Information Paper for the AER: Services, Classifications and Control Mechanisms

Framework and Approach Process

May 2010

Contents

1. Executive Summary and Overview

This Information Paper has been drafted for the Australian Energy Regulator (AER) in response to an information request sent to Aurora Energy (Aurora) in April 2010. The purpose of this Paper is to provide the AER with information to draw upon when preparing its Framework and Approach Paper.

Specific responses to the AER are set out in Section 3 of this Information Paper. These responses draw upon information set out in the detail of this Paper.

This Paper sets out Aurora's interpretation of the most likely classification of services and price control mechanisms for the next regulatory control period for Aurora's distribution services, on the basis of an arms-length assessment of the characteristics of each of its services against the criteria set out in the National Electricity Rules (Rules).

Aurora considers that the following service classifications for the next regulatory control period are appropriate:

- Network services, comprising services provided over the shared network used to service all network users connected to it, be classified as direct control services and then standard control services, and be regulated under a revenue cap;
- Standard connection services, being those entry and exit services provided on a 'standard' basis, be classified as direct control services and then standard control services and be regulated under a revenue cap. It is proposed that 'above standard' connections such as large customer connections be dealt with as a quoted service;
- Standard metering services, comprising the provision, installation and maintenance of any Type 5, 6 or 7 meter and related meter data capture provided by Aurora, be classified as direct control services and then standard control services and be regulated under a revenue cap;
- Public lighting services, comprising repair, replacement and maintenance of public lighting, alteration and relocation of public lighting and the provision of new public lighting, be classified as direct control services and then alternative control services and be regulated through either a fee based or quoted price cap arrangement;
- Fee based services – previously included in 'special services' and proposed to include replacement and repair of public lighting in the future – be classified as direct control services and then alternative control services and be regulated under a schedule of fees form of price control; and
- Quoted services – previously included in 'special services' and proposed to include replacement and the alteration and relocation of public lighting, the provision of new public lighting and large customer connections – be classified as direct control services and then alternative control services and be regulated under a price cap form of

control. This form of price control would see a fee quoted to the customer once the service has been scoped, not set in advance as for other services. The 'cap' relates to the value of the components in an agreed charging formula approved by the AER.

This is set out in the table below.

Direct Control Service	**Classification**	**Control Mechanism**
Network	Standard control	Revenue Cap
(Standard) connection	Standard control	Revenue Cap
(Standard) metering	Standard control	Revenue Cap
Public lighting		
Repair and replacement of streetlights owned by Aurora	Alternative control – fee based	Price Cap
Repair and replacement of streetlights owned by Third Parties	Alternative control – fee based	Price Cap
Alteration and relocation of streetlights owned by Aurora on request from Third Party	Alternative control - quoted	Price Cap applied to formula components
Alteration and relocation of streetlights owned by Third Parties on request from Third Party	Alternative control - quoted	Price Cap applied to formula components
Provision of new streetlights on request from third party	Alternative control - quoted	Price Cap applied to formula components
Fee based (e.g. disconnections, reconnections, move meter etc)	Alternative control	Price Cap
Quoted (e.g asset relocation at customer request).	Alternative control	Price Cap applied to formula components

2. Introduction

Aurora's distribution services are currently regulated by the Tasmanian Energy Regulator (OTTER) under the Electricity Supply Industry Act 1995 (the Act) and associated Regulations, the Tasmanian Electricity Code (the Code) and the National Electricity Rules (the Rules).

The National Electricity (Economic Regulation of Distribution Services) Amendment Rules 2007 were made under section 90A(1) of the National Electricity Law (The Law) on 16 December 2007. These provided for a new version of Chapter 6 of the Rules. Under the new arrangements, it is expected that the AER will replace OTTER as Aurora's economic regulator and will issue a distribution determination in relation to Aurora's distribution services for the next regulatory control period. This period will commence on 1 July 2012.

Clause 6.8.1 of the Rules requires the AER to prepare a Framework and Approach paper in anticipation of its distribution determination for Aurora's next regulatory control period. Amongst other things, this paper must set out the AER's likely approach to the classification of distribution services and must state the form or forms of control mechanisms that will apply in the next regulatory control period and the reasons for deciding on these control mechanisms.

2.1. Purpose of this Paper

This Information Paper has been drafted for the AER (AER) in response to an information request sent to Aurora in April 2010. The purpose of this Paper is to provide the AER with information to draw upon when preparing its Framework and Approach Paper.

This document:

- Sets out answers to each of the specific questions provided to Aurora by the AER, drawing upon the detail set out in this Paper;
- Sets out a basis for classifying Aurora's distribution services, and for establishing the associated control mechanisms, for the next regulatory control period commencing 1 July 2012 based upon the matters that the AER must have regard for under Chapter 6 of the Rules. Specifically, this Paper assesses Aurora's services and possible control mechanisms against:
    - Clause 6.2.1 of the Rules, which sets out the matters that the AER will have regard to when classifying distribution services as direct control services or negotiated services;
    - Clause 6.2.2 of the Rules, which sets out the matters that the AER will have regard to when classifying direct control services as standard control services or alternative control services;
    - Clause 6.2.5(c), which sets out the matters that the AER must have regard to when deciding on the control mechanism for standard control services;

- Clause 6.2.5(d), which sets out the matters that the AER must have regard to when deciding on the control mechanism for alternative control services; and
- Clause 6.2.6(c), which provides that "the control mechanism for alternative control services may (but need not) utilise elements of Part C (with or without modification)".

2.2. Structure of this Paper

The remainder of this document is structured as follows:

- Section 3 sets out responses to the AER's questions;
- Section 4 examines the service classification and control mechanisms that apply to Aurora in the current regulatory control period;
- Section 5 overviews Aurora's distribution services;
- Section 6 details Aurora's preliminary view of the classification of its distribution services between direct control and negotiated services;
- Section 7 details Aurora's preliminary view of the classification of its direct control services between standard control services and alternative control services;
- Section 8 details Aurora's preliminary view of the control mechanisms that should apply to it's direct control services; and
- Section 9 outlines the resultant classification of services and control mechanism for Aurora's distribution services.

3. Responses to AER Questions

3.1. Please provide a copy of current terms and conditions (including charges), for the services provided by Aurora Energy (including public lighting terms and conditions).

Attachment 1 contains:

- Aurora's 2010/11 Period 4 Pricing Proposal (Pricing Proposal) and Special Services Submission as submitted to OTTER for approval. The Pricing Proposal and Special Services Submission include all currently proposed terms and conditions (including charges) for the regulated services provided by Aurora; and
- Aurora's 2010/11 Public Lighting Proposal (Lighting Proposal) as drafted for internal approval. The Lighting Proposal includes currently proposed terms and conditions (including charges) for the provision of public lighting services.

3.2. The listing of services below has been compiled from OTTER's 2003 declaration decision. Could you confirm whether this is a complete listing of the services currently provided by Aurora Energy? If not, could you please identify those services that are not in this list?

Details of Aurora's services are set out in section 5 of this Paper.

3.3. Please provide information about each service and current control mechanisms

Aurora's current services and control mechanisms are set out in section 4 of this Paper.

3.4. Please indicate if there are: (1) any large, or groups of, customers that have substantial power in negotiating the terms and conditions of supply, including prices; (2) customers that have a credible ability to by-pass or avoid the provision of the service being provided by Aurora Energy.

An assessment of each of Aurora's services against the criteria in clause 6.2.1 of the Rules, which covers the above questions, is set out in section 6 of this Paper.

3.5. OTTER has not previously declared public lighting services. Could you please describe the basis on which Aurora Energy provides public lighting services to councils and the government?

Aurora's current service classifications and control mechanisms are set out in section 4 of this Paper. Details of Aurora's services are set out in section 5 of this Paper.

3.6. Is the charge that Aurora Energy levies for the provision of public lighting services arrived at though commercial negotiation with councils?

No. Details of Aurora's public lighting services are set out in section 5 of this Paper. Aurora's current service classifications and control mechanisms are set out in section 4 of this Paper.

3.7. Does Aurora Energy own all public lighting assets, or do the councils own public lighting assets? If the councils own public lighting assets, are these assets excluded from Aurora Energy's calculation of charges for the provision of public lighting services?

There is a mixture of ownership arrangements for the provision of public lighting services. Where assets are not owned by Aurora, these assets are excluded from Aurora's calculation of charges for the provision of public lighting services.

Details of Aurora's public lighting services are set out in section 5 of this Paper. Aurora's current service classifications and control mechanisms are set out in section 4 of this Paper.

3.8. Could you please detail the methodology used by Aurora Energy to calculate prices for public lighting services?

Aurora's current service classifications and control mechanisms are set out in section 4 of this Paper.

Aurora uses a building block approach in the development of its public lighting services.

It takes the replacement value of each light type (eg 80W Mercury Vapour) and determines an annuity for those assets. This annuity is then added to the estimated operation and maintenance costs for each light type to arrive at a total annual charge. An annual DUoS charge is then applied to each light type based upon its estimated kWh consumption. These two charges are then summed to arrive at a total annual charge that is then converted to a monthly fixed fee.

3.9. Could Aurora Energy please provide details of the trials of LED lighting services?

A small trial involving 3 light fittings is being conducted with the Kingborough Council to establish a benchmark for the potential future deployment of these light fittings within the municipality. This is a joint trial and is being funded by both Aurora and Kingborough Council.

3.10. Why do councils own infrastructure used to provide energy efficient public lighting services?

Councils do not necessarily own infrastructure utilised to provide energy efficient public lighting services. Councils may own poles but in all cases Aurora will own the light fittings for public lighting services.

3.11. The AER understands that Aurora-Pay-As-You-Go (APAYG) metering services are excluded from OTTER's determination. Please indicate how these services are provided? Are they provided by Tasmanian retailers or by Aurora Energy?

Aurora's current service classifications and control mechanisms are set out in section 4 of this Paper. Details of Aurora's services are set out in section 5 of this Paper. In relation to specific information sought by the AER:

- Aurora has approximately 40,000 APAYG customers. Less than 500 of these customers have standard meters;
- These APAYG customers have a meter that is provided by the Retailer (Aurora Retail). The few customers (< 500) that have the standard meter have the Aurora Network (distributor) electronic meter installed and a Payguard unit provided by Aurora Retail to handle the APAYG functionality; and
- Standard accumulation meters with an add-on will be the standard arrangement for all new APAYG customers and prevents meter churn when customers switch from APAYG to standard retail tariff offerings.

3.12. Does Aurora Energy own any dual function assets?

No. Aurora does not own any dual function assets.

3.13. Can Aurora clarify whether the reliability of supply (SAIDI, SAIFI and MAIFI3) data is collected in accordance with the AER's definitions of these parameters in the STPIS?

