ACT and NSW Electricity Distribution Network Service Providers

Performance Report for 2009–10

November 2011

AUSTRALIAN ENERGY REGULATOR

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Version	Date	Pages
01.0	16 December 2011	7

Contents

Shortened forms

ACCC	Australian Competition and Consumer Commission
ActewAGL	ActewAGL Distribution
ACT and NSW DNSPs	ActewAGL, Ausgrid, Endeavour Energy, Essential Energy
AER	Australian Energy Regulator
capex	capital expenditure
CPI	consumer price index
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DNSP	distribution network service provider
EBSS	efficiency benefit sharing scheme
GSL	guaranteed service level
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Energy Objective
NER	National Electricity Rules
NSP	network service provider
opex	operating expenditure
RAB	regulatory asset base
RIN	regulatory information notice
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
STPIS	service target performance incentive scheme
Tribunal	Australian Competition Tribunal

Summary

In April 2009 the Australian Energy Regulator (AER) issued its first distribution determinations for the Australian Capital Territory and New South Wales electricity distribution network service providers (DNSPs) for the 2009–14 regulatory control period.

This report reviews the financial and service performance of ActewAGL, Ausgrid (formerly EnergyAustralia), Endeavour Energy (formerly Integral Energy) and Essential Energy (formerly Country Energy) (collectively the DNSPs) for 2009–10.

This report is the AER’s first DNSP performance report prepared under the National Electricity Law (NEL). It reflects the AER’s priorities and objectives for network service provider performance reporting and has been prepared as part of the AER’s network reporting and information strategy. This report promotes the National Electricity Objective by:

- enhancing transparency and increasing DNSP accountability by enabling comparisons between approved forecast expenditure and actual costs

- enhancing effective stakeholder participation in the regulatory process by reducing the information asymmetry between DNSPs and stakeholders.

The DNSPs are required to provide financial and service performance information to the AER each year. The financial information contained in this report was provided to the AER in 2009–10 regulatory accounts by the DNSPs. That information is based on the DNSPs’ previous jurisdictional reporting requirements. The AER intends to seek additional information from DNSPs in the future.[1]

The 2009–10 service performance information in this report is based on the AER’s national service target performance incentive scheme (STPIS). That information is the first service performance information provided by the DNSPs in accordance with the AER’s reporting requirements under that scheme. Information collected during the current regulatory control period will be used to set service targets for the next regulatory control period, commencing 1 July 2014.

Energy delivered, customer numbers and maximum demand

In 2009–10 the actual energy delivered and total customer numbers of the DNSPs generally do not vary significantly from forecasts included in the AER’s 2009 determinations.[2] Ausgrid reported the highest variation from its forecasts of approximately 3 per cent for customer numbers and –1.5 per cent for energy delivered.

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1 During the previous regulatory control period ActewAGL was regulated by the Independent Competition and Regulatory Commission (ICRC) and Ausgrid, Endeavour Energy and Essential Energy were regulated by the Independent Pricing and Regulatory Tribunal (IPART).

2 AER, *Final decision: New South Wales distribution determination 2009–10 to 2013–14*, April 2009 and AER, *Final decision: Australian Capital Territory distribution determination 2009–10 to 2013–14*, April 2009.

The actual maximum demand for 2009–10 reported by the NSW DNSPs was not only lower than forecast for 2009–10 but it was also lower than actual maximum demand for 2008–09.

Table A compares the DNSPs' actual maximum demand, energy delivered and customer numbers against the AER's approved forecasts.

Table A Maximum demand, energy delivered and customer numbers for 2009–10

		ActewAGL	Ausgrid	Endeavour Energy	Essential Energy
Maximum demand (MW)	Forecast	689 (MVA)	6 022	4 179	2 391
	Actual	604	5 609	3 722	2 239
	Difference	–	–413	–457	–152
	Difference (%)	–	–6.9	–10.9	–6.4
Energy delivered (GWh)	Forecast	2 933	27 948	17 373	12 092
	Actual	2 908	27 527	17 410	12 103
	Difference	–25	–421	37	11
	Difference (%)	–0.9	–1.5	0.2	0.1
Customer numbers	Forecast	–	1 559 297	860 392	804 157
	Actual	164 900	1 605 635	866 767	798 356
	Difference	–	46 338	6 375	–5 801
	Difference (%)	–	3.0	0.7	–0.7

Further detail regarding the DNSPs' maximum demand, energy delivered and customer numbers is contained in chapter 2 and appendix B.

Overview of financial performance

This report includes information on the DNSPs' capital expenditure (capex), operating expenditure (opex) and revenue for 2009–10.

As part the AER's 2009 determination, it approved capex and opex allowances. From this, the AER determined an annual allowable revenue amount which, in effect, capped the rate of change to network charges the DNSPs could make within the current regulatory control period.

In November 2009 the Australian Competition Tribunal (Tribunal) reviewed the AER's 2009–14 distribution determinations for the NSW DNSPs. The Tribunal increased Ausgrid's controllable opex allowance. This led to increases of forecast revenue and allowable network charges.

The forecast revenue increases for Ausgrid, Endeavour Energy and Essential Energy were significant. As a result of the Tribunal's orders, Ausgrid's allowed revenue increased by $709 million,[3] Endeavour Energy's increased by $321 million and Essential Energy's increased by $411 million, for the 2009–14 regulatory control period.[4] The forecast revenue increases took effect in 2010–11 and apply until 2013–14.

Tables B to E compare the DNSPs' actual expenditure and revenue against the AER's approved forecasts or, for Ausgrid, the Tribunal's orders.

Further information on the DNSPs' capex, opex and revenue for 2009–10 is contained in chapter 3.

Table B ActewAGL 2009–10 financial performance ($m, 2009–10)

	Forecast	Actual	Difference	Difference (%)
Revenue	138.6	142.3	3.7	2.7
Capex	63.7	64.5	0.8	1.3
Opex	60.2	60.7	0.5	0.8

Table C Ausgrid 2009–10 financial performance ($m, 2009–10)

	Forecast	Actual	Difference	Difference (%)
Revenue	1213.3	1257.6	44.3	3.7
Capex	1143.0	1057.6	– 85.4	–7.5
Opex	476.5	510.0	33.5	7.0

3 This is the revenue increase for distribution services only.
4 AER, *State of the Energy Market 2010*, p. 7.

Table D Endeavour Energy 2009–10 financial performance ($m, 2009–10)

	Forecast	Actual	Difference	Difference (%)
Revenue	743.2	777.7	34.5	4.6
Capex	575.9	401.6	–174.3	–30.3
Opex	300.1	256.3	–43.8	–14.6

Table E Essential Energy 2009–10 financial performance ($m, 2009–10)

	Forecast	Actual	Difference	Difference (%)
Revenue	849.1	894.3	45.2	5.3
Capex	722.2	652.8	– 69.4	–9.6
Opex	399.2	367.1	–32.1	–8.0

Key observations in relation to the DNSPs' financial performance for 2009–10 are:

- ActewAGL earned the highest return on assets at 10 per cent, compared to its forecast of 9.8 per cent. ActewAGL's actual revenue, capex and opex were higher than forecast, with the difference in revenue being 2.7 per cent and the difference in capex and opex being around 1 per cent.

- Ausgrid earned a 7.9 per cent return on assets consistent with its forecast. Ausgrid's actual revenue was 3.7 per cent higher than forecast. Ausgrid spent less than its forecast capex by 7.5 per cent and spent more than its forecast opex by 7.0 per cent.

- Endeavour Energy earned a return on assets of 9.1 per cent which was higher than its forecast return on assets of 7.6 per cent. Endeavour Energy recovered higher revenue than forecast by 4.6 per cent. Of the DNSPs, Endeavour Energy recorded the largest difference between its forecast and actual capex and opex, underspending by approximately 30 per cent and 15 per cent, respectively.

- Essential Energy earned a return on assets of 7.4 per cent which was higher than its forecast of 6.2 per cent. Essential Energy recovered higher revenue than forecast and had the largest difference between its forecast and actual revenue of 5.3 per cent. Essential Energy spent less than its forecast capex and opex by 9.6 per cent and 8.0 per cent, respectively.

Overview of service performance

This report covers the DNSPs' 2009–10 service performance in relation to the supply reliability and customer service components of the STPIS.

In the AER's 2009–14 distribution determinations for ACT and NSW DNSPs, the AER did not apply a STPIS to the DNSPs which would financially reward or penalise them for their actual performance against a set performance target. Instead the AER decided it would collect and monitor service performance information with a view to setting firmer and more robust service targets in the next regulatory control period.

The service performance information reported for 2009–10 by the DNSPs has accuracy and reliability issues as set out in appendix A. The AER expects that these issues will be addressed in the current regulatory control period.

Reliability in 2009–10

Reliability refers to the continuity of electricity supply to customers and is measured by interruptions to supply. These are known as outages. Table E shows the frequency and duration of outages by reporting unplanned outages and unplanned minutes off supply per customer, for each DNSP.

Table F Average number of unplanned outages experienced per customer in 2009–10

DNSP	Unplanned outages	Unplanned minutes off supply
ActewAGL	0.6	26
Ausgrid	1.1	80
Endeavour Energy	1.0	79
Essential Energy	2.0	196

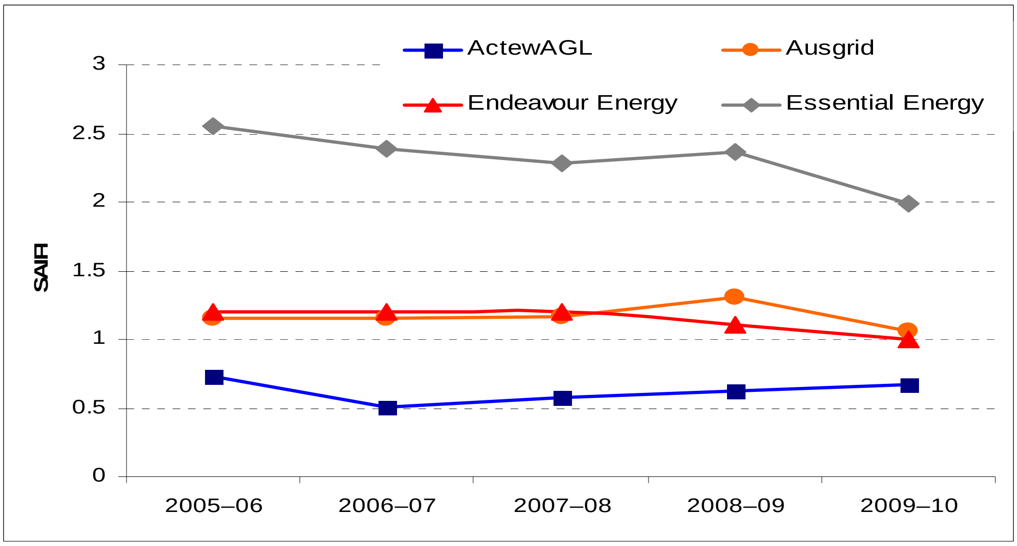
Note: Outage information includes excluded events. Figures are rounded.

Reliability 2005–06 to 2009–10

Figure A shows the average number of outages per customer on the DNSPs' networks from 2005–06 to 2009–10.[5] Figure A indicates that customers experienced fewer interruptions to electricity supply in 2009–10 than in 2005–06. While ActewAGL had the least number of unplanned outages in 2009–10 compared to the NSW DNSPs, its number of unplanned outages increased over the last three years to 2009–10.

5 Information has been sourced from jurisdictional scheme information for the period, excluding 2009–10 (which was collected by the AER).

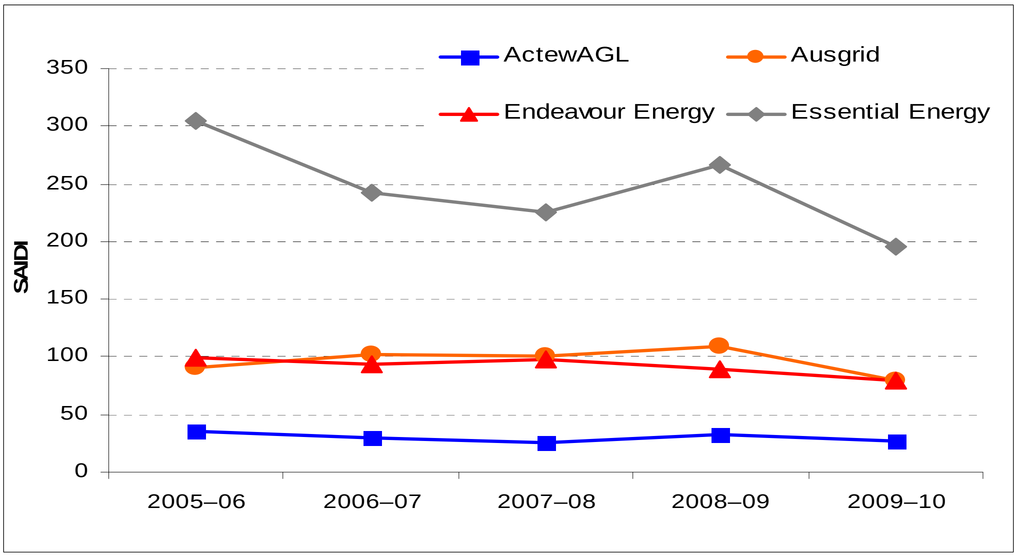
Figure A Average number of outages per customer for 2005–10



Source: The 2009–10 data is sourced from the DNSPs' RIN responses. The NSW DNSPs 2005–09 data is sourced from their 2009–10 '*Electricity Network Performance*' reports. ActewAGL's 2005–09 data is sourced from its *Annual and Sustainability Report 2009–10*.

Figure B shows the average minutes off supply[6] per customer on the DNSPs' networks from 2005–06 to 2009–10. Figure B shows that in 2009–10, the DNSPs' customers experienced shorter total interruptions to their electricity supply due to unplanned outages compared to the rest of the period.

Figure B Average minutes off supply per customer for 2005–10



Source: The 2009–10 data is sourced from the DNSPs' RIN responses. The NSW DNSPs 2005–09 data is sourced from their 2009–10 '*Electricity Network Performance*' reports. ActewAGL's 2005–09 data is sourced from its *Annual and Sustainability Report 2009–10*.

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6 This being the total number of minutes where a customer's electricity supply is interrupted which is then divided by the number of customers.

In general the DNSPs' service performance improved in 2009–10 due to the reduced number and duration of interruptions experienced by customers.

Customer service in 2009–10

The STPIS contains parameters relating to customer service. This report provides information about customer service in the context of telephone answering within 30 seconds in the ACT and NSW in 2009–10.

Essential Energy had the highest percentage of total telephone calls that were not answered within 30 seconds, followed by Ausgrid then ActewAGL. Endeavour Energy had the lowest percentage of total telephone calls not answered within 30 seconds.

Overview of demand management

The AER published a demand management incentive scheme (DMIS) in 2008 and it was applied to the 2009–14 distribution determinations for ACT and NSW DNSPs.

The aim of the DMIS is to provide incentives to conduct research into innovative techniques for managing demand. Accordingly, the purpose of the DMIS is to identify demand management projects as viable alternatives to network augmentation. The DMIS is divided into two parts; Part A – demand management innovation allowance (DMIA)[7] and Part B – foregone revenue.[8] Part A of the DMIS provides an ex-ante revenue allowance for DNSPs to conduct demand management activities. This ex-ante revenue allowance is built into DNSPs' annual revenue requirements. Any unspent allowance is deducted from DNSPs' revenue requirements in the next regulatory control period. Part B of the DMIS allows for the recovery of foregone revenue by DNSPs as a result of undertaking demand management projects approved by the AER under Part A.

In 2009–10 ActewAGL and Essential Energy claimed DMIA expenditure. The AER approved this DMIA expenditure as it meets the DMIA criteria. Information about ActewAGL and Essential Energy's demand management projects and the AER's assessment of their DMIA expenditure in 2009–10 is provided in appendix E. Neither Ausgrid nor Essential Energy claimed DMIA expenditure in 2009–10.

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7 AER's Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme, Part A – Demand management innovation allowance, November 2008.

8 AER's Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme, November 2008.

1 Introduction

This introduction outlines the Australian Energy Regulator's (AER's) performance reporting role, the AER's priorities and objectives for performance reporting, and the regulatory framework for performance reporting.

1.1 Performance reporting role

The AER is the economic regulator of network service providers (NSPs) in the National Electricity Market (NEM). NSPs own and/or operate the transmission and distribution networks used for transporting electricity from generators to consumers. The AER regulates NSPs under the National Electricity Law (NEL) and the National Electricity Rules (NER). In undertaking its economic regulatory functions the AER promotes the National Electricity Objective (NEO)[9] which is to:

> Promote efficient investment in, and efficient operation and use of electricity services for the long term interests of consumers of electricity with respect to electricity supply and the national electricity system.

As the economic regulator of NSPs in the NEM the AER's role includes annual performance reporting for regulated NSPs. Performance reporting is a vital part of the AER's functions and powers because it increases the transparency and accountability necessary to underpin efficiency based regulation. Reporting NSPs' performance also reduces the information gap between the regulated NSPs and other stakeholders.

The AER published its priorities and objectives for NSP performance reporting[10] and its strategy for networks information.[11] The AER's strategy for networks information aims to enhance transparency and make NSPs more publicly accountable for the way they spend their regulatory allowance. The AER has previously published annual performance reports for transmission NSPs and for Victorian distribution network service providers (DNSPs), the latter under the Essential Services Commission arrangements.[12] In future the AER intends to publish performance reports for all NEM DNSPs under the NEL.

