31.5
land improvements	4.2
<b>Total</b>	<b>4,706.7</b>

\* May not sum due to rounding.

**Table A7: Capital Expenditure and additions - Ergon Energy (\$ million (nominal))**

<i>Capital expenditure*</i>	
System Assets:	
overhead sub-transmission lines	66.8
underground sub-transmission lines	3.4
overhead distribution lines	150.5
underground distribution lines	86.4
distribution equipment	3.6
substation bays	64.8
substation establishment	27.4
substation switchgear	15.1
zone transformers	20.5
distribution transformers	100.2
low voltage services	16.2
meters	11.5
communications	1.8
generation assets	-
street lighting	10.3
other equipment	7.5
control centre - SCADA	11.8
land and easements	0.6
Non-System Assets:	
communications	5.7
IT systems	36.0
office furniture and equipment	2.0
motor vehicles	28.0
plant and equipment	28.4
buildings	25.1
land and easements	10.6
land improvements	1.5
<b>Total</b>	<b>735.5</b>

\* May not sum due to rounding.

**Table A8: Capital expenditure by purpose - Ergon Energy (\$ million (nominal))**

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<i>Capital expenditure</i>	
Asset replacement	130.5
Demand related	447.3
Reliability and quality improvements	10.2
Other	147.6
<b>Total</b>	<b>735.5</b>

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**Table A9: Related party transactions - Ergon Energy (\$ million (nominal))**

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<i>Transaction</i>	
Total value of related party transactions	38.6

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