Aurora does not collect reliability of supply data in accordance with the definitions provided within the AER's definitions of those parameters in the STPIS. It is also important to note that Aurora does not have information on actual customer numbers connected to the distribution network and instead uses connected kVA as a proxy for customer numbers. The methodology prescribed by OTTER also requires a kVA weighting when establishing reliability outcomes for the communities described in the Code.

3.14. Can Aurora clarify whether the reliability of supply data is collected at the feeder level and can be broken down into the feeder classifications in the AER's STPIS

Aurora does not collect reliability data at feeder level. Aurora collects data in accordance with the 101 communities under the methodology that is defined in the Code (attached to this Paper)[1]

[1] Tasmanian Electricity Code, Schedule 8.1

3.15. Can Aurora Energy clarify whether the reliability of supply data is collected on a daily basis and can be used to calculate the major event day threshold outlined in appendix D of the AER's STPIS?

Reliability data is collected on a daily basis and it is possible that the calculations required to establish major event day thresholds could be undertaken although further work is required to confirm this.

3.16. Can Aurora Energy clarify whether it collects customer service data in accordance with the STPIS definitions of call centre performance, streetlight repair, new connections and response to written enquiries?

Aurora collects customer service data for call centre performance, streetlight repair and new connections. Aurora does not collect data on responses to written enquiries in a manner that would support the current STPIS but further work is required to confirm this. A copy of Aurora's latest Quarterly Service Performance Report is attached to this Paper for the AER's information.

3.17. If Aurora Energy collects reliability of supply and Customer service performance data that differs from that in the AER's STPIS, can Aurora outline the customer service data that Aurora collects and provide definitions of these parameters.

This information is set out in Schedule 8.1 of the Code.

3.18. Can Aurora specify whether the current guaranteed service level scheme applied under OTTER's previous price determination will continue beyond the 2007-2012 regulatory control period?

The regime for GSLs in Tasmania is implemented by the OTTER Guideline *Guaranteed Service Level (GSL) Scheme,* Version 2, issued in December 2007. Aurora is obliged to comply with Guideline as a consequence of its distribution licence issued by OTTER under the Electricity Supply Industry Act 1995. Unless positive action is taken otherwise, this will continue beyond the current regulatory control period.

3.19. Can Aurora outline the GSL parameters under the AER's STPIS that it monitors and is able to apply?

Customers in Tasmania qualify for a GSL payment if the following services are provided by Aurora at a standard below that which is deemed acceptable: frequency of interruptions, duration of interruptions, new connections, streetlight repairs, and prior notice of planned interruptions.

4. Current Service Classification and Control Mechanisms

4.1. Classification of Services

In accordance with the Price Control Regulations[2], OTTER determined that the following services would be 'declared' services for the purpose of determining maximum prices that would apply to Aurora from 1 January 2008[3]:

- Distribution network services, being the conveyance of electricity (from the connection point with the transmission system to the customer connection point including entry services, use of system services and exit services, excluding any connection assets owned and maintained by the customer) including:
  - the undertaking of works or the provision of maintenance or repairs for the purposes of carrying out conveyance of electricity; and
  - the provision, installation and maintenance or repairs of any switchgear or other electrical plant essential to the transportation and delivery of electricity;
- Special Services, being services provided for the benefit of a single customer rather than uniformly supplied to all network customers. Special Services include but are not limited to connections, disconnections (including disconnections made at the request of the retailer) and reconnections; and
- Metering services, being the provision, installation and maintenance of any Type 5, 6 or 7 meter and related meter data capture provided by Aurora, excluding the provision of integrated prepayment meters and the provision of metering to a standard in excess of that required for the billing of customer services, but including special meter readings and meter testing of Type 5, 6 or 7 meters.

Under the Price Control Regulations OTTER is required to conduct a price investigation and set maximum prices for each of the declared services.

4.2. Current Control Mechanisms

The control mechanism applied to each of the declared services for the current regulatory control period is discussed below.

[2] Electricity Industry Supply (Price Control) Regulations 2003

[3] Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, Final Report and Proposed Maximum Prices September 2007, page 5.

Distribution Network Services

For the current regulatory control period OTTER determined[4] to regulate maximum prices for distribution network services by a revenue cap, calculated using a building block approach. The Maximum Allowable Revenue (MAR) was set equal to the commercial return on the efficient investment made in the assets used by the business plus allowances for depreciation and efficient operating and maintenance costs, plus certain pass-through costs.

OTTER concluded that while there were efficiency gains theoretically achievable in using either a revenue yield or a tariff basket approach in place of a revenue cap, "…the benefits did not outweigh the risks to customers due to load volatility and uncertainties of load forecasting."[5]

Special Services

OTTER identified the following Special Service categories (based on those proposed by Aurora):

- Customer Energisation and Billing – requiring connection site visit:
  - Energisation, de-energisation or re-energisation of a connection customer or to perform check reads – 'no appointment', ie at an unspecified time;
  - Same day energisation, de-energisation, re-energisation;
  - Energisation where an inspection is required prior to energisation;
  - Energisation, de-energisation or re-energisation of a connection at an arranged time; and
  - Rectification of illegal connection;
- Meter Alterations:
  - Tariff alteration (add or modify), single phase metering circuit;
  - Tariff alteration (add or modify), a three phase metering circuit;
  - Reconnect a previously disconnected meter;
  - Adjustment of time clock; and
  - Install or remove metering.
- Meter Testing:
  - Testing of a single phase meter at a customer's request;
  - Testing of a three phase meter at a customer's request;
  - Testing of a current transformer meter at a customer's request; and
- Wasted visit (i.e. unable to complete job due to issues at customer installation).

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[4] 2007 Investigation of Prices for Electricity Distribution Services on Mainland Tasmania Decision and Statement of Reasons - Form of Regulation

[5] Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, Final Report and Proposed Maximum Prices, September 2007, page 27.

OTTER applied a price cap mechanism to these services indicating that a price cap was appropriate since the costs of providing these services are primarily volume driven. In addition, the costs of providing these services were excluded from the calculation of the maximum revenues for distribution network services and maximum prices for metering services.[6]

OTTER accepted the initial prices for these services (representing an average fee) as proposed by Aurora and determined[7] that:

- average price increases each year must be calculated by reference to a 'basket of services and to be no more than the increase in the Weighted Average Wage Index for the Electricity Gas and Water Supply Industry in the preceding calendar year;
- Aurora must, as part of its annual Pricing Proposal, submit for approval a list of all the Special Services and their proposed prices for the following 12 months to OTTER each year as part of the tariff setting process; and
- Aurora must publish its fees and charges for all Special Services and the charge out rates used in pricing of all non-standard services.

Metering Services

OTTER set an allowance for the provision, installation and maintenance of any Type 5, 6 or 7 meters and related meter data capture based on an annuity approach.

The annuity was calculated based on replacement cost, to which the operating costs (predominantly the cost of meter reading) were added. OTTER adopted the annuity approach on the basis that it was felt that it would be impractical to assess the age of the meter stock, and on an assumption that an annuity approach would give an equivalent annual charge to that expected over the long-term from a building block approach using depreciated optimised replacement cost.

OTTER determined to express the maximum allowable revenue for the provision of metering services (as declared) as an average daily allowance per meter for each major customer class. This was calculated from forecast costs and forecast numbers of meters in each class.[8]

Public Lighting Services

For the current regulatory control period OTTER determined[9] not to regulate public lighting services.

6 Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, Supplementary Final Report and Statement of Reasons on Maximum Prices for Special Services Provided by Aurora Energy, June 2008 page VII.

7 Ibid page VIII.

8 Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, Final Report and Proposed Maximum Prices September 2007, page 268

9 2007 Investigation of Prices for Electricity Distribution Services on Mainland Tasmania Decision and Statement of Reasons - Form of Regulation

5. Services Provided by Aurora

This section describes the range of distribution services and unregulated activities that Aurora provides to retailers, developers and end use customers.

5.1. Distribution Services

Clause 6.2.1(a) of the Rules requires that distribution services to be regulated be classified as either direct control services or negotiated distribution services and clause 6.2.1(b) of the Rules allows a DNSP's services to be grouped together for the purposes of this classification.

Aurora intends to adopt the following groupings for its distribution services:

- network services;
- connection services;
- metering services;
- public lighting services;
- fee based services; and
- quoted services.

These groups of services are described below.

5.1.1. Network Services

Network services are delivered through the provision and operation of apparatus, equipment, plant and/or buildings (excluding connection assets) used to convey, and control the conveyance of, electricity to customers.

In the case of Aurora, such assets include poles, lines, cables, substations, communication and control systems, and involve activities such as inspection, testing, repairs, maintenance, vegetation clearing and asset replacement, asset refurbishment and asset construction services that are not connection services. Network services also include the provision of operational staff and management, emergency response and administrative support for other network services.

Network services are characteristically provided on a 'standard' basis, with the 'above standard' supply of these services generally dealt with as a fee based or quoted service. An above standard network supply refers to the provision of a higher standard of reliability or quality of supply, which would be provided by Aurora by providing assets which enable greater reliability or quality of supply at a customer's premises.

5.1.2. (Standard) connection services

Chapter 10 of the Rules defines connection services as consisting of entry services and exit services. An entry service is a service provided to serve a generator or group of generators, or a network service provider or group of network service providers, at a single connection point. An exit service is a service provided to serve a distribution customer or a group of distribution customers, or a network service provider or group of network service providers, at a single connection point.

Standard connection services include connection, augmentation and energisation provided on a 'standard' basis. 'Above standard' connections should be dealt with as alternative control services (either fee based or quoted service).

Connection services are incorporated in Aurora's 'Distribution Network Service' category for the purposes of the current regulatory period. Where a connection is not viable, due to the cost of the connection and the expected revenue from standard tariffs, a contribution is charged.

5.1.3. (Standard) Metering services

This category relates to the provision, installation and maintenance of any Type 5, 6 or 7 meter and related meter data capture provided by Aurora, excluding the provision of integrated prepayment meters, and the provision of metering to a standard in excess of that required for the billing of customer services. Aurora is the:

- Metering Provider for all Type 5 to 7 metering installations; and
- Metering Data Provider for all Type 5 to 7 metering installations.

5.1.4. Public Lighting Services

Public lighting services in Tasmania have never been regulated and are not currently regulated.

The AER previously concluded that the provision, construction and maintenance of public lighting assets is a distribution service and therefore subject to regulation under the Rules.[10] Aurora considers that public lighting is, on its reading of the Rules, a distribution service in Tasmania.

Aurora has the following categories of public lighting services[11]:

- repair, replacement and maintenance of public lighting owned by Aurora, where the streetlight services are provided to third parties;
- repair, replacement and maintenance of public lighting owned by third parties where Aurora undertakes the service for a fee;
- alteration and relocation of existing public lighting assets owned by Aurora at the request of a third party;

[10] AER Final Decision, Framework and approach paper Classification of services and control mechanisms, Energex and Ergon Energy 2010–15, August 2008, page 23.