Scope of this report

This report is the AER's first DNSP performance report prepared under the NEL. It contains financial and service performance information reported by the DNSPs to the AER in accordance with the AER's reporting requirements.

The financial and service performance information in this report relates to the 2009–10 regulatory year, which is the first year of the 2009–14 regulatory control period.

The financial information collected by the AER from the DNSPs for 2009–10 is based on their previous jurisdictional reporting requirements and is more limited than what

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9 Section 7 of the NEL.

10 AER, *Final Decision*: *Priorities and objectives of electricity network service provider performance reports*, April 2011.

11 AER, *Strategy for networks information*, June 2011.

12 http://www.aer.gov.au/content/index.phtml?itemId=731983

the AER is likely to seek from DNSPs in future.[13] The AER is aiming to develop benchmarks of DNSP financial performance to assist it in its future distribution determinations and to enable financial comparisons between DNSPs in future performance reports. The AER will undertake a detailed analysis of different DNSP costs as part of its benchmarking process which will be developed over time.[14] The AER's publication of DNSP performance reports, including this report, will enhance the AER's development of benchmarks by increasing transparency and enabling informed stakeholder participation in the AER's benchmarking process.

The service performance information collected by the AER from the DNSPs for 2009–10 is based on the AER's national service target performance incentive scheme (STPIS) which aims to incentivise DNSP service performance. The STPIS applies to the DNSPs as a paper trial without financial impact for the 2009–14 regulatory control period.[15] The AER has recently written to the DNSPs regarding the need for future accuracy and reliability improvements to the DNSPs' service performance information.[16] By continuing to develop its networks information and reporting framework over time, the AER is aiming to establish a reliable service performance data set and to include service performance target information in its future DNSP performance reports.

AER's continuing performance reporting role

From 2010–11, the AER will also begin performance reporting for the Queensland and South Australian DNSPs. Following this, the AER's reporting framework will apply to the Victorian DNSPs. From 2012–13 the AER's reporting framework will apply to the Tasmanian DNSP. The AER's aim is to develop a uniform performance reporting framework for all DNSPs.

The AER will continue to implement its networks information and reporting strategy and aims to progressively include more comprehensive financial and service performance information in future DNSP performance reports. The AER recognises that establishing its networks information strategy will take time.

The AER aims to collect a relatively stable and consistent set of data from DNSPs that will meet its analytical and reporting needs by June 2013. NSPs currently provide information to the AER that varies in content and format, and some NSPs may initially have difficulties in meeting all of the AER's new information requirements. However, the AER will work with the NSPs so they can implement changes to their information reporting systems to meet the AER's information requirements, within a reasonable timeframe.

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13 During the previous regulatory control period ActewAGL was regulated by ICRC and Ausgrid, Endeavour Energy and Essential Energy were regulated by IPART.

14 Potential reasons for differences in DNSP costs are provided in appendix A of this report.

15 AER, *Final decision: New South Wales distribution determination 2009–10 to 2013–14*, April 2009; AER, *Final decision: Australian Capital Territory distribution determination 2009–10 to 2013–14*, April 2009; AER, *Final decision: Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations*, February 2008; Clause 6.6.2(h) of the transitional chapter 6 of the NER.

16 A summary of the accuracy and reliability issues regarding the ACT and NSW DNSPs' 2009–10 service performance information is provided in appendix A of this report.

1.2 Priorities and objectives of performance reporting

In April 2011 the AER published its priorities and objectives for NSP performance reporting in accordance with clause 8.7.4 of the NER.[17] The AER's priorities and objectives for NSP performance reporting reflect the NEO.

In brief, the AER's objectives for NSP performance reporting are educating stakeholders, providing transparency, maintaining accountability and incentivising increased performance. In order to achieve these objectives, the AER's priorities for NSP performance reporting are to:

- report the NSPs' compliance with approved cost allocation methods, and elements of the regulatory determination, including service standards and incentive schemes
- report the NSPs' forecast and actual outputs, including measures of network utilisation and asset age, to identify areas of NSP performance that may be reviewed by the AER
- report forecast and actual capital expenditure (capex) and operating expenditure (opex), and identify reasons for differences between forecast and actual expenditures
- report benchmark expenditure information to allow comparison of NSP performance over time and between NSPs and across jurisdictions
- report and compare the NSPs' network operations, including service standard levels and demand management information
- report comprehensive, accurate and reliable information, enabling stakeholders to undertake analysis of performance and have confidence in the results of that analysis. Provide information over time to enable trends to be identified and comparisons of changes in performance, outputs and expenditures to be made between NSPs
- report the NSPs' profitability, comparing businesses within and across jurisdictions and regulatory control periods
- report information that can be utilised for future distribution determinations, including information on cost drivers, expenditure trends and service levels
- report on variations in network performance.

1.3 Regulatory framework for performance reporting

The provisions of the NEL and NER that are relevant to the AER's performance reporting are as follows:

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17 AER, *Final Decision*: *Priorities and objectives of electricity network service provider performance reports*, April 2011.

- section 7 of the NEL provides that the NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to electricity supply and the national electricity system

- section 15(1)(ea) of the NEL confers functions and powers on the AER to prepare and publish reports on the financial and operational performance of electricity NSPs

- section 28F(3)(d) of the NEL provides that a regulatory information notice (RIN) must not be served for the sole purpose of collecting information for performance reporting

- section 28V of the NEL provides for the AER to report on the financial or operational performance, network profitability and other performance matters as considered appropriate

- clause 8.7.4(a) of the NER provides that prior to the AER publishing NSP performance reports it must determine appropriate priorities and objectives for the reports

- clause 8.7.4(b) of the NER provides that in preparing a NSP performance report the AER must consult with the relevant NSPs and jurisdictional authorities regarding safety and technical obligations

- clause 8.7.4(c) of the NER requires the AER to give an NSP to which the report relates an opportunity to comment on a draft report prior to the publication of the final report.

1.4 Structure of this report

This report is structured as follows:

- chapter 1 details the AER’s performance reporting role and the regulatory framework

- chapter 2 details electricity distribution in the NEM and general network information for the DNSPs in 2009–10

- chapter 3 details the DNSPs’ financial performance in 2009–10 with respect to standard control services

- chapter 4 details the DNSPs’ financial performance in 2009–10 with respect to alternative control services

- chapter 5 outlines the AER’s national STPIS and details the DNSPs’ service performance in 2009–10

- appendix A details the sources of information used in this report and the limitations of service performance data

- appendix B provides historical and 2009–10 general network information of the DNSPs
- appendix C provides financial performance information on the DNSPs’ capex and opex drivers, revenue, capex, opex and capital contributions in 2009–10. Appendix C also provides historical financial performance information of the DNSPs
- appendix D provides historical service performance information, customer service information for 2009–10
- appendix E outlines the AER’s DMIS and provides information on the AER’s assessment of ActewAGL and Essential Energy’s 2009–10 demand management innovation allowance (DMIA) expenditures
- appendix F contains the DNSPs’ 2009–10 DMIA reports.

2. Electricity distribution networks

This chapter provides information about electricity distribution in the NEM and general information regarding the DNSPs' networks in 2009–10.

2.1 Electricity distribution in the NEM

The NEM is a wholesale market through which generators and retailers trade electricity in eastern and southern Australia. The NEM spans six jurisdictions including Queensland (Qld), NSW, ACT, Victoria (Vic), South Australia and Tasmania that are physically linked by an interconnected transmission network.[18]

The NEM has around 200 large generators, five state based transmission networks (linked by cross–border interconnectors) and 13 major distribution networks that supply electricity to customers. The NEM meets the demand of almost nine million residential, commercial and industrial energy users and is the largest interconnected power system in the world in geographic span, covering a distance of 4500 km.[19]

Distribution networks transport electricity from transmission networks to residential and business customers. A distribution network consists of the poles and wires that carry electricity, as well as substations, transformers, switching equipment, and monitoring and signalling equipment.

While electricity is transported along transmission networks at high voltages to minimise energy losses, it must be stepped down to lower voltages in a distribution network for safe use by customers. Most customers in Australia require delivery at around 230–240 volts. Distribution networks cross urban and regional areas to provide electricity to customers. This requires substantial investment in infrastructure. The total length of distribution infrastructure is around 750 000 km in the NEM.[20]

Electricity distributors provide the infrastructure to transport electricity to household and business customers, but they do not sell electricity. Electricity retailers bundle electricity generation with transmission and distribution services, and sell them as a package. Qld, NSW, and Victoria have multiple DNSPs. Each DNSP is a monopoly provider in a designated area.

In ACT, South Australia and Tasmania there is one DNSP in each jurisdiction. There are also small regional networks with separate ownership in some jurisdictions. Figure 2.1 shows the DNSPs in the NEM.

[18] AER, *State of the Energy Market 2009* (2009), pp. 72–73.
[19] AER, *State of the Energy Market 2010* (2010), p. 19.
[20] AER, *State of the Energy Market 2009* (2009), p. 155.

Figure 2.1 Distribution networks in the NEM

Source: AER, *State of the Energy Market 2011*, p. 54.

2.2 ACT and NSW DNSPs

In the ACT the relevant DNSP is ActewAGL. Ausgrid, Endeavour Energy and Essential Energy are the DNSPs operating in NSW. All four DNSPs are monopolies in their designated service areas.

ActewAGL

ActewAGL Distribution provides electricity distribution services in the ACT. It is a partnership between ACTEW Distribution Ltd and Jemena Networks (ACT) Pty Ltd.

Ausgrid

Ausgrid is a NSW state owned corporation that provides electricity distribution services in Sydney (including the Central Business District), Central Coast, and the Hunter region.

Endeavour Energy

Endeavour Energy is a NSW state owned energy corporation that provides electricity distribution services in Sydney's Greater West, Illawarra, the Blue Mountains and the Southern Highlands.

Essential Energy

Essential Energy is a NSW state owned corporation which provides electricity distribution services to the remainder of NSW, parts of southern Qld and northern Vic.

Network information

This section provides forecast and actual information relating to maximum demand, energy delivered and customer numbers for the DNSPs in 2009–10. It also includes information concerning line length and the number of full time employees employed by the DNSPs for 2009–10. The information contained in tables 2.1 to 2.4 are for the network as a whole and therefore include both standard and alternative control services provided by the DNSPs.

ActewAGL's forecast maximum demand and forecast customer numbers for 2009–10 are not contained in this report. This information was not published in the AER's 2009–14 distribution determination for the ACT, as ActewAGL did not include forecast customer numbers in its regulatory proposal.[21]

Appendix B provides further information about the maximum demand, energy delivered and customer numbers by the DNSPs from 2005–06 to 2009–10.

Maximum demand

Table 2.1 shows that actual maximum demand for all of the NSW DNSPs was lower than forecasts.

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[21] ActewAGL's RIN which accompanied its regulatory proposal included historical customer numbers for the previous regulatory control period only. The AER has requested ActewAGL provide forecast customer numbers in its annual reporting regulatory information notice (RIN).

Table 2.1 Forecast and actual maximum demand for 2009–10

DNSP	Forecast maximum demand (MW)	Actual maximum demand (MW)	Difference	Difference (%)
ActewAGL	689 (MVA)	604	–	–
Ausgrid	6 022	5 609	–413	–6.9
Endeavour Energy	4 179	3 722	–457	–10.9
Essential Energy	2 391	2 239	–152	–6.4

Source: Actual figures are sourced from the DNSPs' 2009–10 regulatory accounts. Forecast figures are sourced from the AER's 2009 determinations. ActewAGL's forecast maximum demand in the AER's 2009 determination was provided on an MVA basis rather than a MW basis.

Energy Delivered

Table 2.2 shows that there was little difference between actual and forecast energy delivered in the ACT and NSW for 2009–10.

Table 2.2 Forecast and actual energy delivered for 2009–10

DNSP	Forecast energy delivered (GWh)	Actual energy delivered (GWh)	Difference	Difference (%)
ActewAGL	2 933	2 908	–25	–0.9
Ausgrid	27 948	27 527	–421	–1.5
Endeavour Energy	17 373	17 410[22]	37	0.2
Essential Energy	12 092	12 103	11	0.1

Source: Actual figures are sourced from the DNSPs' 2009–10 regulatory accounts. Forecast figures are sourced from the AER's 2009 determinations.

Customer Numbers

Table 2.3 shows that Ausgrid's actual customer numbers was higher than forecast by 3 per cent. Endeavour Energy's and Essential Energy's actual customer numbers were close to their 2009–10 forecast with the difference being within less than ± 1 per cent of actual customer numbers.

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[22] This figure includes inter-distributors transfers.

Table 2.3 Forecast and actual customer numbers for 2009–10

DNSP	Forecast number of customers	Actual number of customers	Difference	Difference (%)
ActewAGL	–	164 900	–	–
Ausgrid	1 559 297	1 605 635	46 338	3.0
Endeavour Energy	860 392	866 767	6 375	0.7
Essential Energy	804 157	798 356	–5 801	–0.7

Source: Actual figures are sourced from the DNSPs' 2009–10 regulatory accounts. Forecast figures are sourced from the AER's 2009 NSW DNSPs' determinations. ActewAGL did not provide its customer numbers in its 2009–10 regulatory proposal.

Number of full time equivalent employees and line length

Table 2.4 shows the DNSPs' full time employees and line lengths for 2009–10.

Table 2.4 Network statistics for 2009–10

DNSP	Number of full time equivalent employees	Line length (km)
ActewAGL	–	4 858
Ausgrid	5 780[23]	44 839
Endeavour Energy	2 202[24]	33 817
Essential Energy	4 474	178 492

Source: ActewAGL's line length number is sourced from its *2009–10 Annual and Sustainability Report*. Line length and full time employee information for the NSW DNSPs is sourced from their 2009–10 electricity distribution network performance reports.

23 This number is the total number of employees working in both Ausgrid's distribution and transmission business.

24 Endeavour Energy's Electricity Network Performance Report (2009–10) notes employee numbers includes all employees within the Network Division, Corporate Services – Technical Training, Health and Safety – Compliance and Audit, Operational and Safety Management System.

3 Financial performance (standard control services)

This chapter outlines the financial performance of the DNSPs in 2009–10 in relation to standard control services.[25] The measures of financial performance used in this report include revenue, capex, opex and profitability (return on assets).

The DNSPs reported their actual 2009–10 revenue, opex and capex for standard control services to the AER in their regulatory accounts. In this chapter, the actual figures are compared with the corresponding forecasts included in the AER's 2009–14 distribution determinations for the ACT and NSW DNSPs. In the case of Ausgrid, the actual 2009–10 opex figures are compared with the forecast opex allowance resulting from the Australian Competition Tribunal's (Tribunal's) orders.

This chapter also provides high level information about the reasons for the difference between forecast and actual revenue, capex and opex in 2009–10. The AER will request more detailed information from the DNSPs in future.

Appendix A contains information about the sources of the financial information in this report. Appendix C contains additional financial information for the DNSPs, including information from the previous regulatory control period.

3.1 Revenue

This section provides high level information about the role of revenue in regulating electricity DNSPs and the DNSPs' revenue during 2009–10 for standard control services.

Revenue in electricity distribution

The AER's 2009–14 distribution determinations for the ACT and NSW DNSPs applied different revenue or price control mechanisms to the DNSPs for the 2009–14 regulatory control period as follows:

- an average revenue cap (ARC) which sets a ceiling on revenue yields that may be recovered during a regulatory control period for ActewAGL
- a weighted average price cap (WAPC) which places a ceiling on the prices of distribution services during a regulatory control period for Ausgrid, Endeavour Energy and Essential Energy.

In making a distribution determination, the AER forecasts the revenue required by a DNSP to cover at least its efficient costs and provide it with a commercial rate of return. The AER uses a building block model to determine a DNSP's forecast revenue. The components of the building block model are: opex, depreciation, a

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25 ActewAGL's regulated distribution services were classified as standard control services. However, this excludes services relating to the provision and service of meters for customers consuming below 160 MWh per annum. These were classified as alternative control services. The NSW DNSP's regulated distribution services were classified as standard control services. However, this excludes services relating to the construction and maintenance of public lighting, which were classified as alternative control services.

return on capital, and taxation liabilities. In setting these elements, the AER has regard to various factors including demand projections, price stability, and the potential for efficiency gains in opex, capex and service standards.

Based on the forecast revenues, X factors (real revenue or price changes) are determined by the AER. These are used under the consumer price index (CPI)-X framework to update revenues or prices on an annual basis. A number of factors may result in differences between a DNSP's actual revenue and the revenue forecast by the AER, including:

- Differences in forecast and actual CPI— the ARC and WAPC are determined using a forecast inflation rate for the duration of the regulatory control period. The ARC and WAPC are adjusted annually for actual CPI to preserve the real value of the revenue stream.

- Differences between forecast and actual quantities of electricity distributed—under a price cap, the X factors in the AER's 2009 determinations are based on forecast quantities of demand. If the forecast quantities differ from actual quantities there will be differences between forecast and actual revenues.

- Pass throughs—in certain circumstances DNSPs are able to pass through additional costs that occur during the regulatory control period that were not contemplated at the time of the AER's 2009 determinations. Approved pass through amounts are added to the allowed revenues during a regulatory control period.