[11] Where a public lighting asset is not owned by Aurora these services are not part of the distribution system and are unregulated.

- alteration and relocation of existing public lighting assets owned by a third party at the request of that third party; and
- provision of new public lighting by Aurora to customers or third parties on the request of that customer or third party.

These categories are consistent with those recently reviewed by the AER in developing the Victorian Framework and Approach.[12]

Aurora's responsibilities in relation to each of these categories in the current regulatory control period are addressed below.

Aurora is responsible for the repair, replacement and maintenance of public lighting by virtue of the Code. Specifically, Section 8.2.3 requires that:

> A *Distribution Network Service Provider* must repair or replace an item of *public lighting* within 7 *business days* of being notified by any person that such repair or replacement is necessary, unless the *public lighting* provider has contractual or other arrangements with another party.

In general, Aurora does not perform alterations or relocations of existing public lighting assets. Similarly, in general, Aurora does not provide new public lighting. However, to the extent that these services are provided, these have been incorporated in the service classification assessment.

Public lighting assets are connected to Aurora's distribution system. The conveyance of electricity to public lighting assets is therefore not considered to be a public lighting service, but rather is a network service.

5.1.5. Fee Based Services

Aurora provides a range of services on a fixed fee basis to retailers and customers. These services are generally homogenous in nature and scope (e.g one disconnection or reconnection will be similar in scale and scope to another disconnection or reconnection) and therefore their costs can be estimated in advance for the purposes of setting a price with reasonable certainty. This means that a fixed fee can be set in advance for the provision of these services.

Aurora's fee based distribution services for 2010-11 include:

- De-energisation;
- Transfer of supply;
- Re-energisation;
- Same day re-energisation;
- Check reads;
- Sub-tenant read;
- Meter alteration;

[12] Framework and approach paper Citipower, Powercor, Jemena, SP AusNet and United Energy Regulatory control period commencing 1 January 2011.

- Add circuit (meter);
- Alter circuit (meter);
- Meter test - Single phase meter;
- Meter test - Three phase meter;
- Current transformer meter;
- Remove meters - at a customer's request or building demolition during normal business hours;
- Remove meters and service connection - at a customer's request or building demolition during normal business hours;
- Remove CT connected meters - at a customer's request or building demolition during normal business hours;
- Renewable energy connection - supply and install single phase dual register basic import/export metering equipment at a customer's premise during normal business hours;
- Temporary single phase builder's supply underground - temporary position to be removed when permanent supply connected;
- Temporary three phase builder's supply underground - temporary position to be removed when permanent supply connected;
- Temporary single phase builder's supply underground - permanent position;
- Temporary three phase builder's supply underground - permanent position;
- Temporary single phase builder's supply overhead - temporary position to be removed when permanent;
- Temporary three phase builder's supply overhead - temporary position to be removed when permanent;
- Temporary single phase builder's supply overhead - permanent position;
- Temporary three phase builder's supply overhead - permanent position;
- Temporary supply for show or carnival – underground;
- Temporary supply for show or carnival – where consumer's mains are to be attached to an existing Aurora pole;
- Temporary supply for show or carnival – where an overhead service is required;
- Disconnect Service Connection – for fascia change or alteration during normal business hours;
- Tee-up normal hours – requested by contractor whilst undertaking work at customer's installation during normal business hours;

- Tee-up after hours – requested by contractor whilst undertaking work at customer’s installation after normal business hours;
- Tee-up- wasted visit – requested by contractor whilst undertaking work at customer’s installation where service connections crew are not required once on site; and
- Open turret or cabinet for electrical contractor installing or altering customer’s mains during normal business hours.

All of these services are classified as special services in the current regulatory control period.

The fixed fees for these services for the current regulatory control period are approved annually by OTTER as part of Aurora’s annual Pricing Proposal.

5.1.6. Quoted Services

Aurora provides a range of services on a quoted fee basis to retailers and customers. The nature and scope of these services are specific to individual retailers or customer’s needs, and therefore the cost of providing the services cannot be estimated without first understanding the retailer’s or customer’s requirements. This means Aurora must set individual prices for these services after they have been requested. It would not be appropriate to set a generic fixed total fee in advance for the provision of these types of services.

Examples of these quoted services include, but are not limited to:

- Removal or relocation of Aurora’s assets at a customer’s (for example, the Tasmanian Government’s) request;
- Above-standard services which are provided:
- At a higher standard than the standard service, due to a customer’s request for Aurora to do so; or
- Through a non-standard process at a customer’s or retailer’s request (for example, where more frequent meter reading is required).

These services are currently classified as special services in the current regulatory control period.

OTTER’s Final Decision set out an annual pricing process in regard to Special Services including a requirement for Special Services and their proposed prices for the following 12 months to be submitted to the Regulator each year as part of the tariff setting process. OTTER noted the existence of non-standard services and indicated that that in some circumstances the specification of a fixed price was not always feasible and therefore required Aurora to publish its charge out rates used to calculate the requisite charge for all non-standard services.[13]

[13] Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, Supplementary Final Report and Statement of Reasons on Maximum Prices for Special Services, Provided by Aurora Energy June 2008, page 20.

5.2. Unregulated Activities

Aurora provides a range of services that are not distribution services within the meaning of the Rules and are therefore not regulated by OTTER and will not be regulated by the AER. This is because they are not provided by means of, or in connection with, the distribution system. Examples of these services, some of which have historically been associated with distribution services, include:

- Provision of high load escorts;
- Metering Data Agent services for Type 1 to 4 metering installations;
- Erection of extra poles on customers' premises, which are not connection services; and
- Location of underground cables.

It is proposed that these services not be classified by the AER.

5.3. Summary of Proposed Groupings

The following service groupings are proposed for the next regulatory control period:

- network services;
- (standard) connection services;
- (standard) metering services;
- public lighting services;
- fee based services; and
- quoted services.

These services classifications are consistent with those recently adopted by the AER in relation to the upcoming Victorian electricity distribution regulatory reset.

6. Proposed Classification between Direct Control and Negotiated Services

This section classifies Aurora's six distribution services described in section 5 against the criteria in clause 6.2.1(c) of the Rules.

6.1. Requirements of the Rules

Clause 6.2.1(a) of the Rules requires that distribution services be classified as either direct control services or negotiated distribution services and clause 6.2.1(b) of the Rules allows a DNSP's services to be grouped together for the purposes of this classification.

Clause 6.2.1(c) of the Rules sets out the matters that the AER must have regard for when assessing a DNSP's classification of services between direct control services or negotiated distribution services:

The AER must, in classifying a distribution service, have regard to:

- the form of regulation factors; and
- the form of regulation (if any) previously applicable to the relevant service or services and, in particular, any previous classification under the present system of classification or under the previous regulatory system (as the case requires); and
- the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction); and
- any other relevant factor.

The form of regulation factors referred to in 6.2.1(c)(1) of the Rules are set out in section 2F of the Law. These factors are:

- the presence and extent of any barriers to entry in a market for electricity network services;
- the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider;
- the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market;
- the extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user;
- the presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service;

- the presence and extent of any substitute for, and the elasticity of demand in a market for, electricity or gas (as the case may be);
- the extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider.

Clauses 6.2.1(d) and (e) of the Rules state that:

> *In classifying distribution services that have previously been subject to regulation under the present or earlier legislation, the AER must act on the basis that, unless a different classification is clearly more appropriate:*
>
> - *there should be no departure from a previous classification (if the services have been previously classified); and*
> - *if there has been no previous classification – the classification should be consistent with the previously applicable regulatory approach.*
>
> *If the Rules, however, require that a particular classification be assigned to a distribution service of a specified kind, a distribution service of the relevant kind is to be classified in accordance with that requirement.*

6.2. Interpreting the Form of Regulation Factors

Neither the Law nor the Rules provide any guidance as to the way in which the form of regulation factors should be applied when classifying distribution services between direct control services and negotiated services. In particular, it is not clearly stated that the presence of market power in the provision of a service means that the service should be classified as a direct control service as opposed to a negotiated service. Rather:

- The Rules simply require the AER to "have regard to" the form of regulation factors in classifying services; and
- The form of regulation factors list a series of market characteristics but do not explicitly say that the presence of particular market characteristics means that a service should be classified as either a direct control service or a negotiated service.

Further, neither the Law nor the Rules provide any guidance as to the way in which the form of regulation factors should be weighted in relation to:

- Each other; and
- The other classification criteria in clause 6.2(c)(2) to (4) of the Rules, which the AER must consider in making its classification decision.

Given this, the following analysis has had regard for the AER's Victorian Framework and Approach Paper and the proposals from Energex and Ergon Energy to the AER relating to the classification of services and control mechanisms to apply for their next regulatory control period (1 July 2010 to 30 June 2015).

These documents contain interpretations of the form of regulation factors, which were drawn from the Expert Panel on Energy Access Pricing's (Expert Panel) April 2006 "Report to the Ministerial Council on Energy", which set out the economic rationale for the form of regulation factors that were subsequently reflected into the Law. These interpretations are duplicated and expanded upon below.

The presence and extent of any barriers to entry in a market for electricity network services – section 2F(a) of the Law.

This clause is interpreted to mean that a network service should be subject to a direct control form of regulation, and should therefore be classified as a direct control service, if Aurora:

- Has a natural monopoly in the supply of that service;
- Has substantial market power in the supply of that service;
- Has a monopoly based in legislation so that no other party can be authorised to provide the service; and
- There are other significant legislative barriers that prevent other parties from providing the service.

The presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider – section 2F(b) of the Law.

The presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market – section 2F(c) of the Law.

These clauses are interpreted to mean that a network service should be subject to a direct control form of regulation, and should therefore be classified as direct control services, if:

- The network services that Aurora offers through its shared network give it the ability to exploit operational and economic efficiencies in the provision of other distribution services and thereby limit competition in the market for these other distribution services;
- The non-network distribution services that Aurora offers give it the ability to exploit operational and economic efficiencies in the provision of distribution services and thereby limit competition in the market for these distribution services; and
- It is difficult to quantify the incremental and stand alone costs and benefits for users of providing the services.

The extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user – section 2F(d) of the Law.

This clause is interpreted to mean that a network service should be subject to a direct control form of regulation, and should therefore be classified as a direct control service, if:

- There are no large or concentrated groups of customers that have substantial power in negotiating the terms and conditions of supply, including prices, with Aurora in relation to a service;
- Customers generally do not have a credible ability to by-pass or avoid the provision of the service being provided by Aurora. This means that customers cannot fulfil their needs in any other way than acquiring the service from Aurora; and
- The characteristics of the assets that are used to supply the service, and the customer base, are such that there is a low potential for full or partial asset stranding from reduced demand for that service.

The presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service – section 2F(e) of the Law.

The presence and extent of any substitute for, and the elasticity of demand in a market for, electricity or gas (as the case may be) – section 2F(f) of the Law.

These clauses are interpreted to mean that a network service should be subject to a direct control form of regulation, and should therefore be classified as a direct control service, if:

- Customers' demand for the service is relatively price inelastic (i.e. demand does not fall significantly as the price increases);
- There is limited scope for demand side management as a means of reducing the customer's total cost of acquiring the service;
- The service being acquired is not a product of choice for the customer – i.e if it is an essential service; and
- Customers do not have options for sourcing the service from a supplier other than Aurora.

The extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider – section 2F(g) of the Law.

This clause is interpreted to mean that a network service should be subject to a direct control form of regulation, and should therefore be classified as a direct control service, if Aurora's knowledge of its costs, services, infrastructure and market creates a substantial negotiating power imbalance in dealing with customers.

6.3. Application of clause 6.2.1(c) criteria

Section 17 Part 3 of the Act indicates that a person must not carry on operations in the electricity supply industry for which a licence is required (including the distribution of electricity) unless the person holds a licence under the Act authorising the relevant operations.

Aurora is currently the only business in Tasmania to hold a distribution licence. As a consequence, Aurora is the only business permitted to provide distribution services in Tasmania.

In addition to licensing requirements, Section 109(1) of the Act prevents any unauthorised persons from interfering with Aurora's electricity infrastructure or electrical installations. In particular, Section 109(1)(b) states that "A person must not, without proper authority connect, disconnect or interfere with a supply of electricity from a transmission system or distribution network."

6.3.1. Network Services

Aurora's legislated monopoly to undertake 'network services' is derived from:

- Section 17 of the Act, which requires that a person must not carry on operations in the electricity supply industry including in relation to distributing electricity unless the person holds a licence;
- Clause 1.1 of Aurora's electricity distribution licence, which grants Aurora a licence to distribute electricity over the authorised distribution network set out in Schedule 1 – Part 1 of its licence; and
- Section 109(1) of the Act prevents any unauthorised persons from interfering with Aurora's electricity infrastructure or electrical installations.

Because it is the only entity empowered to distribute electricity over the authorised distribution network and the only party authorised to perform work on the network, only Aurora can provide network services in relation to the network area.

Accordingly, in reference to the form of regulation factors, network services should be classified as direct control services because:

- There are very high barriers to entry for any other party providing network services to users on Aurora's network. The licensing requirements mean that Aurora is the only party that can provide network services using Aurora's assets within the distribution area. In addition, general applications of property rights, as well as the Act, would stop any other party providing services using Aurora's network without its approval;
- It is very difficult to isolate the incremental or stand alone costs for individual users of network services, because these services are provided by a shared network with indivisible usage; and
- While there are large customers using the network, these customers have limited ability to exert substantial market power in negotiation of network services because:
  - no single customer contributes a significant proportion of the costs of the shared network in revenue; and
  - the possibilities for a customer to by-pass the network or seek substitutes for the supply of electricity are limited.

The proposal to classify network services as direct control services is consistent with:

- OTTER's current regulation of these services, as distribution network services by way of a revenue cap; and
- The classification of this type of service in other jurisdictions.

6.3.2. (Standard) Connection Services

Connection services relate to building connection assets at the customer's premises as well as connecting those connection assets to the distribution network.

Aurora's legislated monopoly to undertake 'standard connection services' is derived from:

- Section 17 of the Act, which requires that a person must not carry on operations in the electricity supply industry including in relation to distributing electricity unless the person holds a licence;
- Clause 1.1 of Aurora's electricity distribution licence, which grants Aurora a licence to distribute electricity over the authorised distribution network set out in Schedule 1 – Part 1 of its licence; and
- Section 109(1) of the Act prevents any unauthorised persons from interfering with Aurora's electricity infrastructure or electrical installations. In addition, Aurora is the only party authorised to energise connections.[14]

Standard connection services are currently provided within the broader offering by Aurora of 'network services'.

[14] Section 20 of the *Occupational Licensing (Electrical Work) Regulations 2008* places restriction on the parties able to energise electrical works.

In reference to the form of regulation factors, standard connection services should be classified as direct control services based on the existence of:

- High barriers to a new entrant competing with Aurora to provide connection services to customers from Aurora's network. This is because there is a legislative prohibition on unauthorised persons interfering with Aurora's network;
- Network externalities given that Aurora can use factors of production that relate to its shared network to provide connection services. Specifically, Aurora can use the same assets, labour and materials to provide connection and network services; and
- No real opportunities for customers to exert counter-veiling market power in relation to connection services given that:
  - Customers do not always initiate the service – connection services can be initiated by a retailer, a DNSP or a customer; and
  - These services are high volume, individually relatively low cost to provide and are generally not requested more than one service at a time nor can requests readily be aggregated.

This means that, in a practical sense, Aurora does not negotiate with customers and retailers in the provision of these services, and no real competitive or substitution possibilities for connection services given that a licence is required to operate a distribution network.

It is not considered that there are significant asymmetries between Aurora's knowledge of its costs, services, infrastructure and market and that of its customers given that there is extensive information available in the market about the costs of new connections. However, this is not considered to outweigh the above assessment against the other form of regulation factors.

The proposal to classify standard connection services as direct control services is consistent with:

- OTTER's current treatment of Aurora's connection services as regulated services; and
- The classification of connection services in the other NEM jurisdictions where these service are treated as regulated services, other than in NSW.

6.3.3. (Standard) Metering Services

This category relates to the provision, installation and maintenance of any Type 5, 6 or 7 meter and related meter data capture provided by Aurora, excluding the provision of integrated prepayment meters, the provision of metering to a standard in excess of that required for the billing of customer services, and excluding special meter readings and meter testing (on customer request) of Type 5, 6 or 7 meters.

These services are regulated by OTTER in the current regulatory control period.

Aurora's legislated monopoly to undertake 'standard metering services' is derived from:

- Aurora's position as the:
  - Metering Provider for all Type 5 to 7 metering installations; and
  - Metering Data Provider for all Type 5 to 7 metering installations.15
- Section 109(1) of the Act which prevents any unauthorised persons from interfering with Aurora's electricity infrastructure or electrical installations. Because metering services relate to the customer's meter, no third party can provide them without Aurora's approval.

In reference to the form of regulation factors, metering services should be classified as direct control services based on existence of:

- High barriers to a new entrant competing with Aurora to provide ancillary metering services within its existing supply area given the existing position of Aurora as the Metering Provider and Metering Data Provider and the Act;
- Network externalities given that Aurora can use factors of production that relate to its shared network to provide metering services. Specifically, Aurora can use the same assets, labour and materials to provide metering services and network services;
- No material opportunities for customers to exert counter-veiling market power in relation to ancillary metering services given that:
  - Customers do not always initiate the service – different metering services can be initiated by a retailer, a DNSP or a customer; and
  - These services are sought infrequently by customers, are individually relatively low cost to provide and customers do not generally purchase more than one service at a time or aggregate their purchases with other customers.

This means that, in a practical sense, Aurora does not negotiate with customers or retailers in the provision of these services. It also means that there is no real competitive or substitution possibilities for metering services given that Aurora has a regulated monopoly to provide these services.

There are also significant asymmetries between Aurora's knowledge of its costs, services, infrastructure and market in the supply of metering services and that of its customers. This is because Aurora is the monopoly supplier and customers tend to seek these services relatively infrequently.

The proposal to classify metering services as direct control services is consistent with:

- OTTER's current treatment of Aurora's metering services as regulated services. These services are classified as metering services and are subject to a revenue cap control mechanism; and

[15] Aurora is the Metering Provider and Metering Data Provider by virtue of being the only party currently performing these services in Tasmania.

- Other NEM jurisdictions where standard metering services are treated as regulated services.

6.3.4. Public Lighting

The categories of public lighting services are:

- repair, replacement and maintenance of public lighting owned by Aurora, where the streetlight services are provided to third parties;
- repair, replacement and maintenance of public lighting owned by third parties where Aurora undertakes the service for a fee;
- alteration and relocation of existing public lighting assets owned by Aurora at the request of a third party;
- alteration and relocation of existing public lighting assets owned by a third party at the request of that third party; and
- provision of new public lighting by Aurora to customers or third parties on the request of that customer or third party.

While Aurora does not have a legislated monopoly to undertake the repair, replacement and maintenance of public lighting in general, it is obliged under Section 8.2.3 of the Code to repair or replace an item of public lighting within 7 business days of being notified by any person that such repair or replacement is necessary, unless the public lighting provider has contractual or other arrangements with another party.

In addition, to the extent that Aurora owns the public lighting asset, Section 109(1) of the Act prevents any unauthorised persons from interfering with Aurora's electricity infrastructure or electrical installations. This means that all of those services that are provided on Aurora's assets can only be provided by Aurora.

In reference to the form of regulation factors, all of the public lighting services should be classified as direct control services based on the existence of:

- High barriers to entry in relation to the repair, replacement and maintenance of public lighting and the alteration and relocation of existing public lighting assets. This is because these assets are owned by Aurora and there is a legislative prohibition on unauthorised persons interfering with Aurora's network;
- High barriers to entry for services provided on third party assets by virtue of externalities from Aurora's provision of other services. Aurora can use factors of production that relate to its shared network to provide public lighting services. In particular, Aurora can use the same assets, labour and materials to provide public lighting services on its own public lighting assets as for those owned by third parties; and
- No real competitive or substitution possibilities for these public lighting services given that the market for the provision of public lighting services in Tasmania is underdeveloped.

While classifying all of these public lighting services as direct control services is not consistent with the current treatment of these services by OTTER, the definition of these services as distribution services under the Rules means that these services are likely subject to regulation by the AER.

The classification of all of these public lighting services as direct control services is consistent with the AER's classification of these services in Queensland[16] and the AER's classification of repair, replacement and maintenance of public lighting and the alteration and relocation of existing public lighting assets in Victoria[17].

6.3.5. Fee Based Services

Aurora's legislated monopoly to undertake 'fee based services' is derived from:

- Section 17 of the Act, which requires that a person must not carry on operations in the electricity supply industry including in relation to distributing electricity unless the person holds a licence;
- Clause 1.1 of Aurora's electricity distribution licence, which grants Aurora a licence to distribute electricity over the authorised distribution network set out in Schedule 1 – Part 1 of its licence; and
- Section 109(1) of the Act which prevents any unauthorised persons from interfering with Aurora's electricity infrastructure or electrical installations.