- D–factors (NSW only)—the D–factor scheme allows the NSW DNSPs to recover costs and foregone revenues associated with approved demand management projects. D–factors are not included in the forecast revenue but are applied to forecast revenues at the time of the annual pricing approval process.

2009–10 revenue

Table 3.1 shows the DNSPs' actual revenue during 2009–10 compared to the forecasts that were provided in the AER's 2009 determination.

Table 3.1 Comparison of forecast and actual revenues for 2009–10 ($m, 2009–10)

DNSP	Forecast revenue	Actual revenue	Difference	Difference (%)
ActewAGL	138.6	142.3	3.7	2.7
Ausgrid	1213.3	1257.6	44.3	3.7
Endeavour Energy	743.2	777.7	34.5	4.6
Essential Energy	849.1	894.3	45.2	5.3

Note: Figures are rounded to one decimal place. Actual figures are sourced from the DNSPs' 2009–10 regulatory accounts. Forecast figures are sourced from AER's 2009 determinations and adjusted by actual CPI to reflect mid 2009–10 regulatory year dollar terms.

Table 3.1 shows that in 2009–10:

- ActewAGL's revenue varied from its forecast allowance by $3.7 million, which is 2.7 per cent higher than forecast. ActewAGL considered this was largely attributable to CPI and accounting adjustments.[26]
- Ausgrid's revenue varied from its forecast allowance by $44.3 million, which is 3.7 per cent higher than forecast. Ausgrid considered this was attributable to the difference between forecast and actual volumes at the tariff component in 2009–10 used in calculating the X–factor. Ausgrid further considered this could arise from temperature variations, economic developments, population growth and customer price responsiveness.[27]
- Endeavour Energy's revenue varied from its forecast allowance by $34.5 million, which is 4.6 per cent higher than forecast. Endeavour attributed the difference to modest growth in energy delivered and customer numbers above the regulatory forecasts, movement between tariff categories with different prices, and the difference between actual and forecast CPI.[28]
- Essential Energy's revenue varied from its forecast allowance by $45.2 million, which is 5.3 per cent higher than forecast. Essential Energy considered this was attributable to the CPI adjustment.[29]

3.2 Capex

This section provides high level information about the AER's approach to approving capex forecasts and the DNSPs' capex during 2009–10 for standard control services.

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[26] ActewAGL, email to AER, 4 October 2011.
[27] Ausgrid, email to AER, 4 October 2011.
[28] Endeavour Energy, email to AER, 8 November 2011.
[29] Essential Energy, email to AER, 7 October 2011.

Capex in electricity distribution

DNSPs undertake capex by investing in infrastructure for various reasons. These reasons include:

- augmenting (expanding) the network to meet rising demand
- replacing ageing assets
- maintaining or improving network performance
- meeting regulatory requirements, such as reliability standards.

Capex is added to the regulatory asset base, which is used to derive the depreciation and return on investment components of the building block model. As part of its regulatory proposal a DNSP is required to propose a capex forecast that addresses the capex objectives as set out in the NER including meeting the expected demand, complying with applicable regulations, and maintaining the reliability, quality, security of supply and the safety of the distribution system.

The AER's 2009–14 distribution determinations for the ACT and NSW DNSPs, considered the forecast capex allowance necessary for the DNSPs to operate efficiently based on their network requirements. Differences in operating environments result in different capex requirements for each DNSP. These differences may relate to the age and condition of the network, load characteristics, the costs of meeting the demand for new connections and obligations, requirements in relation to licensing, reliability and safety.

2009–10 capex

Table 3.2 shows the DNSPs' actual capex during 2009–10 compared with the forecast capex allowances from the AER's 2009 determination. Appendix C provides capex information by driver for 2009–10.

Table 3.2 Comparison of forecast and actual capex for 2009–10 ($m, 2009–10)

DNSP	Forecast capex	Actual capex	Difference	Difference (%)
ActewAGL	63.7	64.5	0.8	1.3
Ausgrid	1143.0	1057.6	– 85.4	–7.5
Endeavour Energy	575.9	401.6	–174.3	–30.3
Essential Energy	722.2	652.8	– 69.4	–9.6

Note: Figures are rounded to one decimal place. Actual figures are sourced from the DNSPs' 2009–10 regulatory accounts. Forecast figures are sourced from AER's 2009 determinations and adjusted by actual CPI to reflect mid 2009–10 regulatory year dollar terms.

Table 3.2 shows that in 2009–10:

- ActewAGL's actual capex was more than its forecast allowance by 1.3 per cent
- Ausgrid's actual capex was less than its forecast allowance by 7.5 per cent
- Endeavour Energy's actual capex was less than its forecast allowance by 30.3 per cent
- Essential Energy's actual capex was less than its forecast allowance by 9.6 per cent.

ActewAGL was the only DNSP to exceed its forecast capex allowance.

The AER requested the NSW DNSPs to provide the main reasons for differences between forecast and actual capex in 2009–10. In reviewing the DNSPs' responses the AER notes a common explanation provided by the NSW DNSPs' for the capex underspend was due to delays in implementing projects and programs. Further:

- Ausgrid's forecast expenditure on Sydney property acquisition, growth expenditure, environment, safety and statutory obligation expenditure, and non-system asset expenditure was lower than the AER's 2009 determination allowance. Ausgrid considered this delay in expenditure was offset by accelerations in asset renewal and replacement expenditure, expenditure on the low voltage distribution network and reliability and quality of service enhancement expenditure.[30]
- Endeavour Energy considered its forecast non-system capex was below AER approved levels due to the leasing of passenger and light commercial vehicles which aligned with capex reduction requirements (as per the November 2008 NSW State Mini Budget) as these were not incorporated into Endeavour Energy's forecasts.[31]
- Essential Energy considered expenditure to meet load growth was higher than forecast due to the global financial crisis impacting Essential Energy less than originally anticipated. Essential Energy advised it rescheduled planned capital work programs to allow for lower expenditure in 2009–10.[32]

3.3 Opex

This section provides high level information about the AER's approach to approving opex forecasts and the DNSPs' opex during 2009–10 for standard control services.

Opex in electricity distribution

DNSPs incur opex in maintaining the functionality of their distribution networks. Opex typically includes wages and salaries, asset maintenance costs and other costs related to the provision of distribution services.

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30 Ausgrid, email to AER, 4 October 2011.
31 Endeavour Energy, email to AER, 28 October 2011.
32 Essential Energy, email to AER, 7 October 2011.

Opex is one component of the building block model that the AER uses to make a determination on the revenue that a DNSP needs to cover its efficient costs and provide a commercial rate of return to the business. As part of its regulatory proposal, a DNSP proposes an opex forecast to achieve the opex objectives as set out in the NER including: meeting the expected demand, complying with applicable regulations, and maintaining the reliability, quality, security of supply and safety of the distribution system.

In the AER's 2009–14 distribution determinations for the ACT and NSW DNSPs, it forecast an opex allowance for the DNSPs to operate efficiently based on their network requirements for the current regulatory control period. Differences in operating environments may result in different opex requirements for each DNSP. These differences may include customer and load densities, the scale condition and age of the networks, geographic factors, and reliability requirements.

Efficiency Benefit Sharing Scheme

The regulatory framework is designed to give the DNSPs an incentive to increase their forecast return by improving operating efficiency. The AER applies an efficiency benefit sharing scheme (EBSS) to incentivise DNSPs to achieve efficient opex in managing their networks. This is done by allowing DNSPs (to retain for a given period of time) any opex efficiency gains made against a benchmark opex target.

In June 2008, as part of the national framework for distribution regulation, the AER published an EBSS that applies to all DNSPs.[33] The AER has commenced collecting EBSS information from the DNSPs. The EBSS will not have a direct financial impact on the DNSPs until the next regulatory control period.[34] Appendix C contains the EBSS information reported to the AER by the DNSPs for 2009–10.

2009–10 opex

Table 3.3 shows the DNSPs' actual opex during 2009–10 compared to the forecast opex allowances that were either provided in the AER's 2009 determination, or in the case of Ausgrid, resulted from the Tribunal's orders. Appendix C provides opex information by drivers for 2009–10.

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[33] AER, *Final decision: Electricity distribution network service providers: efficiency benefit sharing scheme*, June 2008.

[34] AER, *Final Decision: Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, February 2008.

Table 3.3 Comparison of forecast and actual opex for 2009–10 ($m, 2009–10)

DNSP	Forecast opex	Actual opex	Difference	Difference (%)
ActewAGL	60.2	60.7	0.5	0.8
Ausgrid	476.5	510.0	33.5	7.0
Endeavour Energy	300.1	256.3	–43.8	–14.6
Essential Energy	399.2	367.1	–32.1	–8.0

Note: Figures are rounded to one decimal place. Actual figures are sourced from the DNSPs' 2009–10 regulatory accounts. Forecast figures are sourced from the AER's 2009 determinations or for Ausgrid, Tribunal orders and adjusted by actual CPI to reflect mid 2009–10 regulatory year dollar terms.

Table 3.3 shows that:

- ActewAGL's actual expenditure aligned closely with its forecast allowance, with a difference of 0.8 per cent
- Ausgrid spent more than its forecast allowance by 7.0 per cent
- Endeavour Energy spent less than its forecast allowance by 14.6 per cent
- Essential Energy spent less than its forecast allowance by 8.0 per cent.

Analysis provided by Endeavour Energy and Essential Energy explains the main reasons for differences between forecast and actual opex. Specifically:

- Endeavour Energy noted the primary driver between approved forecast data and opex incurred was direct productivity based initiatives[35]
- Essential Energy noted delayed commencement of work programs was due to securing additional delivery capacity later in 2009–10 than forecast. Essential Energy stated that its work program will be completed during the current regulatory control period.[36]

Ausgrid did not supply the AER with information to substantiate the difference between forecast and actual opex spent.

[35] Endeavour Energy, email to AER, 28 October 2011.
[36] Essential Energy, email to AER, 7 October 2011.

3.4 Profitability (return on assets)

This section provides information about the AER's method used to calculate return on assets.[37] It also sets out the AER's forecast and actual return on assets for the DNSPs in relation to standard control services in 2009–10.

Method for calculating return on assets

The return on assets is a measure of overall financial performance and profitability. The ratio is expressed as operating profits (net profit before interest and taxation) as a percentage of the average regulatory asset base (RAB). A variety of factors can affect the return on assets, including differences in the demand and cost environments faced by each business. An increase in revenue or a decrease in opex increases the return on assets. DNSPs do not earn a return on assets that are funded through capital contributions, as these contributions are not included in the RAB.

The following formula has been used to calculate the return on assets:

$$\text{Return on Assets (\%)} = \frac{\text{Revenue} - \text{Opex} - \text{Regulatory depreciation}}{\text{Average RAB}}$$

Where:

Average RAB = the average of the opening and closing 2009–10 RAB.[38]

Return on assets, forecast and actual

Table 3.4 provides the DNSPs' forecast and actual return on assets for 2009–10 for their distribution services that were classified as standard control services.

Table 3.4 Forecast and actual return on assets for 2009–10

DNSP	Forecast return on assets (%) [39]	Actual return on assets (%)[40]	Difference
ActewAGL	9.8	10.0	0.2
Ausgrid	7.9	7.9	0
Endeavour Energy	7.6	9.1	1.5
Essential Energy	6.2	7.4	1.2

Note: Figures are rounded to one decimal place.

37 The return on assets formula used by the AER is not a measurement of WACC.

38 The AER has used figures from the AER's published roll forward model (RFM) and post tax revenue model (PTRM) for each DNSP for the opening RAB for 2009–10. The AER has used actual 2009–10 data as reported in the ACT and NSW DNSPs' regulatory accounts to calculate the closing RAB for 2009–10.

39 The AER has calculated the forecast return on assets by using closing 2009–10 RAB figures and forecast revenue, opex and regulatory depreciation.

40 The AER has used pre–tax and interest cost figures in calculating the actual return on assets.

Table 3.4 shows that in 2009–10:

- ActewAGL earned the highest return on assets at 10 per cent, which closely aligned with its forecast return on assets.
- Ausgrid's return on assets was 7.9 per cent which was equal to its forecast.
- Endeavour Energy earned the second highest return on assets at 9.1 per cent which was higher than its forecast return on assets. The better than forecast profitability was due to higher revenue and lower opex.
- Essential Energy earned the lowest return on assets at 7.4 per cent which was higher than its forecast return on assets. As with Endeavour Energy, the better than forecast profitability was due to higher revenue and lower opex.

4 Financial performance – alternative control services

This chapter provides information about the DNSPs' financial performance with respect to the provision of alternative control services in 2009–10.

ActewAGL

Under the transitional chapter 6 rules, a distribution service provided by ActewAGL that was previously classified as an 'excluded service' by the Independent Competition and Regulatory Commission (ICRC) was deemed to be classified as an alternative control service. Therefore, the AER classified the provision and service of meters for customers consuming below 160 MWh per annum as an alternative control service. [41]

Consistent with the approach applied by the ICRC, the form of control mechanism applied to ActewAGL's alternative control services was a revenue allowance based on a building block analysis, with maximum allowed revenues escalated each year by CPI.

Table 4.1 ActewAGL revenue, capex and opex for metering services ($m, 2009–10)

	Actual	Forecast	Difference ($m)	Difference (%)
Revenue	7.4	7.5	–0.1	–1.33
Opex	–	2.2	–	–
Capex	3.6	6.3	–2.7	–42.86

Note: Figures are rounded to one decimal place. ActewAGL's alternative control service opex was not reported as the AER did not receive this information in ActewAGL's 2009–10 regulatory accounts.

In accordance with clause 6.12.1(13) of the transitional chapter 6 rules ActewAGL is required to demonstrate compliance with the control mechanism for alternative control services by submitting a schedule of metering charges to the AER as soon as practicable after prices for each regulatory year are determined. Compliance is shown by calculating the revenue that would have been earned from the proposed prices if they had been applied to the quantities sold in the previous calendar year.

NSW DNSPs

Under the transitional chapter 6 rules the provision and maintenance of public lighting by the NSW DNSPs was classified as alternative control services for the 2009–14 regulatory control period.

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[41] AER, *Final decision: New South Wales distribution determination 2009–10 to 2013–14,* April 2009, Chapter 18, p.146.

In accordance with clause 6.12.1(12) of the transitional chapter 6 rules the AER applied the following control mechanisms to NSW DNSPs' public lighting services:

- a schedule of fixed charges in the first year of the regulatory control period for assets constructed before 1 July 2009 developed using a building block approach

- a schedule of fixed prices in the first year of the regulatory control period for assets constructed after 30 June 2009 developed using an annuity capital charge approach

- a price path, based on CPI, for the remaining years of the regulatory control period.

In accordance with clause 6.12.1(13) of the transitional chapter 6 rules the NSW DNSPs' compliance with the alternative control services mechanism is to be demonstrated as follows:

- In relation to assets constructed before 1 July 2009, by providing the AER with the charges it proposes to levy on each of its public lighting customers over the next regulatory year as part of its annual pricing proposal, including an explanation of any adjustments.

- In relation to assets constructed after 30 June 2009, by publishing the indexed tariff for the relevant regulatory year (with 2009–10 as the base year tariff) at the same time its general network tariffs are published.

In its draft decision, the AER required the NSW DNSPs to submit their proposed schedules for fixed prices and price path using the approach set out in section 17.6.11 of the draft decision. Each of the NSW DNSPs has complied with this requirement.

In 2009–10 the public lighting revenue earned by Ausgrid, Endeavour Energy and Essential Energy was $29.2 million, $15.2 million and $8 million, respectively.[42]

[42] These figures were sourced from the NSW DNSPs' regulatory accounts.

5 Service performance

This chapter outlines the STPIS and provides service performance information about the DNSPs.

5.1 Overview of the AER's national STPIS

With the move to national distribution regulation, the AER published a national STPIS in 2009 to encourage DNSPs to maintain and improve service performance for the long-term benefit of end users. The regulatory regime as a whole encourages DNSPs to improve their efficiency. The STPIS is designed to ensure that these efficiency improvements are not made at the expense of service performance for customers.

The STPIS involves setting targets for service performance and provides financial bonuses (or penalties) of up to 5 per cent of revenue to network businesses that meet (or fail to meet) performance targets. The results are standardised for each network to derive the 's–factor'[43] that reflects deviations from target performance levels. The STPIS comprises four components: the reliability of supply, customer service, guaranteed service level (GSL), and the quality of supply.[44]

The STPIS allows for certain adverse events that are considered to be beyond the DNSP's control to be excluded from impacting the calculation of the bonuses (or penalties). The STPIS sets out various exclusions including: load shedding due to a generation shortfall; load interruptions caused by a failure of the shared transmission network or transmission connection assets; and where daily unplanned system average interruption duration index exceeds the major event day boundary. Information about events that would have been classified as exclusions during 2009–10 is provided in section 3.3 of the STPIS.

Implementation of the STPIS

The STPIS will apply, over time, to all DNSPs in the NEM. The AER determined that a STPIS with financial impact would not be introduced for the DNSPs for the 2009–14 regulatory control period.[45]

However, the AER expects the DNSPs to implement measures to achieve full compliance with the STPIS as soon as practical.[46] The application of the STPIS to the DNSPs in the next regulatory control period will be subject to a consultation process prior to the AER's 2014–19 distribution determinations for the ACT and NSW

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43 The service standard factor (s-factor) is defined in the STPIS as percentage revenue increment (or decrement) that applies in each regulatory year.