Because it is the only entity empowered to distribute electricity over the authorised distribution network and the only party authorised to perform work on the network, only Aurora can provide fee based services in relation to its assets within its network area.

In reference to the form of regulation factors, fee based services should be classified as direct control services based on the existence of:

- High barriers to a new entrant competing with Aurora to provide fee based services on Aurora's assets within its existing supply area given the licensing requirements and the existing provisions of the Act;
- Network externalities given that Aurora can use factors of production that relate to its shared network to provide fee based services on its own assets. Specifically, Aurora can use the same assets, labour and materials to provide fee based services and network services;
- No real opportunities for customers to exert counter-veiling market power because, even though customers can define the nature of the service that is required, the service will still be delivered by Aurora using its assets and will be in relation to its distribution network. This means that only Aurora can provide these services and therefore, in a practical

[16] AER Final Decision, Framework and approach paper Classification of services and control mechanisms, Energex and Ergon Energy 2010–15, August 2008, page 23.

[17] AER Framework and approach paper Citipower, Powercor, Jemena, SP AusNet and United Energy Regulatory control period commencing 1 January 2011.page 46

sense, it does not negotiate with customers in the provision of fee based services; and

- No real competitive or substitution possibilities for fee based services given that it is an offence for any other party than Aurora to interfere with Aurora's distribution network.

There are also significant asymmetries between Aurora's knowledge of its costs, services, infrastructure and market in the supply of quoted services and that of its customers. This is because Aurora is the monopoly supplier and customers tend to seek these services relatively infrequently.

The proposal to classify fee based services as direct control services is consistent with:

- OTTER's current treatment of Aurora's fee based services as regulated services. These services are classified as special services; and
- Other NEM jurisdictions where fee based services are treated as regulated services.

6.3.6. Quoted Services

Quoted services are services for which Aurora must make an assessment of the works required before the service can be delivered in order to determine the cost associated with its delivery, and therefore the price that is to be charged. They are works that are related to Aurora's assets.

As per fee based services above, Aurora has a monopoly obligation to provide quoted services because they relate to works on Aurora's assets. This is because Section 109(1) of the Act prevents any unauthorised persons from interfering with Aurora's electricity infrastructure or electrical installations.

In reference to the form of regulation factors, quoted services should be classified as direct control services based on the existence of:

- High barriers to a new entrant competing with Aurora to provide quoted services on its assets within its existing supply area the licensing requirements and the existing provisions of the Act;
- Network externalities given that Aurora can use factors of production that relate to its shared network to provide quoted services. Specifically, Aurora can use the same assets, labour and materials to provide quoted services and network services;
- No real opportunities for customers to exert counter-veiling market power because, even though customers can define the nature of the service that is required, the service will still be delivered by Aurora using its assets and will be in relation to its distribution network. This means that only Aurora can provide these services and therefore, in a practical sense, it does not negotiate with customers in the provision of quoted services; and
- No real competitive or substitution possibilities for quoted services given that it is an offence for any other party than Aurora to interfere with Aurora's distribution network.

There are significant asymmetries between Aurora's knowledge of its costs, services, infrastructure and market in the supply of quoted services and that of its customers. This is because Aurora is the monopoly supplier and customers tend to seek these services relatively infrequently.

The proposal to classify quoted services as direct control services is consistent with:

- OTTER's current treatment of Aurora's quoted services as regulated services. These services are classified as special services; and
- Other NEM jurisdictions where quoted services are treated as regulated services.

There are no other relevant factors that need to be considered in classifying quoted services under clause 6.2.1(c) of the Rules.

6.3.7. Conclusion

On the basis of the above assessment against the criteria in clause 6.2.1(c) of the Rules, all six of Aurora's distribution services set out in section 5.1 should be classified as direct control services. None of Aurora's distribution services should be classified as negotiated distribution services.

7. Proposed Classification between Standard Control and Alternative Control Services

This section classifies Aurora's direct control services described in section 5, and analysed in section 6, as either standard control services or alternative control services on the basis of the criteria in clause 6.2.2(c) of the Rules.

7.1. Interpreting the criteria in Clause 6.2.2(c)

As noted in section 6.2 of this paper, guidance has been taken in relation to the interpretation of the criteria in clause 6.2.2(c) of the Rules from the AER's Victorian Framework and Approach Paper and the proposals from Energex and Ergon Energy to the AER relating to the classification of services and control mechanisms to apply for their next regulatory control period.

The following sets out an interpretation as to when a service should be classified as a standard control service or an alternative control service based on the criteria in clause 6.2.2(c) of the Rules, and draws heavily from the AER's Victorian Framework and Approach Paper.

The potential for development of competition in the relevant market and how the classification might influence that potential – clause 6.2.2(c)(1) of the Rules

This is interpreted to mean that a direct control service should be classified as a standard control service if:

- There is no potential for the development of competition in the market for that service or, even if a competitor was to enter, Aurora would retain a very dominant position in the market; or
- The classification of the service as a standard control service could result in Aurora offering the service on a basis that could prevent a potential competitor entering the market for that service.

The possible effects of the classification on administrative costs of the AER, the Distribution Network Service Provider and users or potential users – clause 6.2.2(c)(2) of the Rules

This is interpreted to mean that a direct control service should be classified as a standard control service if the administrative costs of being classified as an alternative control service outweigh the benefits, having regard for the assessment against the other criteria in clause 6.2.2(c) of the Rules.

The regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made – clause 6.2.2(c)(3) of the Rules

This is interpreted to mean that a direct control service should be classified as a standard control service if the service was previously classified as a prescribed network service, the basis of that classification was consistent with the criteria in clause 6.2.2(c) of the Rules, and if the market for that service has not materially changed.

The desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction) – clause 6.2.2(c)(4) of the Rules

This is interpreted to mean that a direct control service should be classified as a standard control service if the service is currently classified as a prescribed network services in Tasmania or if a similar services is classified as a prescribed distribution service in other jurisdictions.

The extent the costs of providing the relevant service are directly attributable to the customer to whom the service is provided – clause 6.2.2(c)(5) of the Rules

This is interpreted to mean that a direct control service should be classified as an alternative control service if, other things being equal, the costs of providing that service can be attributed to a particular user.

7.2. Application of clause 6.2.2(c) criteria

7.2.1. Network Services

Aurora has a legislative monopoly to provide network services by virtue of the licensing requirements and the restrictions on unauthorised persons interfering with Aurora's electricity infrastructure or electrical installations set out in Section 109(1) of the Act.

Aurora considers that these services should be classified as standard control services because:

- There is neither actual, nor potential for the development of, competition for the supply of network services on Aurora's network. There is a legislative restriction on third parties interfering with Aurora's network;
- This is consistent with OTTER's current treatment of Aurora's network services, and with the classification of these services in NEM jurisdictions;
- The costs of providing network services are not directly attributable to individual customers, and involve allocations of shared and overhead costs; and
- None of the other classification criteria are relevant for the purposes of this assessment.

7.2.2. (Standard) Connection services

Aurora has legislative obligations to provide standard connection services using its assets, and therefore these services should be standard control services. The reasons for this are that:

- There is neither actual, nor potential for the development of, competition for the supply of connection services on Aurora's network. There is a legislative restriction on third parties interfering with Aurora's network;

- Classifying connection services as standard control services will involve no significant change in administrative costs for Aurora and the AER. Further, these costs would not outweigh the benefits of the protection that standard control services provide to customers by virtue of the application of Part C of the Rules;
- This is consistent with OTTER's current treatment of Aurora's connection services, and with the classification of these services in NEM jurisdictions. While connection services are excluded services in NSW[18] and Victoria[19], this is not considered relevant to this classification.[20] This is because there are no legislative prohibitions on third parties undertaking these services in these jurisdictions and indeed there are transparent regimes in place to facilitate contestability of connection works; and
- While the costs of connection works could be assigned to customers, this is not considered for equity with past connections to be an appropriate way of dealing with connection costs. This factor is considered to be outweighed by the remaining factors.

7.2.3. (Standard) Metering services

As noted in section 6.3.3, Aurora has legislative obligations to provide standard metering services, and therefore these services should be standard control services. The reasons for this are that:

- These services relate to works on Aurora's assets and Section 109(1) of the Act prohibits unauthorised persons from interfering with Aurora's electricity infrastructure or electrical installations; and
- Aurora is the Metering Provider and Metering Data Provider for Types 5 to 7 metering installations.

Metering services should be classified as standard control services because:

- There is neither competition nor the potential for the development of competition for these services. The Act and the Rules would need to be amended in order for any other party than Aurora to provide these services in relation to Aurora's assets;
- The classification of Aurora's standard metering services as a standard control service would not impede a new entrant from providing these services in competition with Aurora. This is because without legislative amendments, no other person can provide metering services on Aurora's network;
- Classifying standard metering services as standard control services will involve no significant change in administrative costs for Aurora and the AER. The treatment is consistent with OTTER's current treatment of Aurora's standard metering services as regulated distribution services;

[18] IPART, NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Report, page 23

[19] ESCV, October 2005 Final Decision Electricity Distribution Price Review 2006-10 Final Decision Volume 1 Statement of Purpose and Reasons

[20] Excluded services have been mapped as alternative control under the transitional provisions for the ACT and as unregulated (or potentially alternative control) under the transitional provisions for NSW.

- A review of the interstate treatment of metering services indicates that standard metering services are classified in a similar way in other jurisdictions; and
- Although the costs of providing metering services are in the main directly attributable to customers, and involve limited allocations of shared and overhead costs, this is not considered to outweigh the assessment against the other criteria. This is especially the case given that Aurora is the only party that can currently provide these services and that changes would need to be made to legislation and the Rules in order to enable competition.

7.2.4. Public Lighting

Section 5.1.4 identified the following categories of public lighting services:

- repair, replacement and maintenance of public lighting owned by Aurora, where the streetlight services are provided to third parties;
- repair, replacement and maintenance of public lighting owned by third parties where Aurora undertakes the service for a fee;
- alteration and relocation of existing public lighting assets owned by Aurora at the request of a third party;
- alteration and relocation of existing public lighting assets owned by a third party at the request of that third party; and
- provision of new public lighting by Aurora to customers or third parties on the request of that customer or third party.

Section 5.1.4 noted that, in general, Aurora was not involved with the alteration and relocation of existing public lighting assets or the provision of new public lighting.

As noted in section 6.3.4 of this paper, where Aurora owns the public lighting assets, Aurora has a monopoly on the repair, replacement and maintenance of public lighting and the alteration and relocation of these assets by virtue of Section 109(1) of the Act. Where Aurora does not own the public lighting assets, there are externalities in the provision of these services by virtue of Aurora's provision of network services and public lighting services on its own public lighting assets.

Similarly, given the underdeveloped market for the provision of these public lighting services and the existence of these externalities, Aurora has substantial market power in the provision of new public lighting assets.

These services should be classified as alternative control services because:

- The classification of these services as alternative control services would not, of itself, impede a new entrant from providing these services in competition with Aurora in the future. This could be facilitated via legislative amendment;
- Classifying public lighting services as alternative control services would involve a change in administrative costs for Aurora and the AER since

these services are currently unregulated. However, given the new requirement for these services to be regulated such a comparison is not valid;

- This proposed classification would be in line with the way in which these services are classified in NEM jurisdictions; and
- The costs of providing the service can be directly attributed to individual customers.

Repair, replacement and maintenance of public lighting should be subject to fee based regulation. This reflects the fact that it is possible to forecast costs associated with repair, replacement and maintenance on the basis of past expenditure and forecast inspection cycles. As such, it is possible to develop an annual fee associated with the provision of the service.

In the case of the alteration and relocation of existing public lighting assets and the provision of new public lighting, it is proposed that these services be provided on a quoted basis. This reflects the fact that the costs associated with these services are impossible to estimate in advance.

7.2.5. Fee Based Services

Aurora provides a range of services on a fixed fee basis to retailers and customers. These services are generally homogenous in nature and scope and therefore a fixed fee can be set in advance for the provision of these services.

Aurora has a legislated monopoly to undertake fee based services on the assets that it owns on it's network. This is because Aurora is the only entity empowered to distribute electricity over the authorised distribution network and the only party authorised to perform work on the network.

These services should be classified as alternative control services because:

- These services are currently classified as special services with OTTER approving prices on an annual basis. This would suggest that classifying these services as alternative control services would be consistent with the previous regulatory treatment;
- The classification of these services as alternative control services would not, of itself, impede a new entrant from providing these services in competition with Aurora in the future. This could be facilitated via legislative amendment;
- Classifying fee based services as anything other than alternative control services would involve a change in administrative costs for Aurora as it would alter the way in which these services are currently provided. It is unlikely that the benefits of doing this would exceed the costs;
- This proposed classification would be in line with the way in which these services are classified in NEM jurisdictions; and
- The nature of fee based services is that they do not involve building new assets and the costs of providing the service can be directly attributed to individual customers.

7.2.6. Quoted Services

Quoted services are services for which Aurora must make an assessment of the works required before the service can be delivered in order to determine the quality desired by the customer, the cost associated with its delivery, and therefore the price that is to be charged.

As per fee based services above, Aurora has a monopoly obligation to provide quoted services because they relate to works on Aurora's assets. This is because Section 109(1) of the Act prevents any unauthorised persons from interfering with Aurora's electricity infrastructure or electrical installations.

These services should be classified as alternative control services because:

- These services are currently classified as special services. This would suggest classifying these services as alternative control services in line with the AER's Framework and Approach documents in Victoria and Queensland;
- The classification of these services as alternative control services would not, of itself, impede a new entrant from providing these services in competition with Aurora in the future;
- There would be no material effect on administration costs of the AER, Aurora or any other party. This is because classifying quoted services as alternative control services is consistent with the current regulatory approach;
- This proposed classification would be in line with the way in which these services are classified in NEM jurisdictions; and
- The nature of quoted services is that they can be directly attributed to individual customers.

7.2.7. Conclusion

The likely classification of Aurora's direct control services is summarised in Table 1.

Table 1: Proposed classification of direct control services

Direct Control Service	Classification
Network	Standard control
(Standard) connection	Standard control
(Standard) metering	Standard control
Public lighting	
Repair and replacement of streetlights owned by Aurora	Alternative control – fee based
Repair and replacement of streetlights owned by Third Parties	Alternative control – fee based
Alteration and relocation of streetlights owned by Aurora on request from Third Party	Alternative control - quoted
Alteration and relocation of streetlights owned by Third Parties on request from Third Party	Alternative control - quoted
Fee based	Alternative control
Quoted	Alternative control

8. Proposed Control Mechanisms

This section sets out the proposed control mechanisms to apply to Aurora's standard control services and alternative control services.

8.1. Requirements of the Rules

There are six control mechanisms that can be applied to direct control services. Clause 6.2.5(b) of the Rules states that the control mechanism for direct control services may consist of:

- A schedule of fixed prices;
- Caps on the prices of individual services;
- Caps on the revenue to be derived from a particular combination of services;
- Tariff basket price control;
- Revenue yield control; or
- A combination of any of the above.

The forms of control mechanism available for standard and alternative control services are the same.

The Rules provide that, in deciding on a control mechanism for standard control services, the AER must have regard to the following requirements of clause 6.2.5(c) of the Rules:

- the need for efficient tariff structures; and
- the possible effects of the control mechanism on administrative costs of the AER, the Distribution Network Service Provider and users or potential users; and
- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination; and
- the desirability for consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and
- Any other relevant factor.

In deciding on a control mechanism for alternative control services, the AER must have regard to the following requirements of clause 6.2.5(d) of the Rules:

- the potential for development of competition in the relevant market and how the control mechanism might influence that potential; and
- the possible effects of the control mechanism on administrative costs of the AER, the Distribution Network Service Provider and users or potential users; and

- the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination; and
- the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and
- any other relevant factor.

Clause 6.2.6 of the Rules goes on to state that:

- For standard control services, the control mechanism must be of the prospective CPI-X form, or some incentive-based variant of the prospective CPI-X form, in accordance with Part C.
- For alternative control services, the control mechanism must have a basis stated in the distribution determination.
- The control mechanism for alternative control services may (but need not) utilise elements of Part C (with or without modification).

8.2. Interpreting clause 6.2.5

The Rules do not apply any ranking to the possible control mechanisms and therefore the control mechanisms will be decided on the basis of appropriate regard for the matters detailed in clause 6.2.5(c) and 6.2.5(d).

8.2.1. Interpreting clause 6.2.5(c) criteria

The need for efficient tariff structures – clause 6.2.5(c)(1) of the Rules

This is interpreted to mean that a proposed control mechanism is acceptable if it would not result in inefficient tariff structures.

The possible effects of the control mechanism on administrative costs of the AER, the Distribution Network Service Provider and users or potential users – clause 6.2.5(c)(2) of the Rules

This is interpreted to mean that a proposed control mechanism is acceptable if its administrative costs would not outweigh the benefits, having regard for the assessment against the other criteria in clause 6.2.5(c) of the Rules.

The regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination – clause 6.2.5(c)(3) of the Rules

This is interpreted to mean that, other things being equal, the AER will be predisposed to retaining the current revenue cap that applies to network and metering services for standard control services in the next regulatory control period unless there is a compelling reason to change control mechanisms.

The desirability for consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction) – clause 6.2.5(c)(4) of the Rules

This is interpreted to mean that, other things being equal, the AER will be predisposed to aligning the control mechanisms that apply to Aurora with that applied to equivalent services for other DNSPs in the NEM.

Any other relevant factor – clause 6.2.5(c)(5) of the Rules

There are no other relevant factors that need to be taken into account by the AER in determining the control mechanisms that are to apply to standard control services.

8.2.2. Interpreting clause 6.2.5(d) criteria

The potential for development of competition in the relevant market and how the control mechanism might influence that potential – clause 6.2.5(d)(1) of the Rules

This is interpreted to mean that a proposed control mechanism is acceptable if it would either:

- Assist to develop competition in the relevant market; or
- Not detract from other factors that may assist to develop competition in the relevant market.

The possible effects of the control mechanism on administrative costs of the AER, the Distribution Network Service Provider and users or potential users – clause 6.2.5(d)(2) of the Rules

This is interpreted to mean that a proposed control mechanism is acceptable if its administrative costs would not outweigh the benefits having regard for the assessment against the other criteria in clause 6.2.5(d) of the Rules.

The regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination – clause 6.2.5(d)(3) of the Rules

Alternative control services do not exist in the current regulatory control period. Therefore, this is interpreted to mean that, other things being equal, the AER will be predisposed to retaining the current control mechanisms that apply to Aurora's distribution services, being a revenue cap for network, standard connection and standard metering services and a price cap for special distribution services.

The desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction) – clause 6.2.5(d)(4) of the Rules

Alternative control services are offered by DNSPs in SA, NSW[21], Queensland[22] and Victoria[23]. This clause is interpreted to mean that, other things being equal, the AER will be predisposed to aligning the control mechanisms that apply to Aurora's distribution services with those applied to equivalent services for other DNSPs in the NEM.

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21 AER Draft Decision, New South Wales Draft Distribution Determination 2009–10 to 2013–14, 21 November 2008

22 AER Final Decision, Framework and approach paper Classification of services and control mechanisms, Energex and Ergon Energy 2010–15, August 2008

23 AER Framework and Approach Paper Citipower, Powercor, Jemena, SP AusNet and United Energy Regulatory Control Period Commencing 1 January 2011.

Any other relevant factor – clause 6.2.5(d)(5) of the Rules

It is not proposed that there be any other relevant factors taken into account by the AER in determining the control mechanisms that are to apply to Aurora's services.

The following sections set out the proposed control mechanisms for Aurora's direct control services and why these are appropriate given the matters that the AER must have regard to, under clause 6.2.5(c) and 6.2.5(d) of the Rules.

8.3. Proposed Control Mechanisms for Direct Control Services

It is proposed that a Revenue Cap control mechanisms be applied to Aurora's standard control services.

The following provides an explanation of the revenue cap control mechanism and a justification of its application to standard control services in the context of the criteria set out in clause 6.2.5(c) of the Rules.

8.3.1. Justification of Revenue Cap for Standard Control Services

Standard control services cover Aurora's network services, standard connection services and standard metering services.

Under the current regulatory approach, these services are subject to a revenue cap control mechanism. The revenue cap currently applicable to network services and standard connection services is the typical building block revenue cap, while the revenue cap in relation to metering services is currently derived on an annuity basis with the maximum allowable revenue for the provision of these services expressed as an average daily allowance per meter for each major customer class. The separate revenue cap for metering services would no longer operate under this proposed classification.

A revenue cap is an appropriate control mechanism for all of Aurora's standard control services. Under a revenue cap, the AER would specify a cap on Aurora's allowed revenue for each year of the regulatory control period.

The revenue that Aurora would receive under this form of price control is the actual tariff (and components of tariffs) escalated by the CPI-X mechanism, multiplied by the actual volume for that year. Revenue derived under this form of price control is capped at the maximum allowable revenue.

The basic form of the revenue control is:

$$\sum_{i=1}^{n}\sum_{j=1}^{m} p_{ij}^{t+1} * q_{ij}^{t+1} \le MAR^{t+1}$$

Where:

"MAR" is the value of the revenue constraint (maximum allowable revenue);

"p" are prices (dollars and cents);

"q" are quantities (e.g. kWh delivered);

"t" is the current year of the regulatory period;

"i" denotes each tariff classification (e.g. residential) of a total "n" classifications; and

"j" denotes tariff components (e.g. fixed monthly charge) of a total "m" components.