44 The STPIS does not contain any parameters relating to the quality of supply component.

45 AER, *Final decision: New South Wales distribution determination 2009–10 to 2013–14,* April 2009; AER, *Final decision: Australian Capital Territory distribution determination 2009–10 to 2013–14,* April 2009; AER, *Final decision: Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations,* February 2008; Clause 6.6.2(h) of the transitional chapter 6 of the NER.

46 AER, *Final decision: New South Wales distribution determination 2009–10 to 2013–14*, April 2009, p. 244; AER, *Final decision: Australian Capital Territory distribution determination 2009–10 to 2013–14*, April 2009, p. 112.

DNSPs. In making its determination the AER will engage with the DNSPs and stakeholders to determine appropriate targets under the STPIS.

Service performance reporting

The AER has commenced collecting information from the DNSPs in relation to the STPIS.[47] Sections 5.2 and 5.3 of this chapter contain information on reliability of supply and customer service components of the STPIS for 2009–10. This information is the first service performance information provided to the AER by the DNSPs in accordance with the AER's information and reporting requirements.

The reliability of supply information provided by the DNSPs has accuracy and reliability issues as detailed in appendix A. The AER notes the extent to which the DNSPs were able to provide accurate and reliable data was dependent on the systems and processes that were in place during 2009–10, prior to the AER issuing its data request.

The AER is refining its STPIS reporting requirements to enable it to continue implementing its network information and reporting strategy. It expects a reliable data series for the implementation of the STPIS for the DNSPs in the next regulatory control period. In June 2011, the AER requested advice from the DNSPs regarding their intention to address key STPIS limitations within the current regulatory control period. The AER sought this to prevent the delay or complication of implementing the STPIS by July 2014. The AER anticipates that its future DNSP performance reports will deliver reliable and more comprehensive service performance information as the STPIS is implemented and service performance targets are developed.

This report does not cover the GSL component of the STPIS as the AER did not collect relevant information from the DNSPs for 2009–10. All jurisdictions continue to regulate the service performance of DNSPs through GSLs. If performance does not meet GSLs, customers are paid compensation directly by the DNSPs. Jurisdictional GSLs relate to network reliability, technical quality of service and customer service and are designed to ensure DNSPs do not have an incentive to neglect regions or individual customers within their network. Although the STPIS has a GSL component, in 2008 the AER decided not to apply the GSL component of the STPIS to the DNSPs because they were already subject to jurisdictional obligations.[48] Information about the NSW DNSPs' service performance regarding GSL in 2009–10 has been published by the Independent Pricing and Regulatory Tribunal (IPART).[49]

5.2 Reliability

This section of the report provides information about the reliability component of the STPIS and about the DNSPs' reliability in 2009–10.

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[47] In accordance with clause 6.6.2(h) of the transitional chapter 6 of the NER.

[48] AER, *Final Decision: Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations,* February 2008.

[49] IPART, *Distribution businesses' performance against customer service indicators in NSW,* May 2011.

Reliability and the STPIS

Reliability refers to the continuity of electricity supply to customers and is measured by interruptions to supply, known as outages, and the duration of those outages. Some outages are inevitable and customers cannot be guaranteed continuous supply. Outages may be planned or unplanned:

- Planned outages occur when a distributor needs to disconnect supply to undertake maintenance or construction works. Such interruptions can be timed to reduce the impact on customers.

- Unplanned outages occur when equipment failure causes the supply of electricity to be unexpectedly disconnected. They may result from operational error, asset overload or deterioration, or external causes such as damage caused by trees, birds, possums, vehicle impacts or vandalism. Networks can also be vulnerable to extreme weather, such as bushfires or storms.

Reliability parameters in the STPIS

The STPIS contains the following reliability of supply parameters:

- Unplanned System Average Interruption Duration Index (unplanned SAIDI). SAIDI measures average minutes off supply per customer. Unplanned SAIDI is the sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers. Unplanned SAIDI excludes momentary interruptions (one minute or less).

- Unplanned System Average Interruption Frequency Index (unplanned SAIFI). SAIFI measures average number of interruptions per customer. Unplanned SAIFI is the total number of unplanned sustained customer interruptions divided by the total number of distribution customers. Unplanned SAIFI excludes momentary interruptions (one minute or less). SAIFI is expressed per 0.01 interruptions.

- Momentary Average Interruption Frequency Index (MAIFI). MAIFI measures average number of momentary interruption per customer. MAIFI is the total number of customer interruptions of one minute or less, divided by the total number of distribution customers.

In Australia, the most common performance indicators for DNSP reliability are SAIDI and SAIFI. They relate to the average duration and frequency of network outages and do not distinguish between the nature and size of affected loads.

Network types

The AER’s STPIS classifies electricity networks into the following four network types:

1. CBD feeder—a feeder supplying predominantly commercial, high-rise buildings, supplied by a predominantly underground distribution network containing significant interconnection and redundancy when compared to urban areas.

2. Urban feeder—a feeder, which is not a CBD feeder, with actual maximum demand over the reporting period per total feeder route length greater than 0.3 MVA/km.

3. Short rural feeder—a feeder which is not a CBD or urban feeder with a total feeder route length less than 200 km.

4. Long rural feeder—a feeder which is not a CBD or urban feeder with a total feeder route length greater than 200 km.

Geographical locations

This section outlines the general geographical locations of the DNSPs' feeders.

ActewAGL
ActewAGL's urban feeders are located throughout the urban developed areas of the ACT while short rural feeders are located outside this area.[50]

Ausgrid
The locations of Ausgrid's feeders are:

- CBD: Sydney City centre.
- Urban: the metropolitan and urban areas of north, south and east Sydney; the residential/commercial areas of the Central Coast; Newcastle and Maitland; and Muswellbrook and Singleton.
- Short rural: Hunter, Newcastle, Central Coast, outer areas of Sydney northern, southern metropolitan areas, and the Sydney East area.
- Long rural: Wollombi, Mt Thorley, Merriwa, and Scone.[51]

Essential Energy
Essential Energy's urban feeders are generally located in larger towns and regional cities. Short rural feeders are located on the fringe areas to major towns and regional cities while long rural feeders are located in lower population density areas of the state.[52]

Endeavour Energy
Endeavour Energy's urban network assets are generally located in Greater Western Sydney and major urban centres such as Wollongong. Endeavour Energy's rural network (almost exclusively rural – short assets) comprises most of the network assets located in the Blue Mountains, Southern Highlands and Illawarra regions outside of the major urban centres.[53]

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[50] ActewAGL, email to AER, 4 October 2011. ActewAGL does not have feeders that are classified as rural long feeders.
[51] Ausgrid, email to AER, 4 October 2011.
[52] Essential Energy, email to AER, 7 October 2011.
[53] Endeavour Energy, email to AER, 8 November 2011.

Reliability in electricity distribution

Distribution outages account for over 90 per cent of the duration of all electricity outages in the NEM. Maintenance practices are an important factor in reducing the number of outages and the time it takes to reconnect supply. DNSPs undertake large maintenance programs that include asset inspections and repairs, vegetation clearing and emergency response.

Ultimately, customers must pay for the cost of investment, maintenance and other solutions needed to deliver a reliable power system. Due to the capital intensive nature of distribution networks, it would be expensive, and inefficient, to try to eliminate every possible interruption by building high levels of redundancy. In addition, the impact of a distribution outage tends to be localised to a part of the network and depends on customer load, the design of the network and the time taken by a DNSP to restore supply after an interruption. For example, the economic impact of a network outage on a CBD feeder is likely to be more severe than the impact of a similar outage on a remote rural feeder where customer bases and loads are more dispersed.

Supply reliability

Based on information from the DNSPs, this section:

- outlines the main causes of unplanned outages and exclusions for 2009–10
- covers reliability in the context of each DNSP by reference to the number and duration of unplanned outages (average, per customer) in the entire network
- covers reliability in the context of each DNSP's network feeder types by reference to the number and duration of unplanned outages (average, per customer).

Causes of supply outages

The largest cause of supply outages was equipment failure. Other major causes of supply outages for the DNSPs were weather events, vegetation and animals.[54]

Exclusions

Exclusions emerge from unforeseen events outside the DNSPs control and can subsequently impact outage and duration data. The DNSPs reported the following events in 2009–10 that would have been classified as exclusions for the purposes of the STPIS:

- ActewAGL reported one major event day (MED) but no other exclusions.
- Ausgrid reported two MEDs and five other exclusions. Of the five other exclusions, two involved load interruptions caused by failure of the shared

[54] Comprehensive information about causes of supply outages in the ACT and NSW during 2009–10 is not provided in this section due to data limitations. The data reported by the DNSPs to the AER has limitations, largely due to the DNSPs not reporting the causes of outages to the AER in a standardised manner in 2009–10 and the difficulty in attributing a cause to supply interruptions.

transmission network and the remaining three exclusions involved load shedding caused by an exercise of obligations under electricity regulations.

- Endeavour Energy did not report any MEDs but reported an exclusion that occurred on 2 July 2009, involving a loss of supply at Bayswater power station.

- Essential Energy reported three MEDs due to transformer failure and storm activity.[55] Essential Energy also reported 46 other exclusions, each involving the failure of the shared transmission network. Ten of the 46 reported exclusions occurred on 26 September 2009 as a result of third party supply loss.

Number and duration of unplanned outages (average, per customer)

Table 5.1 provides reliability information about the DNSPs in terms of the average number of unplanned outages per customer, reflecting the unplanned SAIFI parameter of the STPIS. Figure 5.1 provides the average unplanned minutes off supply per customer, reflecting the unplanned SAIDI parameter of the STPIS. Table 5.1 and figure 5.1 show that on average, after exclusions:

- customers on ActewAGL's network experienced 0.63 unplanned outages and 26.3 minutes off supply due to unplanned outages

- customers on Ausgrid's network experienced 1.06 unplanned outages and 79.9 minutes off supply due to unplanned outages

- customers on Endeavour Energy's network experienced 1 unplanned outage and 79 minutes off supply due to unplanned outages

- customers on Essential Energy's network experienced the highest number of unplanned outages of approximately 1.99 outages and the longest duration of minutes off supply due to unplanned outages of 196 minutes.

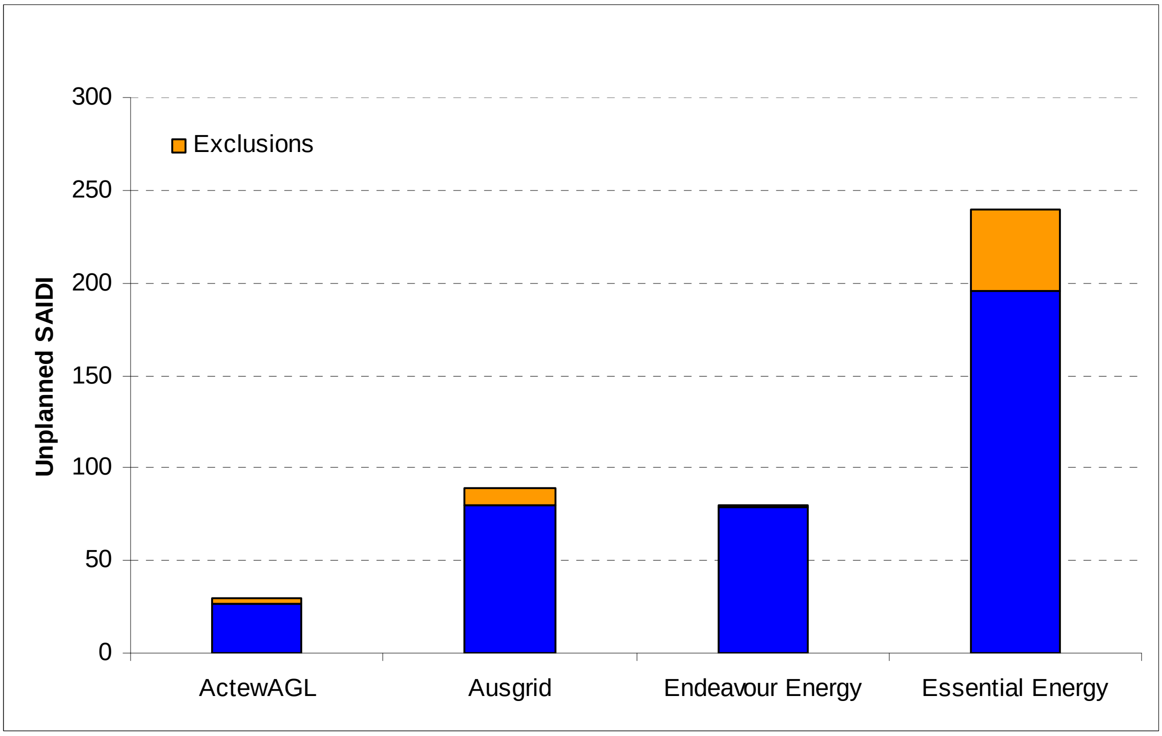
Table 5.1 Average number of unplanned outages per customer (unplanned SAIFI)

DNSP	Unplanned SAIFI (before exclusions)	Unplanned SAIFI (after exclusions)
ActewAGL	0.67	0.63
Ausgrid	1.16	1.06
Endeavour Energy	1	1
Essential Energy	2.28	1.99

Note: The unplanned SAIFI data is affected by potential errors, including ± 5% for ActewAGL, 2% for Ausgrid, 4.3% for Endeavour Energy and 10% for Essential Energy. All DNSPs except for Endeavour Energy reported their SAIFI figures in two decimal places.

55 Country Energy, *Electricity Network Performance Report 2009–10.*

Figure 5.1 Average unplanned minutes off supply per customer (unplanned SAIDI)



Note: The unplanned SAIDI data is affected by potential errors, including ± 10% for ActewAGL, 5% for Ausgrid, 5.5% for Endeavour Energy and 10% for Essential Energy.

Reliability by network feeder type

This section provides reliability information about the DNSPs by network feeder type.

CBD network reliability

In the ACT and NSW, only Ausgrid has CBD feeders as classified under the STPIS. On average, customers on Ausgrid's CBD feeders experienced approximately 0.11 outages and approximately 37 minutes without electricity supply during 2009–10 due to unplanned outages.[56] None of the outages on Ausgrid's CBD feeders in 2009–10 would have been classified as exclusions for the purposes of the STPIS.

Urban network reliability

All of the DNSPs have urban feeders as classified under the STPIS. Table 5.2 shows the average number of unplanned outages experienced by a customer on the DNSPs' urban feeders. Figure 5.2 shows the average unplanned minutes off electricity supply for a customer on the DNSPs' urban feeders. Table 5.2 and figure 5.2 show that on average, after exclusions:

- customers on ActewAGL's urban feeders experienced 0.61 unplanned outages and 25.8 minutes off supply due to unplanned outages
- customers on Ausgrid's urban feeders experienced 0.95 unplanned outages and approximately 67.3 minutes off supply due to unplanned outages

[56] Ausgrid's unplanned SAIDI is affected by a potential error of ± 5 % and Ausgrid's unplanned SAIFI is affected by a potential error of ± 2%.

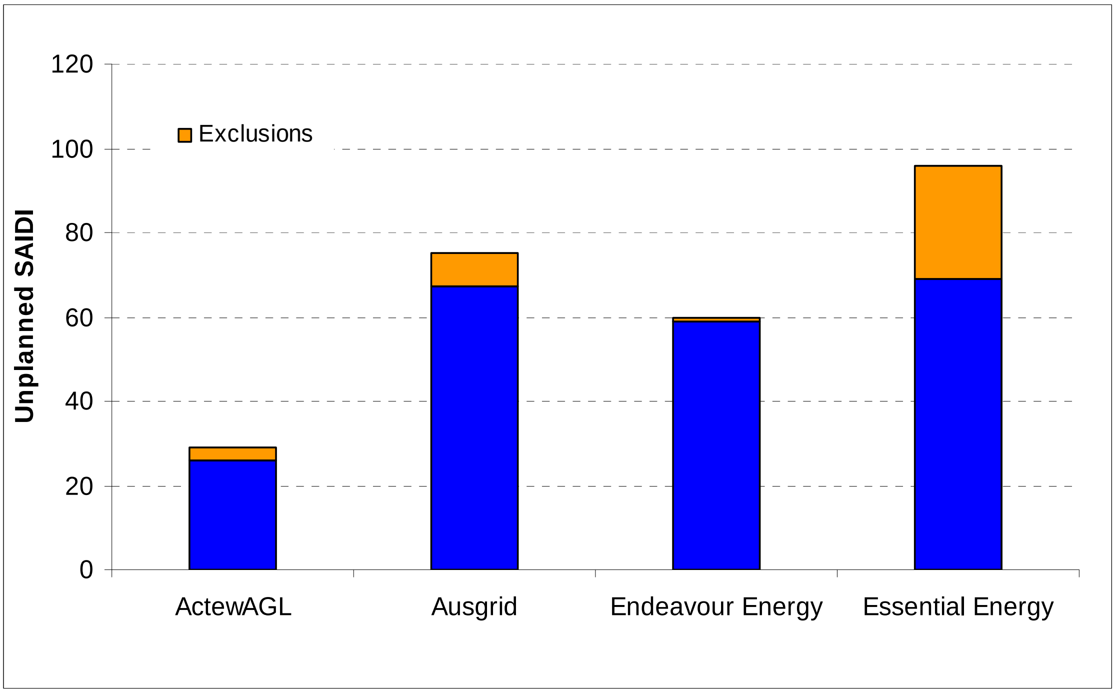
- customers on Endeavour Energy's urban feeders experienced 0.8 unplanned outages and 59 minutes off supply due to unplanned outages
- customers on Essential Energy's urban feeders experienced the highest number of unplanned outages of 1.04 outages and the longest duration of minutes off supply due to unplanned outages of 69 minutes.