A revenue cap is an appropriate control mechanism for Aurora's standard control services on the basis of clause 6.2.5(c) of the Rules because it:

- Is one of the control mechanisms that is allowed under clause 6.2.5(b)(3) of the Rules;
- Is the same mechanism as currently imposed on Aurora – albeit with the application of a separate revenue cap for standard metering services;
- Would not result in inefficient tariff structures. This is because Aurora would have flexibility to determine individual tariffs in order to recover the revenue cap, subject to any specific side-constraints that may be imposed by the AER, including determining the split between fixed and variable tariffs. New tariffs can readily be introduced throughout the regulatory control period as required;
- Is consistent with the current control mechanism that is applied to these services, which is a fixed revenue cap. While this proposed classification removes the separate metering revenue cap which currently operates in Tasmania, the calculation of two control mechanisms for one class of services is not considered to be efficient or appropriate; and
- Is consistent with the control mechanism that has been used for standard control services in Queensland and the ACT, although it is inconsistent with that used in Victoria, NSW and South Australia.

When considered on an overall basis, it is proposed that a revenue cap control mechanism is appropriate for application to standard control services in the next regulatory control period.

8.4. Proposed control mechanisms for alternative control services

Section 7 of this paper identified the following alternative control services:

- Fee based services, including the repair, replacement and maintenance of public lighting assets; and
- Quoted services, including 'above standard' customer connections and, if provided by Aurora, the provision of new public lighting and the alteration and relocation of public lighting.

The majority of these services are currently classified as special services and regulated by OTTER under a price cap control mechanism. As noted previously, streetlighting services are currently unregulated.

It is appropriate that the control mechanism for fee based and quoted services be a price cap, to be applied using caps on:

- Unit costs for the quoted service grouping of alternative control services; and
- Individual prices for all other alternative control services.

A formula, and a fixed price quotation, is an appropriate control mechanism and form of price control because it:

- Is one of the control mechanisms that is allowed under clause 6.2.5(b)(3) of the Rules;
- Would not result in inefficient tariff structures. This is because Aurora would have flexibility to determine individual quotations in order to recover the costs of undertaking works requested by customers;
- Will not have any material impact on the competition for an alternative control service or impede the potential to develop competition for these services;
- Will not impose additional administrative costs on users, Aurora or the AER since the proposed control mechanism is the same as that which currently applies;
- Is consistent with the way in which these services are provided in NEM jurisdictions, where utilities wait until the service has been scoped and then provide a quotation for the service; and
- Is the only way that the regulatory regime can cope with services where a price simply cannot be provided before the service has been scoped.

9. Conclusion

Table 2 summarises the proposed classification of services and control mechanism for Aurora's distribution services on the basis of the outcomes detailed in sections 6 to 8 of this document.

Table 2: proposed classification of services and control mechanism for Aurora's distribution services

Service Title	Classification	Control Mechanism
Network Services	Standard Control Services	Revenue Cap
Standard Connection Services	Standard Control Services	Revenue Cap
Standard Metering Services	Standard Control Services	Revenue Cap
Public lighting		
Repair and replacement of streetlights owned by Aurora	Alternative control – fee based	Price Cap
Repair and replacement of streetlights owned by Third Parties	Alternative control – fee based	Price Cap on components of formula
Alteration and relocation of streetlights owned by Aurora on request from Third Party	Alternative control - quoted	Price Cap on components of formula
Alteration and relocation of streetlights owned by Third Parties on request from Third Party	Alternative control - quoted	Price Cap on components of formula
Fee based (e.g. disconnections, reconnections, move meter etc)	Alternative control	Price Cap
Quoted (e.g asset relocation at customer request).	Alternative control	Price Cap on components of formula

9.1. Mapping Existing (OTTER) Regime to the new (AER) Regime

A summary of the mapping of existing services to the proposed new arrangements in the Rules is provided in Table 3.

Table 3: Mapping of existing services to the proposed new arrangements.

Existing Form of Price Control	Existing Services (OTTER)	New Services (AER)	Proposed Control Mechanism
Revenue Cap	Distribution Network Services	Standard Control Services – Network Services (utilising the shared network)	Revenue Cap
		Standard Control Services – Standard Connection Services	Revenue Cap
	Metering Services	Standard Control Services – Standard Metering Services	Revenue Cap
Schedule of Fees (for standard 'homogeneous' services) and Charge out rates (for non-standard 'quoted' services)	Special Services	Alternative Control Services – Fee based and quoted services, including large customer connections (quoted), repair, replacement and maintenance of public lighting (fee based), alteration and relocation of existing public lighting assets (quoted) and provision of new public lighting (quoted) and other non-standard services (quoted).	Price Cap
N/A	Unregulated Activities	Alternative Control Services - Public Lighting Services - repair, replacement and maintenance of public lighting (fee based), alteration and relocation of existing public lighting assets (quoted) and provision of new public lighting (quoted)	Price cap
		Unregulated Activities	N/A

10. Aurora 2010/11 Pricing Proposal

Network Pricing Proposal

Period 4
1 July 2010 to 30 June 2011

Version 1.3 – May 2010

Contents

Document History

Date	Version	Comments
23 April 2010	1.0	Original
30 April 2010	1.1	Approved for submission
30 April 2010	1.2	Submitted to OTTER
7 May 2010	1.3	Resubmission to reflect corrections recommended by OTTER

1. Introduction

1.1. Purpose

This Pricing Proposal has been prepared to fulfil the dual roles of compliance with the Guideline and to provide customers connected to the Aurora Distribution Network with an indication of the proposed tariffs for their use of the network during the fourth period governed by the Determination, which is to run from 1 July 2010, until 30 June 2011.

1.2. Regulatory Arrangements

Aurora is a Tasmanian Government owned electricity distribution and retail company. It was formed in July 1998 pursuant to the *Electricity Companies Act 1997* and incorporated under the Corporations Law. It has two shareholders, the Minister for Energy and the Treasurer.

As the monopoly provider of distribution and certain metering services within the Tasmanian jurisdiction, Aurora is required to hold a distribution licence in accordance with the ESI Act. This licence was issued in December 1998, and authorises Aurora to distribute electricity on mainland Tasmania subject to certain conditions and regulatory controls.

The Office of the Tasmanian Economic Regulator undertakes the regulation of distribution services within the Tasmanian jurisdiction. A key component of this jurisdictional regulation is the review and monitoring of the economic framework that will apply to the regulated businesses within the jurisdiction.

Under this economic framework the Regulator is required to investigate the prices for the provision of distribution and metering services in accordance with the Price Control Regulations. This investigation culminates in the release of a pricing determination that outlines the maximum allowable revenues, or prices, that Aurora may earn for the provision of regulated distribution and metering services for the regulatory period.

The 2007 Determination was delivered in October, 2007, and sets the maximum allowable revenues and prices that Aurora may earn for the regulatory period from 1 January 2008 to 30 June 2012.

Tariffs for collection of revenues allowed by the Determination are constructed in compliance with the Determination and the Network Tariff Guideline.

1.3. Current Network Tariffs

The Network Tariffs offered in Period 4, which runs from 1 July 2010 until 30 June 2011 are presented in Table 1

Table 1: Network Tariffs Offered in Period 4

Tariff	MSATS Code	Description	NUoS Components
N01	AURESGEN	General Network – Residential	Daily charge with declining three step energy charge
N02	AUBLVGEN	General Network – Business	Daily charge with declining two step energy charge
N02a	AUBLVNURSE	General Network – Business, Nursing Homes	Daily charge with declining two step energy charge - Obsolete
N02b	AUBLVCURT	General Network – Business, Curtilage	Daily charge with declining two step energy charge - Obsolete
N03	AUBLVDMKW	LV kW Demand	Daily charge, single energy charge and declining two step demand charge - Obsolete
N05	AUHEATUNCO	Uncontrolled Energy	Daily charge with single energy charge
N06	AUHEATCONT	Controlled Energy	Daily charge with single energy charge
N06a	AUHEATCONN	Controlled Energy	Daily charge with single energy charge
N07	AUUMS	Small LV Unmetered	Daily charge with single energy charge
N08	AUIRRIG	LV Day/Night (Irrigation)	Daily charge with peak and off-peak energy charge - Obsolete
N08a	AUIRRIGTOU	LV Irrigation (TOU)	Daily charge with time of use energy charge
N09	AUBLVDMKVA	LV kVA Demand	Daily charge, single energy charge and declining two step demand charge
N10	AUBHVDMKVA	HV kVA Demand	Daily charge, single energy charge and single demand charge - Obsolete
N10s	AUHVSPECDM	HV KVA Specified Demand	Daily charge, time of use energy charge, specified and excess demand charges
N11	AUBHVDMKW	HV kW Demand	Daily charge, single energy charge and single demand charge - Obsolete
N13	AUPAYG	LV PAYG	Daily charge with single energy charge - obsolete
N13b	AUBUSTOU	LV ToU – Business	Daily charge with time of use energy charge
N13r	AURESTOU	LV ToU - Residential	Daily charge with time of use energy charge

Tariff	MSATS Code	Description	NUoS Components
N15	AUCHVDM2	HV kVA Specified Demand (> 2.0MVA)	Daily charge, time of use energy charge, specified and excess demand charges and nodal transmission charge
N20	AUUMSSL	Street Lighting	Single demand charge
ITC	AUSPCCUST	Individual Network Tariff Calculation	Charges individually calculated for each customer

1.4. Proposed Network Tariff Rates for Period 4

The following table summarises the proposed Network Tariff rates for Period 4.