Table 5.2 Urban feeders – unplanned SAIFI

DNSP	Unplanned SAIFI (before exclusions)	Unplanned SAIFI (after exclusions)
ActewAGL	0.66	0.61
Ausgrid	1.04	0.95
Endeavour Energy	0.8	0.8
Essential Energy	1.24	1.04

Note: The unplanned SAIFI data is affected by potential errors, including ± 5% for ActewAGL, 2% for Ausgrid, 8.6% for Endeavour Energy and 10% for Essential Energy. All DNSPs except for Endeavour Energy reported their SAIFI figures in two decimal places.

Figure 5.2 Urban feeders – unplanned SAIDI



Note: The unplanned SAIDI data is affected by potential errors, including ± 10% for ActewAGL, 5% for Ausgrid, 9.8% for Endeavour Energy and 10% for Essential Energy.

Rural network reliability: short rural feeders

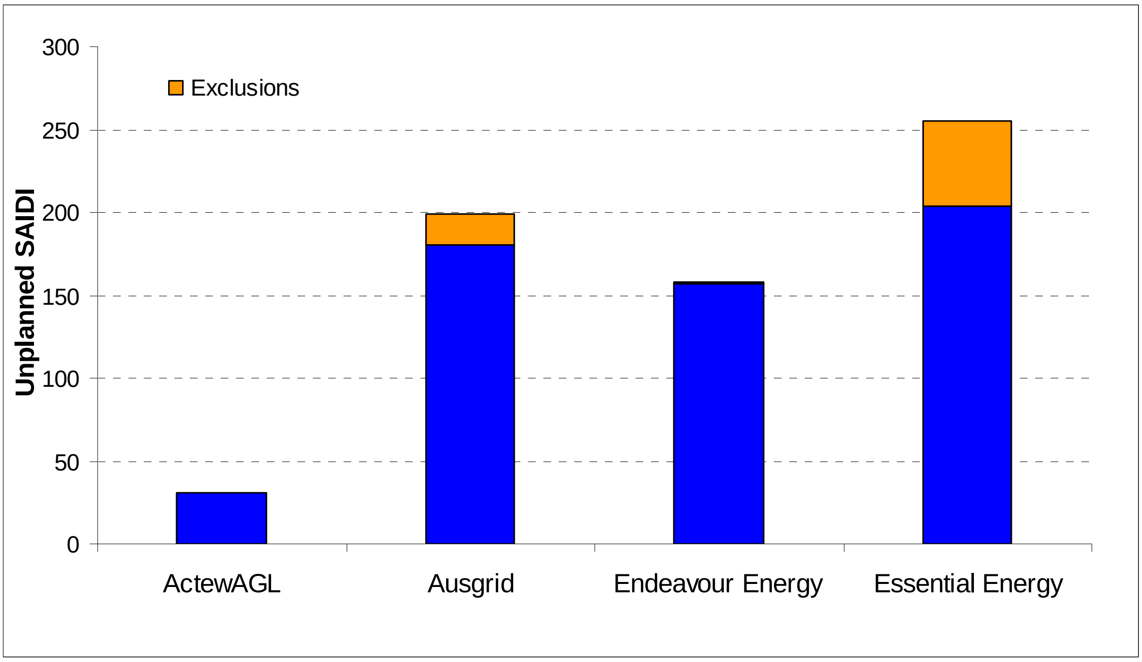
All of the DNSPs have short rural feeders as classified under the STPIS. The average number and minutes of unplanned outages experienced by a customer on the DNSPs' short rural feeders are shown in table 5.3 and figure 5.3.

Table 5.3 Short rural feeders – unplanned SAIFI

DNSP	Unplanned SAIFI (before exclusions)	Unplanned SAIFI (after exclusions)
ActewAGL	0.84	0.84
Ausgrid	2.21	2.03
Endeavour Energy	1.7	1.7
Essential Energy	2.51	2.19

Note: The unplanned SAIFI data is affected by potential errors, including ± 5% for ActewAGL, 2% for Ausgrid, 8.6% for Endeavour Energy and 10% for Essential Energy. All DNSPs except for Endeavour Energy reported their SAIFI figures in two decimal places.

Figure 5.3 Short rural feeders – unplanned SAIDI



Note: The unplanned SAIDI data is affected by potential errors, including ± 10% for ActewAGL, 5% for Ausgrid, 9.8% for Endeavour Energy and 10% for Essential Energy.

Table 5.3 and figure 5.3 show that during 2009–10, on average after exclusions:

- customers on ActewAGL's short rural feeders experienced approximately 0.84 unplanned outages and 30.5 minutes off supply due to unplanned outages
- customers on Ausgrid's short rural feeders experienced approximately 2.03 unplanned outages and 180.32 minutes off supply due to unplanned outages

- customers on Endeavour Energy’s short rural feeders experienced 1.70 unplanned outages and 157 minutes off supply due to unplanned outages

- customers on Essential Energy’s short rural feeders experienced the highest number of unplanned outages of 2.19 unplanned outages and the longest duration of minutes off supply due to unplanned outages of 204 minutes.

Rural network reliability: long rural feeders

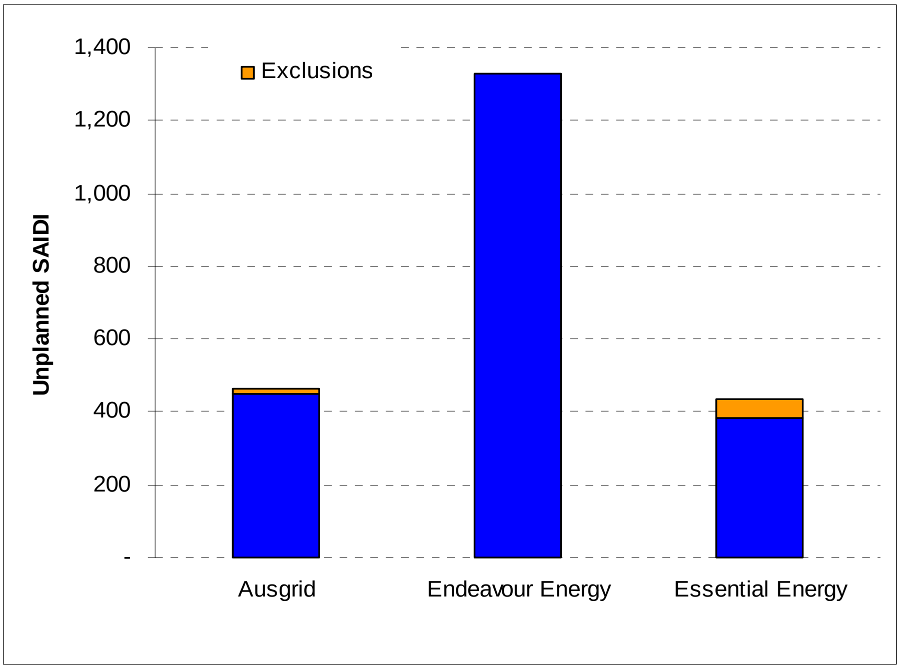
All of the NSW DNSPs have long rural feeders as classified under the STPIS. The average number and minutes of unplanned outages experienced by a customer on the NSW DNSPs’ long rural feeders are shown in table 5.4 and figure 5.4.

Table 5.4 Long rural feeders – unplanned SAIFI

DNSP	Unplanned SAIFI (before exclusions)	Unplanned SAIFI (after exclusions)
Ausgrid	3.63	3.55
Endeavour Energy	8.3	8.3
Essential Energy	3.3	2.88

Note: ActewAGL does not have feeders that are classified as rural long feeders and Endeavour Energy has one feeder that is classified as a rural long feeder. The unplanned SAIFI data is affected by potential errors, including ± 2% for Ausgrid, 8.6% for Endeavour Energy and 10% for Essential Energy.

Figure 5.4 Long rural feeders – unplanned SAIDI



Note: ActewAGL does not have feeders that are classified as rural long feeders and Endeavour Energy has one feeder that is classified as a rural long feeder. The unplanned SAIDI data is affected by potential errors, including ± 5 % for Ausgrid, 9.8% for Endeavour Energy and 10% for Essential Energy.

Table 5.4 and figure 5.4 show that during 2009–10, on average, after exclusions:

- customers on Ausgrid's long rural feeders experienced approximately 3.55 unplanned outages and 448.5 minutes off supply due to unplanned outages

- customers on Endeavour Energy's long rural feeder experienced the highest number of outages of approximately 8.3 unplanned outages and the longest duration of minutes off supply due to unplanned outages of 1331 minutes[57]

- customers on Essential Energy's long rural feeders experienced approximately 2.88 unplanned outages and 384 minutes off supply due to unplanned outages.

Reliability 2005–06 to 2009–10

Figure 5.5 shows the average minutes off supply for a customer on the DNSPs' networks from 2005–06 to 2009–10. Figure 5.6 shows the average number of outages for a customer on the DNSPs' networks from 2005–06 to 2009–10. Appendix D provides further detail about the average number of unplanned outages and average unplanned minutes off supply per customer from 2005–06 to 2009–10.

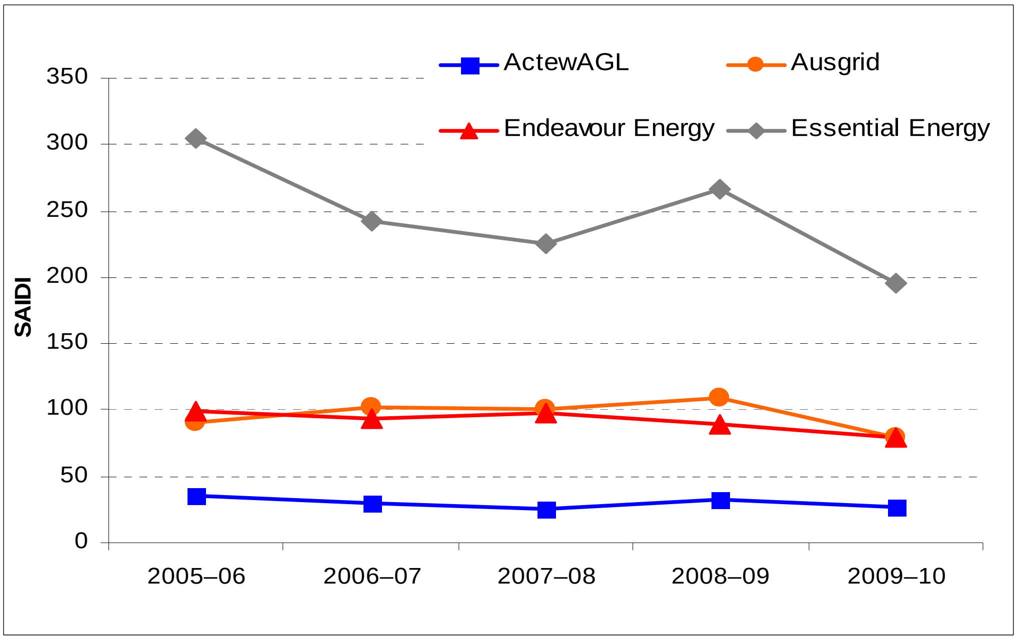
It should be noted that the information presented in figures 5.5 and 5.6 combines information from jurisdictional schemes and the STPIS. The jurisdictional information covers 2005–06 to 2008–09. The AER's service performance information is for 2009–10 only. While the AER and jurisdictional schemes differ in detail and therefore the information is not directly comparable, the figures are presented to provide broad trend information regarding the DNSPs' service performance. Figures 5.5 and 5.6 show that in 2009–10, on average:

- customers on Ausgrid, Endeavour Energy and Essential Energy's networks experienced a lower number of outages and less minutes off supply than they experienced during 2005–06 to 2008–09 due to unplanned outages

- customers on ActewAGL's network also experienced less minutes off supply than they experienced during 2005–06 to 2008–09 due to unplanned outages. Customers on ActewAGL's network have experienced an increase in the number of outages since 2006–07.

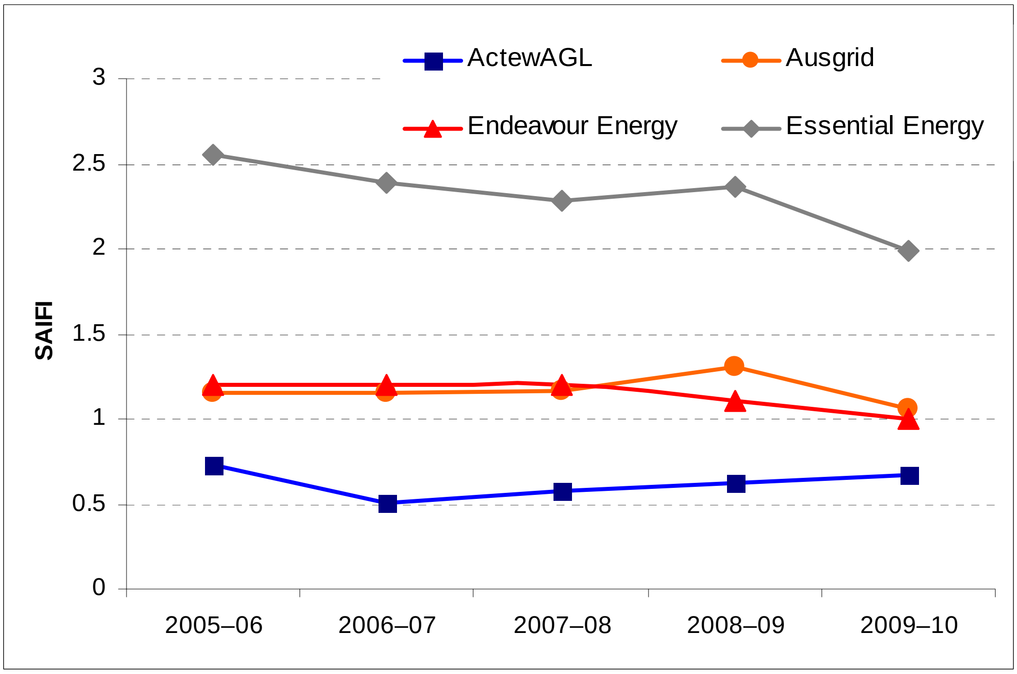
[57] This was due to a storm that occurred on 22 September 2009.

Figure 5.5 Average minutes off supply for 2005–06 to 2009–10



Source: The 2009–10 data is sourced from the DNSPs' RIN responses. The NSW DNSPs 2005–09 data is sourced from their 2009–10 '*Electricity Network Performance*' reports. ActewAGL's 2005–09 data is sourced from its *Annual and Sustainability Report 2009–10*.

Figure 5.6 Average number of outages for 2005–06 to 2009–10



Source: The 2009–10 data is sourced from the DNSPs' RIN responses. The NSW DNSPs 2005–09 data is sourced from their 2009–10 '*Electricity Network Performance*' reports. ActewAGL's 2005–09 data is sourced from its *Annual and Sustainability Report 2009–10*.

5.3 Customer service

This section of the report covers the customer service component of the STPIS and the DNSPs' customer service performance in 2009–10.

Customer service and the STPIS

The STPIS contains customer service parameters relating to telephone answering, streetlight repair, new connections and response to written enquiries. The AER has commenced collecting information from DNSPs in relation to the customer service parameters of the STPIS.

Information about the telephone answering parameter of the STPIS is provided in section 5.3.2 of the STPIS. This report does not cover the streetlight parameter, the new connections parameter or the written enquiries parameter of the STPIS for 2009–10. This information is available from IPART.[58]

During 2009–10 ActewAGL was subject to jurisdictional GSL indicators relating to timely connections and responsiveness to written enquiries and complaints.[59] ActewAGL's streetlight services are not regulated by the AER.

Telephone answering

This section provides information about the DNSPs in relation to their telephone answering in 2009–10. The telephone answering parameter of the STPIS relates to calls to a DNSP's fault line that are answered within 30 seconds.[60]

Figure 5.7 shows the percentage of total calls received by the DNSPs that were not answered within 30 seconds.

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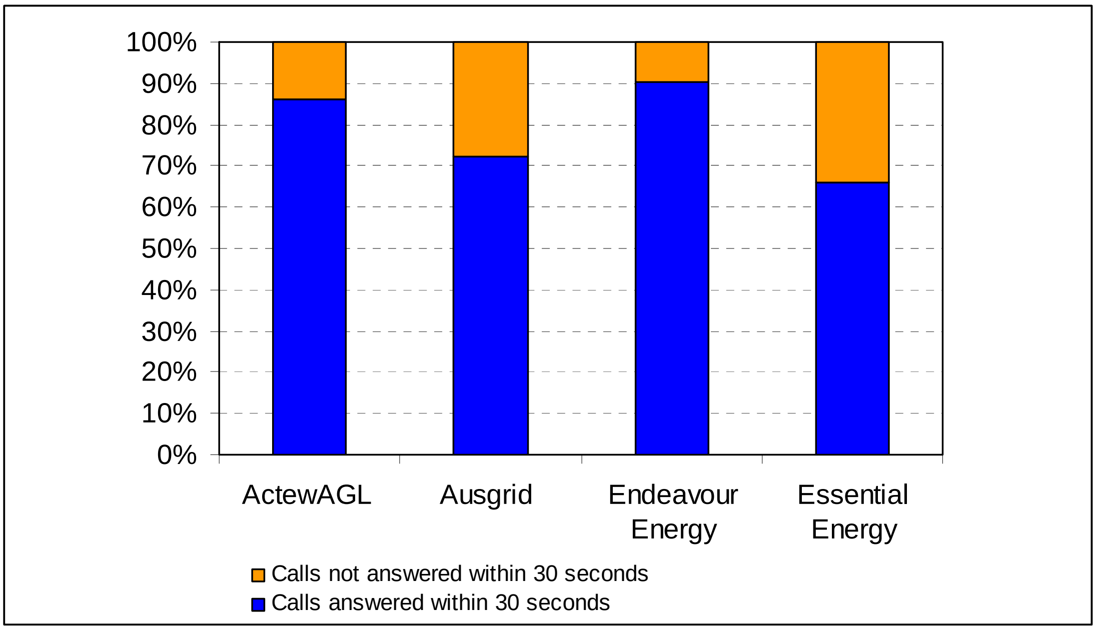
[58] IPART, *Distribution businesses' performance against customer service indicators in NSW for the period 1 July 2005 to 30 June 2010, Electricity — Information Paper*, May 2011.

[59] Consumer Protection Code, January 2007, schedule 1 *and Electricity Supply (General) Regulation 2001*, schedule 3, Part 2.

[60] This is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered) until when the caller speaks with a human operator. It excludes the time that the caller is connected to an automated interactive service that provides substantive information and is measured as a percentage of the total calls received by the DNSP AER, *Electricity distribution network service providers Service target performance incentive scheme,* November 2009, p. 23.

Figure 5.7 DNSPs' telephone answering for 2009–10



Note: This includes excluded events.

Figure 5.7 shows that Essential Energy had the highest percentage of telephone calls that were not answered within 30 seconds (34 per cent), followed by Ausgrid (28 per cent), ActewAGL (14 per cent) and Endeavour Energy (10 per cent).

A. Sources of information and limitations

This appendix discusses the sources of information and limitations of the data.

A.1 Sources of network information and limitations

The data used in this report has been sourced from:

- the DNSPs' 2009–10 regulatory accounts:
    - ActewAGL, *ActewAGL electricity network 2009–10 regulatory accounts*, updated version provided to the AER 4 October 2011
    - Energy Australia, *Regulatory Financial Statements for 2009–10*, 26 October 2010 (updated opex figure provided 18 November 2010)
    - Integral Energy, *Integral Energy 2009–10 Regulatory Accounts*, 24 November 2010
    - Country Energy, *Regulated accounts for 2009–10*, 16 November 2010
- the DNSPs' 2008–09 regulatory accounts:
    - ActewAGL, *ActewAGL 2008–09 Electricity Distribution Reg Accounts*, 1 July 2011
    - Energy Australia, *Energy Australia's FY 2009 regulatory accounts*, 15 December 2009
    - Integral Energy, 2008-09 Integral Energy Regulatory Financial Statements, 9 November 2009
    - Country Energy, 2008/09 Reg Accounts, 5 January 2010
- the DNSPs' 2007–08 regulatory accounts:
    - ActewAGL, *2007–08 ActewAGL electricity distribution report submitted to the ICRC*, 4 August 2011
    - Energy Australia, *Regulatory Financial Statements for 2007–08*, 28 October 2008
    - Integral Energy, *Regulatory Financial Statements for NSW Electricity Distributors and Information Requirement for Pricing Determinations*, 15 April 2011
    - Country Energy, *2007–08 regulatory accounts*, 15 April 2011
- the DNSPs' 2006–07 regulatory accounts:
    - ActewAGL, *Annual Report to the ICRC , Non Technical Electricity Distribution 2006/2007*, 17 March 2008

- Energy Australia, *Regulatory Financial Statements for NSW Electricity Distributors and Information Requirement for Pricing Determinations*, 20 March 2008
- Integral Energy, *Integral Energy 2006/07 Regulatory Financial Statements*, 20 March 2008
- Country Energy, *Regulatory Financial Statements for NSW Electricity Distributors and Information Requirement for Pricing Determinations*, 20 March 2008

- the DNSPs' 2005–06 regulatory accounts:
  - ActewAGL, *Annual Report to the ICRC, Non Technical Electricity Distribution 2005/2006*, 17 March 2008
  - Energy Australia, *Regulatory Financial Statements for 2005–06*, 27 October 2006
  - Integral Energy, *2005/06 Regulatory Financial Statements*, 30 October 2006
  - Country Energy, *Regulatory Financial Statements for NSW Electricity Distributors and Information Requirement for Pricing Determinations*, 20 March 2008
- the DNSPs' Regulatory Information Notice Reponses:
  - ActewAGL, *RIN Response*, 14 April 2011
  - Ausgrid, *Ausgrid response to Regulatory Information Notice issued by AER*, 15 April 2011
  - Endeavour Energy, *AER RIN Incentive Schemes*, 19 April 2011
  - Essential Energy, *Incentive scheme reporting*, 15 April 2011
- the DNSPs' Electricity Network Performance Reports
  - ActewAGL, *Annual and Sustainability Report 2009–10* http://www.actewagl.com.au/About-us/~/media/ActewAGL/ActewAGL-Files/About-us/Publications/Corporate%20and%20legal%20PDFs/ActewAGL-annual-and-sustainability-report-2009-10.ashx
  - Ausgrid, *2009/10 Network Performance Report* http://www.ausgrid.com.au/Common/Our-network/Network-regulation-and reports/~/media/Files/Network/Regulations%20and%20Reports/0910NetworkPerformanceReport.ashx

    - Endeavour Energy, *Electricity Network Performance Report*, http://www.endeavourenergy.com.au/wps/wcm/connect/23a38d004701ab758d0ccf23afe1452b/ENPR+

    - Country Energy, *Electricity Network Performance Report*, http://www.essentialenergy.com.au/asset/cms/pdf/electricitynetwork/CE_NPR_0910.pdf

- the AER's State of the Energy Market Report 2009

- the AER's State of the Energy Market Report 2010

- the AER's 2009–14 distribution determinations for the ACT and NSW DNSPs and the Australian Competition Tribunal's orders available at www.aer.gov.au

- the AER's published Roll Forward Model and Post Tax Revenue Model for each of the DNSPs.

CPI adjustments

The AER has made the following assumptions with respect to the CPI adjustments made in this report:

- actual figures (taken from the regulatory accounts) for the 2009–10 regulatory year are valued in mid year dollar terms, that being the mid point of regulatory year – December 2009

- forecast capex and opex (as reported in the AER's 2009 determination) are valued in end of 2008–09 dollar terms, that being June 2009

- forecast revenue (as reported in the AER's 2009 determination) are valued in end of 2009–10 dollar terms, that being June 2010

- to enable the comparison of like for like figures, forecast figures in this report have been adjusted by half a year's actual CPI to align with actual figures. The CPI used for this adjustment is consistent with that used for pricing purposes for the relevant year.[61]

Differences in DNSP costs

The costs between DNSPs may vary due to differences in:

- the volume of services provided—a DNSP carrying smaller volumes may have higher average costs than a firm carrying higher volumes due to economies of scale

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61 The CPI applied for 2009–10 is 1.82 per cent: sourced from the lagged 2009–10 CPI which was used in the 2010–11 NSW DNSP pricing proposal. Therefore the discount rate that applies from the end of 2009–10 to the mid point of that regulatory year is 1.009059 per cent.

- the quality of services provided—a firm which offers higher reliability may have a higher average cost than a firm which offers lower reliability

- the price of inputs—DNSPs in rural areas may have to pay more to attract skilled labour

- accounting policies—there are differences in capitalisation, cost allocation and other accounting policies for each DNSP. This will affect the comparability of costs between the DNSPs

- classification of services—the types of activities comprising standard control services may differ between DNSPs which will affect the comparability of costs

- the size of geographical area served, customer density and average line length per customer.

The AER aims to gain a detailed understanding of the differences in costs between DNSPs. The AER will continue to implement its networks information and reporting strategy and anticipates that its DNSP performance reports will deliver more comprehensive financial performance information in future.

A.2 Sources of service performance data and limitations

The AER must collect and monitor service performance data from the DNSPs during the 2009–14 regulatory control period in accordance with the NER.[62] The 2009–10 service performance data used in chapter 5 of this report has been sourced from the DNSPs' response to the AER's RINs. This data has limited accuracy and reliability.[63] The AER notes the extent to which the DNSPs were able to provide accurate and reliable data was dependent on the systems and processes that were in place during 2009–10, prior to the AER issuing its data request.

Independent audits of the service performance data showed that for 2009–10:

- ActewAGL's data has potential errors of ± 5 per cent for unplanned SAIFI and ±10 per cent for unplanned SAIDI

- Ausgrid's data has potential errors of ± 2 per cent for unplanned SAIFI and ± 5 per cent for unplanned SAIDI

- Endeavour Energy's data has potential errors of ± 4.3 per cent for unplanned SAIFI, ± 5.5 per cent for unplanned SAIDI, ± 8.6 per cent for unplanned SAIFI by feeder type, and ± 9.8 per cent for unplanned SAIDI by feeder type

- Essential Energy's data has potential errors of ± 10 per cent for unplanned SAIFI and ± 10 per cent for unplanned SAIDI.

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62 Clause 6.6.2(h) of the transitional chapter 6 NER.
63 The AER expected an accuracy assessment of ± 2 per cent for the 2009–10 incentive scheme RINs.

B. General network information

This appendix contains historical (2005–06 to 2008–09) and 2009–10 information on maximum demand, energy delivered, and customer numbers for the DNSPs. It also contains changes in residential and non-residential customer numbers for the DNSPs between 2008–09 and 2009–10.

Table B.1 Maximum demand for 2005–06 to 2009–10 (MW)

	2005–06	2006–07	2007–08	2008–09	2009–10
ActewAGL	617	599	589	607	604
Ausgrid	5 460	5 484	5 683	5 918	5 609
Endeavour Energy	3 649	3 454	3 268	3 798	3 722
Essential Energy	2 230	2 251	2 329	2 332	2 239

Source: Figures are sourced from the DNSPs' 2009–10 regulatory accounts.

Table B.2 Energy delivered for 2005–06 to 2009–10 (GWh)

	2005–06	2006–07	2007–08	2008–09	2009–10
ActewAGL	2773.0	2799.0	2831.0	2879.0	2908.0
Ausgrid	27980.3	28073.3	28279.7	28565.9	28230.1
Endeavour Energy	17196.0	17482.6	18111.7	17426.0	17410.8
Essential Energy	11964.8	11974.1	12036.9	12121.4	12103.5

Source: Figures are sourced from the DNSPs' 2009–10 regulatory accounts. Figures include public lighting customers for the NSW DNSPs.

Table B.3 Customer numbers in 2008–09 to 2009–10

	Residential customers		Non-residential customers		Total Customers	
	2008–09	2009–10	2008–09	2009–10	2008–09	2009–10
ActewAGL		150 445		14 432	161 061	164 900
Ausgrid	1 412 816	1 424 560	178 453	180 972	1 591 372	1 605 635
Endeavour Energy	780 879	786 940	78 840	79 821	859 732	866 767
Essential Energy	663 332	702 585	122 909	95 691	786 321	798 356

Source: Figures are sourced from the DNSPs' 2009–10 regulatory accounts.

Table B.4 Customer numbers for 2005–10

	2005–06	2006–07	2007–08	2008–09	2009–10
ActewAGL	154 510	156 359	158 455	161 061	164 900
Ausgrid	1 556 716	1 568 308	1 580 933	1 591 372	1 605 635
Endeavour Energy	832 956	842 315	852 256	859 732	866 767
Essential Energy	762 722	771 134	780 302	786 321	798 356

Source: Figures are sourced from the DNSPs' 2009–10 regulatory accounts. Customer numbers include public lighting customers (for NSW DNSPs) and un-metered customers (for ActewAGL).

C. Financial performance information

This appendix contains information on forecast and actual capex drivers and forecast and actual opex drivers for each DNSP. It also contains information on the DNSPs' reported revenue, capex, opex and capital contributions for 2006–07 to 2009–10.

C.1 Capex drivers 2009–10

Table C.1.1 ActewAGL capex drivers in 2009–10 ($m)

Driver	Actual capex	Percentage
Asset renewal/replacement	17.3	26.8
Customer initiated (less capital contributions)	17.2	26.7
Augmentation	11.8	18.2
Reliability and quality improvements	0.5	0.7
Network IT systems and communications	1.4	2.1
Non–system assets	16.4	25.3
Total	64.5	100

Note: Totals may not add due to rounding. Capex exclude capital contributions ($6.5m capital contributions deducted from reported customer initiated expenditure). Figures are sourced from ActewAGL's 2009–10 regulatory accounts.

Table C.1.2 Ausgrid capex drivers in 2009–10 ($m)

Driver	Actual capex	Percentage
Asset renewal/replacement	354.3	33.5
Growth (demand related)	460.8	43.6
Reliability and quality of service enhancement	51.0	4.8
Environmental, safety and statutory obligations	32.8	3.1
Non–system assets	158.6	15.0
Total	1057.6	100

Note: Figures are rounded to one decimal place. Capex excludes capital contributions. Figures are sourced from the Ausgrid's 2009–10 regulatory accounts.

Table C.1.3 Endeavour Energy capex drivers in 2009–10 ($m)

Driver	Actual capex	Percentage
Asset renewal/replacement	128.8	32.1
Growth (demand related)	149.5	37.2
Reliability and quality of service enhancement	12.4	3.1
Environmental, safety and statutory obligations	71.0	17.7
Non–system assets	39.9	9.9
Total	401.6	100

Note: Figures are rounded to one decimal place and exclude capital contributions. Figures are sourced from Endeavour Energy's 2009–10 regulatory accounts.

Table C.1.4 Essential Energy capex drivers in 2009–10 ($m)

Driver	Actual capex	Percentage
Asset renewal/replacement	154.0	23.6
Growth (demand related)	254.4	39.0
Reliability and quality of service enhancement	100.4	15.4
Environmental, safety and statutory obligations	12.3	1.8
Non–system assets	131.9	20.2
Total	652.8	100

Note: Figures are rounded to one decimal place and exclude capital contributions. Figures are sourced from Essential Energy's 2009–10 regulatory accounts.

C.2 2009–10 opex drivers

Table C.2.1 ActewAGL opex drivers in 2009–10 ($m)

Driver	Actual opex	Percentage
Feed–in tariff	1.2	2.0
Utilities network facilities tax	4.1	6.7
Network operating expenditure	17.4	28.6
Zone substation maintenance	2.2	3.6
Sub transmission maintenance	0.9	1.5
Underground maintenance	1.8	3.0
Overhead maintenance	9.6	15.8
Distribution station maintenance	2.0	3.3
Other operating costs	21.6	35.5
Total	60.8	100

Note: Figures are rounded to one decimal place and are sourced from ActewAGL's 2009–10 regulatory accounts.

Table C.2.2 Ausgrid opex drivers in 2009–10 ($m)

Driver	Actual opex	Percentage
Network operating costs	62.7	12.2
Maintenance costs – inspection	85.5	16.8
Maintenance costs – repair	70.7	13.9
Maintenance costs – vegetation management	36.5	7.2
Maintenance costs – emergency response	61.9	12.1
Other operating and maintenance costs	192.7	37.8
Total	510.0	100

Note: Figures are rounded to one decimal place and are sourced from Ausgrid's 2009–10 regulatory accounts.

Table C.2.3 Endeavour Energy opex drivers in 2009–10 ($m)

Driver	Actual opex	Percentage
Network operating costs	63.1	24.6
Maintenance costs – inspection	19.9	7.8
Maintenance costs – repair	51.0	20.0
Maintenance costs – vegetation management	37.1	14.5
Maintenance costs – emergency response	24.4	9.5
Maintenance costs – other	4.9	1.9
Other operating costs	56.0	21.8
Total	256.3	100

Note: Figures are rounded to one decimal place. Figures are sourced from the Endeavour Energy's 2009–10 regulatory accounts.

Table C.2.4 Essential Energy opex drivers in 2009–10 ($m)

Driver	Actual opex	Percentage
Network operating costs	13.2	3.6
Maintenance costs – inspection	34.5	9.4
Maintenance costs – repair	77.7	21.2
Maintenance costs – vegetation management	90.9	24.8
Maintenance costs – emergency response	70.2	19.1
Other costs	80.7	22.0
Total	367.1	100

Note: Figures are rounded to one decimal place and are sourced from Essential Energy's 2009–10 regulatory accounts

C.3 Revenue, capex and opex

Table C.3.1 ActewAGL – revenue, capex, opex and capital contributions ($m, 2009–10)

	2006–07	2007–08	2008–09	2009–10
Reported revenue	128.7	135.0	139.0	142.3
Reported capex	35.7	39.4	40.0	64.5
Reported opex	47.2	40.7	49.9	60.7
Reported opex for EBSS purposes				50.4
Reported capital contributions	4.5	5.8	8.8	6.5

Note: Figures are rounded to one decimal place and are sourced from ActewAGL's regulatory accounts.

Table C.3.2 Ausgrid – revenue, capex, opex and capital contribution ($m, 2009–10)

	2006–07	2007–08	2008–09	2009–10
Reported revenue	971.4	1017.3	1076.7	1257.6
Reported capex	792.2	862.8	1187.2	1057.6
Reported opex	354.8	498.3	462.0	510.0
Reported opex for EBSS purposes				497.0
Reported capital contributions	60.9	58.0	56.1	47.0

Note: Figures are rounded to one decimal place and are sourced from Ausgrid's regulatory accounts. EBSS includes transmission.

Table C.3.3 Endeavour Energy – revenue, capex, opex and capital contributions ($m, 2009–10)

	2006–07	2007–08	2008–09	2009–10
Reported revenue	622.4	680.7	701.9	777.7
Reported capex	405.6	385.7	445.9	401.6
Reported opex	236.6	290.0	270.6	256.3
Reported opex for EBSS purposes				242.0
Reported capital contributions[64]	60.1	60.5	58.4	44.1

Note: Figures are rounded to one decimal place and are sourced from Endeavour Energy's regulatory accounts.

[64] Cash contributions are not included as they do not form part of the asset balance.

Table C.3.4 Essential Energy – revenue, capex, opex and capital contributions ($m, 2009–10)

	2006–07	2007–08	2008–09	2009–10
Reported revenue	894.4	748.5	795.7	894.3
Reported capex	482.8	522.8	586.2	652.8
Reported opex	327.5	369.9	352.9	367.1
Reported opex for EBSS purposes				359.4
Reported capital contributions	77.9	80.0	92.1	81.1

Note: Figures are rounded to one decimal place and are sourced from Essential Energy's regulatory accounts.

D. Service performance information

This appendix contains information on service performance information, particularly the DNSPs' historical SAIDI and SAIFI for 2005–06 to 2008–09 and their telephone answering performance in 2009–10.

Table D.1 ActewAGL historical SAIDI and SAIFI for 2005–06 to 2009–10

	2005–06	2006–07	2007–08	2008–09	2009–10
SAIDI	35.6	30.1	26.1	33.1	26.3
SAIFI	0.73	0.51	0.58	0.62	0.67

Source: The 2005–06 to 2008–09 figures are sourced from ActewAGL's *Annual and Sustainability Report 2009–10*. The 2009–10 figures are sourced from the ActewAGL's RIN response, reflecting the STPIS. All figures are for unplanned outages.

Table D.2 Ausgrid historical SAIDI and SAIFI for 2005–06 to 2009–10

	2005–06	2006–07	2007–08	2008–09	2009–10
SAIDI	90.2	102.0	100.3	108.5	79.9
SAIFI	1.15	1.15	1.16	1.31	1.06

Source: The 2005–06 to 2008–09 are sourced from Ausgrid's *2009/10 Network Performance Report*. These figures were normalised using the beta-exclusion method. The 2009–10 figures are sourced from the Ausgrid's RIN response, reflecting the STPIS. All figures are for unplanned outages.

Table D.3 Endeavour Energy historical SAIDI and SAIFI for 2005–06 to 2009–10

	2005–06	2006–07	2007–08	2008–09	2009–10
SAIDI	99	94	98	89	79
SAIFI	1.2	1.2	1.2	1.1	1.0

Source: The 2005–06 to 2008–09 figures are sourced from Endeavour Energy's *2009–10 Electricity Network Performance Report*. These figures were normalised using the beta-exclusion method. The 2009–10 figures are sourced from the Endeavour Energy's RIN response, reflecting the STPIS. All figures are for unplanned outages.

Table D.4 Essential Energy historical SAIDI and SAIFI for 2005–06 to 2009–10

	2005–06	2006–07	2007–08	2008–09	2009–10
SAIDI	304	242	225	267	196
SAIFI	2.55	2.39	2.28	2.37	1.99

Source: The 2005–06 to 2008–09 figures are sourced from Essential Energy's *2009–10 Electricity Network Performance Report*. These figures were normalised using the beta-exclusion method. The 2009–10 figures are sourced from the Essential Energy's RIN response, reflecting the STPIS. All figures are for unplanned outages.

Table D.5 Telephone answering performance in 2009–10

	Total calls without exclusions	Total calls with exclusions	Calls answered within 30 sec	Calls not answered within 30 sec	% calls answered within 30 sec
ActewAGL	41 970	41 449	35 621	5 828	85.94
Ausgrid	200 780	198 260	143 297	54 963	72.28
Endeavour Energy	114 043	114 043	102836	11 207	90.17
Essential Energy	414 217	414 217	273 479	140 738	66.02

Source: Figures were reported under the AER's reporting framework, reflecting the STPIS.

E. Demand Management Incentive Scheme Information

This appendix:

- provides an overview of the AER's demand management incentive scheme (DMIS) for the ACT and NSW 2009 distribution determinations
- outlines the AER's assessment of ActewAGL's and Essential Energy's DMIA expenditure for 2009–10[65]
- attaches ActewAGL's and Essential Energy's DMIS reports to provide information to stakeholders about the results of projects and programs.

E.1 Overview of the DMIS

The AER published its DMIS in November 2008 in accordance with the NER.[66] The DMIS aims to provide incentives for DNSPs to conduct research and investigation into innovative techniques for managing demand so that in the future, demand management projects may be increasingly identified as viable alternatives to network augmentation. The DMIS consists of two parts – Part A and Part B.

Part A of the DMIS is the DMIA which is provided to the DNSP as an annual allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year of the 2009–14 regulatory control period. In the second regulatory year of the subsequent regulatory control period, when results for the first to fifth regulatory years of the 2009–14 regulatory control period are known, a single adjustment will be made to return the amount of any underspend or unapproved amounts to customers. This ensures that the scheme remains neutral in terms of the expenditure profile which the DNSP adopts during the regulatory control period.

Under Part A of the DMIS the AER approved the following allowances for the 2009–14 regulatory control period: $100 000 per annum for ActewAGL; $1 million per annum for Ausgrid; $600 000 per annum for Endeavour Energy; and $600 000 per annum for Essential Energy. The DMIA dollar amounts are broadly proportional to the relative sizes of the DNSPs' annual revenues. Part A of the DMIS contains annual reporting requirements for DNSPs for the 2009–14 regulatory control period. The information provided in a DNSP's annual DMIS report is used in the AER's assessment of a DNSP's compliance with the DMIA criteria and entitlement to recover expenditure under the DMIA.

Part B of the DMIS relates to forgone revenue. The AER did not apply Part B of the DMIS in the 2009–14 distribution determinations for the ACT and NSW DNSPs. However, the AER's 2009 NSW determination applied IPART's D–factor scheme to Ausgrid, Endeavour Energy and Essential Energy.[67] The D–factor scheme allows the NSW DNSPs to recover costs incurred and revenues foregone as a result of certain

[65] Ausgrid and Endeavour Energy did not claim DMIA for 2009–10.
[66] Clause 6.6.3 of the transitional chapter 6 of the NER.
[67] IPART, *Guidelines on the Application of the D–factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination.*

demand management activities. The D–factor operates as an input into the WAPC on a two year lag basis (as costs and foregone revenues are not reported until the end of the financial year after the projects are undertaken). The 2009–10 D–factors therefore represent costs incurred and revenues foregone by the DNSPs for projects undertaken in 2007–08.

Table E.1 AER decision on 2009–10 D–factors ($)

DNSP	No. of projects	Total costs	Foregone revenue	Avoided distribution cost	D-factor unrounded	D-factor rounded
Ausgrid	17	334 753	1 986 629	14 067 389	0.000169	0.000
Endeavour Energy	14	2 275 385	1 123 235	18 695 000	0.004291	0.004
Essential Energy	1	0	15 205	118 020	0.000039	0.000

In March 2009 the AER reviewed the D–factor applications from the NSW DNSPs. Table E.1 shows the AER's decision on the NSW DNSPs 2009–10 D–factor applications. It should be noted that positive D–factors result in price increases. For example a 0.001 D–factor increases the WAPC by 0.1 per cent.

E.2 DMIA assessment

The AER conducted ActewAGL's and Essential Energy's 2009–10 DMIA compliance assessment based on the annual DMIS reports it received from the businesses. Ausgrid and Endeavour Energy did not claim DMIA in 2009–10. Table E.2 shows the amount of DMIA expenditure approved by the AER for ActewAGL and Essential Energy for 2009–10 and the remaining allowance for each DNSP for the 2009–14 regulatory control period.

Table E.2 DMIA claimed in 2009–10, DMIA approved in 2009–10 and DMIA remaining ($nominal)

DNSP	DMIA claimed	DMIA approved by the AER	DMIA remaining for 2009–14
ActewAGL	28 640	28 640	471 360
Ausgrid	-	-	5 000 000
Endeavour Energy	-	-	3 000 000
Essential Energy	312 885	312 885	2 687 115

ActewAGL's DMIA for 2009–10

ActewAGL claimed DMIA expenditure for its Power Factor Correction (PFC) project in 2009–10. ActewAGL stated that its PFC project aims to reduce demand for standard control services for large commercial customers who record 15 minute interval consumption data across its network. Details about this project can be found in ActewAGL's DMIS report which can be found at appendix F. The AER approved ActewAGL's claimed DMIA expenditure for 2009–10 because it meets the DMIA criteria as set out in table E.2.

Essential Energy's DMIA for 2009–10

Essential Energy claimed DMIA expenditure for its Grid Interactive Inverter (GII) project in 2009–10. Essential Energy stated that its GII project aims to address specific network constraints by reducing demand on or providing reactive support to its network at the time and location of the constraint. Details about the GII project can be found in Essential Energy's DMIS report which are at appendix F. The AER approved Essential Energy's claimed DMIA expenditure for 2009–10 because Essential Energy's GII project meets the DMIA criteria as set out in table E.3.

Table E.3 AER assessment of ActewAGL's DMIA expenditure (2009–10)

DMIS criterion	Reason for approval
Demand management projects or programs are measures undertaken by a DNSP to meet customer demand by shifting or reducing demand for standard control services through non–network alternatives or the management of demand in some other way rather than increasing supply through network augmentation.	ActewAGL's PFC project is consistent with this criterion because it is a measure undertaken by ActewAGL to meet large commercial customer demand which intends to reduce peak apparent demand on commercial feeders. ActewAGL's PFC project aims to reduce demand for standard control services through non–network alternatives by identifying customers for whom suitable power factor correction equipment may be installed.
Demand management projects or programs may be: a. broad–based demand management projects or programs—which aim to reduce demand for standard control services across a DNSP's network, rather than at a specific point on the network. These may be projects targeted at particular network users, such as residential or commercial customers, and may include energy efficiency programs, and/or b. peak demand management projects or programs—which aim to address specific network constraints by reducing demand on the network at the location and time of the constraint.	ActewAGL's PFC project is consistent with this criterion because it is a broad based demand management project which aims to reduce demand for standard control services for large commercial customers.
Demand management projects or programs may be innovative, and designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts.	ActewAGL's PFC project is consistent with this criterion because it will explore potentially efficient demand management mechanisms in terms of power factor correction equipment installation in existing premises.
Recoverable projects and programs may be tariff or non–tariff based.	ActewAGL's PFC project is tariff based.
Costs recovered under this scheme: a. must not be recoverable under any other jurisdictional incentive scheme b. must not be recoverable under any other state or Australian Government scheme c. must not be included in forecast capital or operating expenditure approved in the distribution determination for the next regulatory control period, or under any other incentive scheme in that determination.	ActewAGL's DMIA report for the PFC project contains a statement to this effect.
Expenditure under the DMIA can be in the nature of capex or opex.	ActewAGL has claimed DMIA expenditure for the PFC project as opex.

Table E.4 AER assessment of Essential Energy's DMIA expenditure (2009–10)

DMIA criteria	Reason for approval
Demand management projects or programs are measures undertaken by a DNSP to meet customer demand by shifting or reducing demand for standard control services through non–network alternatives or the management of demand in some other way rather than increasing supply through network augmentation.	Essential Energy's GII project is consistent with this criterion because it is a measure undertaken by Essential Energy to reduce demand for standard control services through non-network alternatives by developing enabling technology aimed at reducing demand on or providing reactive support to the network.
Demand management projects or programs may be: a. broad-based demand management projects or programs—which aim to reduce demand for standard control services across a DNSP's network, rather than at a specific point on the network. These may be projects targeted at particular network users, such as residential or commercial customers, and may include energy efficiency programs, and/or b. peak demand management projects or programs—which aim to address specific network constraints by reducing demand on the network at the location and time of the constraint.	Essential Energy's GII project is consistent with this criterion because it aims to address specific network constraints by reducing demand on or providing reactive support to the network at the time and location of the constraint.
Demand management projects or programs may be innovative, and designed to build demand management capability and capacity and explore potentially efficient demand management mechanisms, including but not limited to new or original concepts.	Essential Energy's GII project is consistent with this criterion because it may explore potentially efficient demand management technology.
Recoverable projects and programs may be tariff or non–tariff based.	Essential Energy's GII project is non–tariff based.
Costs recovered under this scheme: a. must not be recoverable under any other jurisdictional incentive scheme b. must not be recoverable under any other state or Australian Government scheme c. must not be included in forecast capital or operating expenditure approved in the distribution determination for the next regulatory control period, or under any other incentive scheme in that determination.	Essential Energy's DMIA report for the GII project contains a statement to this effect.
Expenditure under the DMIA can be in the nature of capex or opex.	Essential Energy has claimed DMIA expenditure for the GII project as capex.

F. DNSPs' 2009–10 DMIA reports

This appendix contains the DNSPs' DMIA reports.

ActewAGL's DMIA report 2009–10

ActewAGL

Demand Management Incentive Scheme

Power Factor Correction Project

2009-2010

Veronica Grace, Brad Smith, Janusz Worony
Initial Release
Effective date: 14 February 2011

ActewAGL

Contents

ActewAGL

1. Introduction

During the fiscal year 2009-2010, ActewAGL Distribution evaluated options for demand management in accordance with the Demand management incentive scheme for the ACT and NSW 2009 distribution determinations released November 2008. A Power Factor Correction (PFC) Project was selected as the most suitable option for this scheme and development work progressed toward this end.

2. Project Costs

The total amount spent on the PFC project during 2009-2010, as reported in Table 1, DMIA Annual Report, is $28,640. Costs incurred are from direct labour and overhead costs associated with one engineer over fourteen weeks. The calculation of costs is automatically tied to actual hours worked, gross earnings and established overhead rates.

3. Project Nature and Scope

The PFC Project is intended to reduce the reactive power consumption of large commercial customers whom record fifteen minute interval consumption data. Of these customers, ActewAGL Distribution will identify customers with power factors at peak load less than 0.9 whom are on network tariffs (which include a demand component). ActewAGL Distribution will then determine, for each identified customer, suitable power factor correction equipment which, when installed, will reduce their demand tariff.

ActewAGL Distribution will define specifications for power factor correction equipment. The intention, at this point, is to develop wholesale contracts with multiple suppliers to reduce equipment costs. At least a portion of the equipment and installation cost will be funded by the customer. Financial subsidies may be provided to customers with longer payback periods; the threshold is yet to be established.

For each identified customer, ActewAGL Distribution will develop an individual communication regarding their consumption and compensation requirements. This communication will describe the demand component of the network tariff as well as the reactive compensation required to achieve a 0.9 power factor at peak load. The communication will also recommend the procurement and installation of appropriate power factor correction equipment and the associated cost estimates. Additionally, ActewAGL Distribution will communicate the respective demand tariff savings and payback period associated with the installation of the recommended power factor correction equipment.

ActewAGL Distribution is also considering the implementation of a kVAr charge which would financially penalise customers with excessive kVAr consumption. Implementation of this charge may increase the likelihood of customer participation in the PFC Project.

4. Project Aims and Expectations

The primary objective of this project is to reduce the peak apparent demand of commercial feeders within the ActewAGL Distribution network. Preliminary modelling of the potential peak demand reduction was undertaken during the development phase of this project. This modelling indicates feeder peak demand reduction of 4 to 6 MVA is possible if the program enrols the identified 123 customers with the largest reactive compensation requirements.

The actual demand reduction will depend upon the customer participation rate. Including a financial subsidy for customers with longer payback periods may significantly increase the participation rate resulting in increased demand reduction.

In addition to increasing awareness of the identified customers, this program will also increase the awareness within ActewAGL Distribution. Implementation of this program will provide ActewAGL Distribution staff with knowledge that can be transferred immediately to the evaluation of other, existing customers. Additionally, this knowledge can be utilised during the evaluation of new customers. In this case, ActewAGL Distribution may implement a process to estimate the uncompensated peak load power factor of new developments and enforce compliance with the 0.9 power factor requirement prior to site commission.

As a result of this program, ActewAGL Distribution will gain valuable experience and knowledge of power factor correction equipment installation in existing premises.

5. Project Business Case

5.1 Option Selection Criteria

Four demand management project options were considered. Selection of the project was based on the following criteria:

1. Estimated cost;
2. Potential magnitude of the total demand reduction achieved within the $500,000 allocation; and
3. Permanency and reliability of the project.

5.2 Option 1: Power Factor Correction Equipment

This project concept includes the partial subsidisation of power factor correction equipment and installation for commercial customers where a benefit is identified.

This project assumes the full enrolment of 123 customers identified with the largest reactive compensation requirements. In this case, 4-6 MVA of feeder peak demand reduction may be possible. This project does provide a relatively permanent and reliable solution.

5. 3 Option 2: LED Replacements

This project concept includes the subsidised replacement of halogen down lights with LED alternatives. This project concept targets large commercial customers in an effort to maximize concentrated demand reduction.

Current costs of LED retrofit options indicate the cost of demand reduction is approximately $1750/ kW. Utilising the full $100,000/ annum allowance and assuming a 100% subsidy, the total demand reduction attainable is limited to 57 kW/ annum. The project does provide a relatively permanent and reliable solution.

5. 4 Option 3: Commercial Load Curtailment

This project concept includes monitoring and generation of a signal from the ActewAGL Distribution network to the Building Management System (BMS) of large commercial buildings to initiate a reduction in the load of that building for a determined period of time.

The estimated cost of the demand reduction via this project is relatively high at $260 to $540 per kVA. This cost is very difficult to estimate including the costs to enrol building owners/ managers and the ongoing costs associated with the interface. The total demand reduction is also very difficult to predict as the project is highly dependent upon building owner/ manager participation. As there is very minimal financial benefit and several dis-benefits to building owners/ managers, there is concern that participation rate may be low. While a robust interface will provide sufficient reliability, the demand reduction associated with this project is deemed temporary.

5.5 Option 4: Residential Interval Meters

This project concept includes the subsidised installation of interval meters in residential premises to facilitate customer transition to a time of use (TOU) network tariff. The transition to a TOU network tariff increases customer awareness and provides financial incentive to customers to reduce consumption during peak times.

At a cost of $150 per meter for equipment and installation, approximately 666 meters could be subsidised within this project. The total demand reduction, however, is difficult to predict. Because large customers with consumption > 100MWh per annum are currently required to have TOU meters installed, this project targets residential customers only. Therefore, this project does not address the commercial peak demand which presents greater and more localised peak loads. Additionally, the permanency and reliability of peak demand reduction associated with this project is difficult to predict.

5.6 Selected Option

The PFC Project is determined the most suitable option. The PFC Project has the best potential cost per kVA of network demand reduction. Therefore, the PFC Project has the highest likelihood of producing a noticeable demand reduction. All project concepts were developed based upon cost allocation of the $100,000 allowance. With this fixed funding, each project was considered with respect to the total potential demand reduction. In this case, the PFC Project was deemed the most suitable option. The PFC Project provides a permanent and reliable solution, assuming minimal ongoing equipment monitoring and maintenance by the customer.

In addition to the selection criteria, the PFC Project provides the following advantages over the other project concepts:

- The magnitude of the demand reduction is predictable.
- The likelihood of achieving a noticeable demand reduction is high.
- There is minimal impact to customer operation.
- The project can be managed with minimal administration.

6. Project Implementation Plan

Implementation of the PFC Project is simplified into the following steps:

1. Identify customers suitable for the project.
2. Compile detailed information on the real, reactive and apparent power consumptions of each identified customer.
3. From the load profiles, estimate the required reactive compensation magnitude, associated peak apparent power demand reduction and the corresponding savings on the demand tariff associated with the network component of the customer's bill.
4. From the cumulative estimates, determine a payback period threshold, for example 2.5 years, where a financial subsidy will be offered.
5. Initiate a tender process to establish wholesale contracts via multiple suppliers for PFC equipment procurement.
6. Develop individual communications for all identified customers. Inform customers of their obligations regarding compensation requirements. Inform customers of their respective demand tariff savings and payback period associated with the installation of the recommended PFC equipment.

7. Project Implementation Costs

The project scope and delivery is based upon the fixed cost allocation of $100,000/ annum or $500,000 total. Project costs include the following components:

1. ActewAGL Distribution project management
2. Equipment/ installation subsidies to customers.

Project management is estimated at $100,000. Of this, $28,640 has been allocated to the project concept development and is submitted to the AER for the 2009-2010 financial year.

Equipment/ installation subsidies to identified customers are estimated at $400,000. This allocation will provide financial incentive to identified customers and, in some cases, reduce the customer payback period.

8. Identifiable Benefits

Since developing the project concepts, no identifiable benefits have been achieved. The project has not yet entered the implementation phase.

9. Completed Projects Overview

No projects have been completed under this scheme.

10. Funding Sources

Costs associated with this project are not:

(a) recoverable under any other jurisdictional incentive scheme;

(b) recoverable under any other Commonwealth or State Government scheme; or

(c) included in the forecast capex or forecast opex allowances or any other incentive scheme.

Essential Energy's DMIA report 2009–10

Attachment B - DMIA

Country Energy response to Regulatory Information Notice Under Division 4 of Part 3 of the National Electricity (NSW) Law

1.5 In respect of the DMIS:

(a) provide an explanation of each demand management project or program for which approval is sought;

GRID INTERACTIVE INVERTER PROJECT

The project involves the development and field testing of a four quadrant inverter as an enabling technology for energy storage and reactive power support which can be utilised to avoid or defer network augmentation in the low and medium voltage distribution networks.

An electricity network has real and reactive characteristics which interact with real and reactive power flows to determine the levels of voltage, current and losses around the network. The network's capacity to deliver load or absorb generation at any point can be constrained either by current rating of elements in the supply path or unacceptable voltage conditions for customers. Traditional network solutions involve augmentation to increase the supply capacity through upgrading existing infrastructure or providing additional infrastructure to reduce the impedance of the supply path.

A four quadrant inverter is capable of providing a combination of real and reactive power either into or out of the network. This capability can be used to adjust power flows and significantly improve voltages, currents and losses on the existing infrastructure as an alternative to network augmentation. The outcome will be improved utilisation of existing infrastructure and avoidance or deferral of network augmentation

(b) explain, for each demand management project or program identified in the response to paragraph 1.5(a), how it complies with the DMIA criteria detailed at section 3.1.3 of the DMIS, with particular reference to:

(i) the nature and scope of each demand management project or program;

This is a non-tariff based project to develop an enabling technology aimed at addressing specific network constraints by reducing demand on or providing reactive support to the network at the time and location of the constraint.

Four quadrant power electronics technology is currently used extensively in high power, high voltage network applications for static VAr compensation and large energy storage applications However there is no low cost, commercially available equivalent for low power, low voltage or single phase systems and the aim of this project is to fill that gap.

(ii) **the aims and expectations of each demand management project or program;**

The aim of the project is to develop a cost effective, flexible, low voltage, four quadrant inverter which can be used in a variety of applications to address a range of supply quality issues (see appendix A)

It is expected that final production cost for a single phase inverter will be in the order of $500 per kVA which compares favourably to commercially available small scale photovoltaic units offering substantially less functionality.

Energy storage costs are estimated to be $500 per kWh based on currently available lead acid technology, however it is expected that battery development for electric vehicles will ultimately provide a more cost effective alternative.

(iii) **the process by which each demand management project or program was selected, including the business case for the demand management project and consideration of any alternatives;**

Country Energy has a substantial rural distribution network, much of which was installed in the 1950s, 1960s and 1970s under various Rural Electrification Schemes using small section conductor on single phase and SWER construction in order to minimise cost to the customer. The capacity of these lines to supply load or absorb generation is limited (See appendix B)

Subsequent changes to system loads through "infilling" and increased demands of individual installations due to changes in lifestyle and price accessibility of electrical appliances has created many situations throughout Country Energy where general voltage levels cannot be satisfactorily maintained within the allowable voltage range and short term fluctuations create increasing annoyance for customers.

Traditional network solutions include the installation of voltage regulators to address general voltage levels or conductor upgrades in situations where voltage regulation is not an effective option. Current costing for conductor upgrades is in the order of $5,000 per km for SWER and $6,000 for single phase lines and significant distances are involved if an effective improvement in voltage conditions is to be achieved.

While the initial focus of the project was on a modular 20 kVA unit to address feeder level issues the four quadrant capability can also be utilised for power quality improvement on low voltage systems. to mitigate voltage drops due to increased circuit loading or voltage rises due to increasing levels of small scale embedded generation.

Low voltage network solutions include conductor upgrades or additional distribution substations. Depending on the circumstances this could typically cost between $20,000 and $200,000 to address a single constraint.

Country Energy considered the following options:

- **Traditional generation** – An alternative is to use an embedded generator at the end of the affected feeder to reduce the load the feeder needs to supply but traditional generators are often difficult to implement as they have issues with noise, pollution, security and maintenance.

- **Adaptation of commercially available inverter equipment** – The use of commercially available inverters as used for the connection of small scale wind and photovoltaic generation has previously been considered. A trial installation at Lake Mungo included Xantrex 4.5 kVA inverters at a unit cost of $6,300. Significant problems were experienced in adapting the inverter operation for interactive grid support with the final configuration and the units were not considered to be suited to further development due to the lack of a suitable grid interface.
- **High Voltage large scale equipment** – High voltage inverters with grid interactivity are available from established companies such as ABB and Siemens but they are very expensive and not cost effective for low power applications required on weak rural feeders. Previous contact with these companies indicated that development of a suitable unit was not a high priority and any development costs would need to be recovered.
- **Develop a single phase, modular system (preferred option)** – Identify a suitable partner and work with them to develop a specification and produce a prototype, modular power electronics system to provide real and reactive four quadrant operation for voltage support when used in conjunction with a suitable direct current source such as battery storage or renewable generation

(iv) how each demand management project or program was/is to be implemented;

The project is broken into three stages:

- **Knowledge acquisition phase** – Prototype units are developed and installed in an environment where they can be closely monitored and design improvements checked for inclusion in a production version.
- **Field trial phase** - First run production units are installed and their performance evaluated prior to approval for general use.
- **General deployment phase** – Utilisation as a generic supply quality improvement technology on Country Energy's distribution network.

At the close of the 09/10 financial year the project was nearing the end of the knowledge acquisition phase.

(v) the implementation costs of the demand management project or program, and;

The estimated cost for the first stage of the project is $400,000 including product development, test site installation and Country Energy project management costs.

(vi) any identifiable benefits that have arisen from the demand management project or program, including any off peak or peak demand reductions;

Stage 1 of the project involved development and testing of prototype units and this was ongoing through 2009/2010. This was essentially a knowledge acquisition phase to observe the interaction of the prototype units under real network conditions and provide the basis for specification of a production unit.

Benefits will accrue when the technology is deployed as an enabler for peak reduction and reactive power support applications to avoid or defer network augmentation

(c) provide an overview of developments in relation to the demand management projects or programs completed in previous years, and any results to date;

A development agreement was signed with an Australian electronics design and manufacturing company in December 2008 for the production of four prototype units, one for bench testing at their premises and three for a test installation on the Country Energy network. Some of the preliminary development costs were incurred in the 2008/2009 financial year.

During 2009/2010 a test site was established at Queanbeyan, adjacent to the Country Energy Research and Demonstration Centre and an existing solar array and the prototype four quadrant inverters installed in February 2010. There were significant network compatibility issues observed and the units were returned to the supplier for hardware and firmware upgrades to address them.

The units were reinstalled in June 2010 and firmware adjustments continued through to 2nd September 2010 when network stability was achieved and proof of concept demonstrated (see appendix C). A workshop was held with the supplier in late September 2010 and design modifications agreed for a more robust unit suitable for further field evaluation on the Country Energy distribution network.

Field trials of the production units are expected to commence in June 2011.

(d) State whether the costs associated with each demand management project or program identified in the response to paragraph 1.5(a) is:

(i) recoverable under any jurisdictional incentive scheme, and if so, which scheme;
(ii) recoverable under any other Commonwealth or State Government scheme, and if so, which scheme; and
(iii) included in the forecast capex or forecast opex allowances or any other incentive scheme (such as the D-factor scheme for NSW) approved in the AER's 2009-14 distribution determination.

The costs associated with the four quadrant inverter project are not:

(i) recoverable under any other jurisdictional incentive scheme

(ii) recoverable under any other Commonwealth or State Government scheme

(iii) included in the forecast capex or forecast opex allowances or any other incentive scheme (such as the D-factor scheme for NSW) approved in the AER's 2009-14 distribution determination.

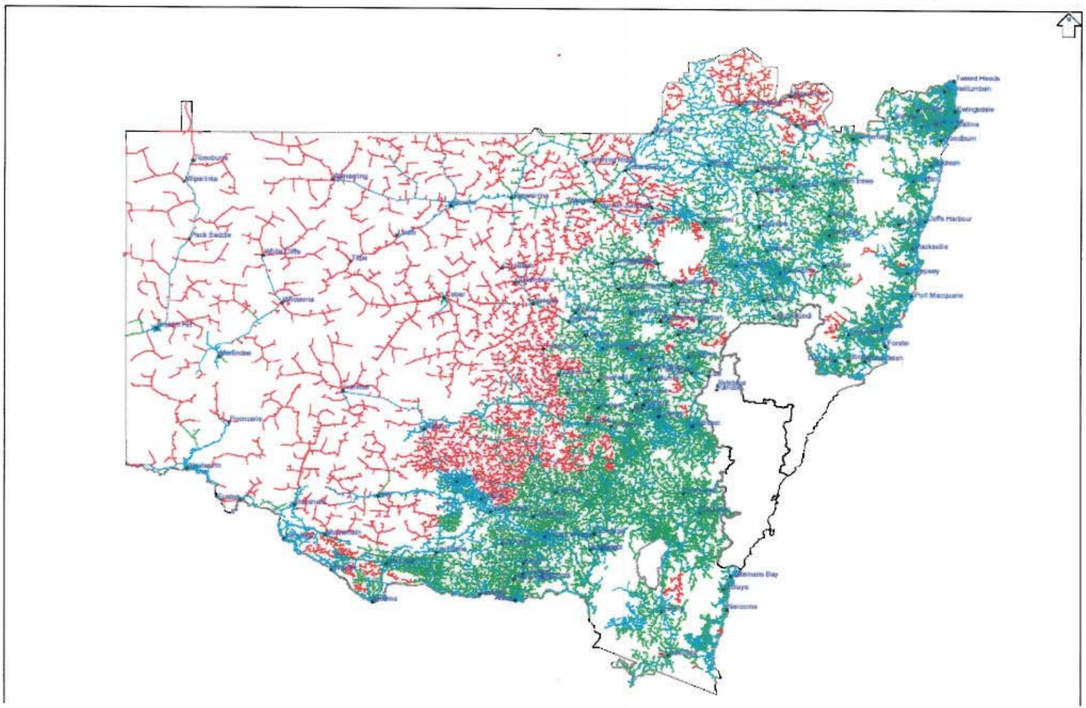
Appendix A

Potential applications for the four quadrant inverter

- Voltage pacification - Providing combinations of real and reactive power to keep voltages within a given range
- Real power support on long rural feeders - On high resistance circuits store energy at light load periods and release it at peak times to reduce voltage drop on the feeder
- Reactive power support - On high reactance circuits use either leading or lagging reactive power to raise or lower voltages as required.
- Generation capacity enhancement - Use lagging reactive power to compensate for voltage rises caused by embedded generation
- Motor starting compensation - The fast (sub-cycle) response and short term rating of the inverter enables it to provide reactive power to balance the fluctuations due to starting of large motors
- Power factor correction - Providing reactive power to correct power factor - minimising line currents and losses
- Load and voltage balancing - Transferring real and reactive power between phases to ensure balanced supply conditions
- Conservation voltage reduction (CVR) - Controlling voltage levels to optimise energy usage and efficiency
- Loss reduction - Managing loading patterns to optimise network current flows for loss minimisation
- Energy storage (community, household, PV) - Balancing load and generation at local level to optimise network utilisation
- Microgrid operation - Operation as a fast response balance between generation and load to stabilise microgrid operation
- Peak price generation - Potential to store energy for release over peak price periods on the energy market to enhance asset value
- Peak lopping - Provide real power at peak periods to ensure network ratings are not exceeded.
- Reliability improvement - Ability to operate in uninterruptible power supply (UPS) mode to improve voltage quality and sustain critical loads during power outages
- Local load control - Potential to act as a signal generator for local control applications
- Harmonic suppression - Acts as a “sink” for lower order harmonics through inductive coupling to the network
- Network monitoring - Current and voltage measurement at the point of application.

Appendix B

Country Energy HV circuits
SWER – red, HV1 – green, HV3 – blue

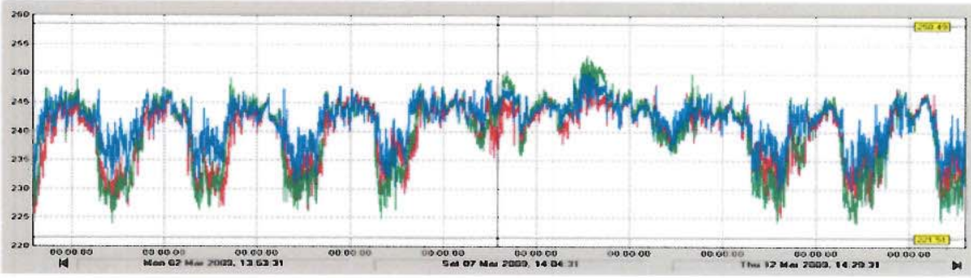


Appendix C

PROOF OF CONCEPT
Influence of four quadrant inverter on voltage levels

WEEKLY VOLTAGE CHART

BEFORE – voltage range 253 to 224, Voltage unbalance 10V



AFTER – voltage range 248V to 234V, unbalance 5V
Normal voltage fluctuations still apparent away from 245V and 239V reactive power support levels