Table 2: Network Tariff Rates for Period 4

Network Tariff	Tariff Description	Daily Charge c/day	Metering Charge c/day (if applicable)	ToU Energy Rates c/kWh			Step Energy Rates c/kWh			Step Demand Rates c/kVA (kW)/day		Capacity Charges c/kVA/day	
				Peak	Shoulder	Off-Peak	Step 1	Step 2	Remaining	Step 1	Remaining	Specified	Excess
N01	General Network - Residential	36.567	7.993				11.870	10.980	10.683				
N02	General Network - Business	36.567	11.545				12.592		10.683				
N02a	General Network - Nursing	36.567	11.545				11.273		5.947				
N02b	General Network - Curtilage	7.313	11.545				12.592		10.683				
N03	LV kW Demand	196.300	14.687						2.728	57.272	51.622		
N05	Uncontrolled Energy	3.657	7.933						3.650				
N06	Controlled Energy	7.180	8.133						0.990				

Network Tariff	Tariff Description	Daily Charge c/day	Metering Charge c/day (if applicable)	ToU Energy Rates c/kWh			Step Energy Rates c/kWh			Step Demand Rates c/kVA (kW)/day		Capacity Charges c/kVA/day	
				Peak	Shoulder	Off-Peak	Step 1	Step 2	Remaining	Step 1	Remaining	Specified	Excess
N06a	Controlled Energy	7.180	8.133						0.941				
N07	Small LV Unmetered	27.425							13.851				
N08	LV Irrigation (Day/Night)	175.721	14.349	12.592		0.990							
N08a	LV Irrigation (ToU)	158.830	14.688	12.592	7.941	0.965							
N09	LV kVA Demand	178.455	14.687						2.480	44.256	39.890		
N10	HV kVA Demand	122.244	63.800						1.439		24.023		
N10s	HV kVA Specified Demand	122.244		1.295	1.033	0.641						18.017	180.172
N11	HV kW Demand	134.468	63.800						1.582		31.089		
N13	LV PAYG	36.567							6.760				
N13b	LV ToU - Business	36.567	14.688	11.286	7.167	0.990							

Network Tariff	Tariff Description	Daily Charge c/day	Metering Charge c/day (if applicable)	ToU Energy Rates c/kWh			Step Energy Rates c/kWh			Step Demand Rates c/kVA (kW)/day		Capacity Charges c/kVA/day	
				Peak	Shoulder	Off-Peak	Step 1	Step 2	Remaining	Step 1	Remaining	Specified	Excess
N13r	LV ToU - Residential	36.567	9.816	11.286	7.167	0.990							
N15	HV In Excess of 2MVa	16.550		1.295	0.351	0.045						8.527	42.635

2. Proposed Changes for Period 4

This section is to address Guideline 2.3(d)(9):

> "A Network Tariff Pricing Proposal must…describe the nature and extent of and proposed changes from the previous period and demonstrate that the changes comply with these Guideline and the 2007 Determination…"

The following sections detail the changes that Aurora proposes to make to its suite of Network Tariffs for Period 4.

Aurora interprets the requirement to "demonstrate that the changes comply with these Guideline" to mean that details of the tariffs should be presented as outlined in Section 3 of this Pricing Proposal. Aurora submits that this is the case, with the tariffs presented in Section 3.

Aurora interprets the requirement to "demonstrate that the changes comply with…the 2007 Determination" to mean that Aurora must demonstrate that the new tariffs have been developed such that they comply with the Pricing Principles set out in the 2007 Determination. These principles, the meaning of compliance with them, and the methodologies applied to ascertain compliance, have been addressed in the NTS (Section 9). Their application to the changes to the proposed tariff suite is presented below.

Aurora has also consulted on the introduction of new tariffs and changes to existing tariffs via the previous release of two papers:

- Introduction of Time of Use and Specified Demand Network Tariff Charging Components Issues Paper (the Issues Paper); and
- Proposed Implementation Timetable for Time of Use Tariffs Position Paper (the Position Paper).

2.1. Proposed Changes for Period 4

Aurora proposes to make no changes to its suite of Network Tariffs for Period 4.

2.2. Compliance with the Pricing Principles

2.2.1. Postage Stamp Pricing

Network Tariff Pricing Principle (a) of Schedule 2 of the Determination requires that:

> Network tariffs for small customers belonging to a particular class are to be uniform, regardless of where in mainland Tasmania the customer is supplied with electricity.

The Network Tariffs for all LV tariffs have been set to be uniform across the state. The only Network Tariffs that are not uniform are those for the largest HV customers or customers with specific connection characteristics that require an individual tariff calculation.

As an example the tariffs for Nursing Homes (N02a), Curtilage (N02b) and Aurora Pay As You Go (N13) are uniform across the state.

2.2.2. Bounded Revenues

Network Tariff Pricing Principle (b) of Schedule 2 of the Determination requires that:

> For each Network Tariff class, the revenue expected to be recovered should lie on or between:
>
> an upper bound representing the stand alone cost of serving the customers who belong to that class; and
>
> a lower bound representing the avoidable cost of not serving those customers.

The meaning and methodology associated with this Principle is discussed in detail in Section 9.2 of the NTS. As an example the upper and lower bounds and the revenues recovered through the N02a and N02b tariffs are presented in Table 3. Inspection will show that the revenues expected to be recovered through the proposed tariffs lie between the prescribed upper and lower bounds.

Table 3: Assessment of Stand-Alone and Avoidable Costs against Forecast Tariff Revenue for Period 4

Tariff Class	Stand-Alone Cost ($ million)	Expected Revenue ($ million)	Avoidable Cost ($ million)
N02b - General Network - Business less curtilage	260.53	3.71	0.00
N02a - General Network - Business Nursing Homes	260.53	2.73	0.00

A full listing of the bounded revenues can be found in Section 6.4.2

2.3. Charging Parameter Qualities

2.3.1. Tariffs and LRMC

Clause 2(c)(1) of Schedule 2 of the 2007 Determination requires that:

> A Network Tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class must…take into account the long run marginal cost for the service, or in the case of a charging parameter, for the element of the service to which the charging parameter relates…

This clause is discussed in detail in Section 9.3.1 of the NTS. In line with that discussion, Aurora has structured the charging parameters to signal the impact that customers will have on the network, manage demand and volume variance risk, and avoid sending signals that could result in inefficient choices being made by customers of that tariff class. In this context:

- Aurora's fixed charge parameters for each tariff have been designed to recover the incremental costs that arise from the connection and management of the customer. This sends a signal to customers about the cost of their connection works and sets a constant and foreseeable price for those customers that assist them in making a decision to connect with full visibility of the costs. The fixed charges also provide Aurora with a fixed revenue source by which it can recover its costs and therefore ensure that upstream investment decisions can be made with clarity;
- Aurora Energy's volume charges are designed to recover the costs of the shared network on a basis which reflects the characteristics of the network user.

2.3.2. Transaction Costs, Fixed/Variable Charges, NEM Costs and Signals

Clause 2(c)(2) requires that

> …a Network Tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class must be determined having regard to:
>
> Transaction costs associated with the tariff or each charging parameter;
>
> The observed proportion of fixed and variable charges applied in other NEM jurisdictions for similar services; and
>
> The appropriate allocation of costs associated with Aurora's participation in the NEM and retail contestability between contestable and non-contestable customers; and
>
> Whether customers of the relevant tariff class are able or likely to respond to price signals.

These requirements are discussed in detail in Section 9.3.2 of the NTS. Based on those discussions, Aurora wishes to make the following observations.

Aurora believes that it has met the transaction costs aspect of this principle because:

- The number and structure of its Network Tariffs have been established with reference to the transaction costs associated with that number and structure of tariffs. All of Aurora Energy's tariffs use standard usage and demand parameters which are readily measurable and provided by means of Aurora's existing metering and information systems; and
- The decision to introduce new Network Tariffs has been undertaken with reference to the transaction costs of abolishing or introducing these tariffs.

- Bearing in mind the comments on this issue in Section 9.3.2 of the NTS, it is not possible to compare the proportions of fixed and variable costs for these tariffs with analogous tariffs in mainland jurisdictions because there are no analogous tariffs in mainland jurisdictions. Moreover, the discounted fixed costs for the curtilage tariff N02b distorts the proportions.
- Aurora has however had regard to the large component of fixed costs that are borne by small consumption customers and has increased the fixed charges in most tariffs by CPI only. This decision does however come at a cost, and the variable component of all tariffs has increased by more than CPI to ensure an appropriate revenue recovery. Regard for the declining block nature of existing Aurora tariffs has also been a factor and Aurora has chosen to specifically increase the 'remaining' component of these tariff types by the largest amount to reflect the overall Australian and international push to send price signals that provide incentives to reduce network demand.
- In relation to the requirement that a Network Tariff have regard for the appropriate allocation of NEM/contestability costs between contestable and non-contestable customers, Aurora Energy notes that:
- None of these costs have been allocated to non-contestable customers, in line with instructions received from the Regulator to this effect.
- The ability of customers to respond to price signals should not be at question with the tariffs that Aurora has prepared for Period 4. Aurora has made newly introduced tariffs available to specific classes of customers because of their ability to respond to the pricing signals that are being provided. The likelihood of customers responding to those signals is, of course, a different matter. To ensure that customers respond appropriately to these new tariffs:
- Aurora consulted with key stakeholders as part of the development of new tariffs;
- feedback that has been received has been incorporated into the design of the new tariffs; and
- prices have been set such that customers should see a discount by moving to the new tariff.

2.3.3. Requirement to Adjust Tariffs to Recover Revenue

Clause 2(d) of the Guideline requires that:

> If, however, as a result of the operation of paragraph (c), the Distribution Network Service Provider may not recover the expected revenue, the provider must adjust its Network Tariffs so as to ensure recovery of expected revenue with minimum distortion to efficient patterns of consumption. Aurora believes that it has met the requirements of clause 2(c) of the Guideline and forecasts to recover its revenue requirement. As such, it has not found it necessary to apply the adjustment as required in clause 2(d).

3. Proposed Network Tariffs for Period 4

This section is to address the Guideline:

2.3(d)(1) "A Network Tariff Pricing Proposal must…set out the proposed Network Tariffs that are to apply for the relevant period…";

2.3(d)(2): "A Network Tariff Pricing Proposal must…set out, for each proposed Network Tariff, the terms and conditions and the charging parameters and the elements of service to which each charging parameter relates…";

2.3(d)(3): "A Network Tariff Pricing Proposal must…detail the bona fide forecast installation numbers and loads and the basis of that forecast for each proposed Network Tariff used in developing the Network Tariff Pricing Proposal…";

2.3(d)(4): "A Network Tariff Pricing Proposal must…set out, for each proposed Network Tariff, the expected revenue for that Network Tariff for the relevant regulatory period and also for the current regulatory period;

2.3(d)(5): "A Network Tariff Pricing Proposal must…detail any proposed amendments, variations or adjustments to the Network Tariff proposed, the justification for the proposed amendments, variations or adjustments and whether these amendments, variations or adjustments are consistent with the Network Tariff Strategy…"; and

2.3(d)(7): "A Network Tariff Pricing Proposal must…set out the nature of any proposed variation or adjustment to the Network Tariff that could occur during the subsequent periods and the basis on which it could occur…"

For simplicity, the Guideline is addressed by tariff class.

3.1. LV General Network – Residential (N01)

MSATS Code AURESGEN

3.1.1. Terms and Conditions

This tariff is for low voltage installations that are premises used wholly or principally as private residential dwellings. A private residential dwelling is a house, flat, home unit, town house or similar qualifying residential premise.

There are no restrictions on the use of the supply (i.e. may be used for general power, heating, water heating, etc.).

Farm outbuildings may be connected on this tariff provided that the connection is through the meters for the farm residence.

A Type 6 meter is the minimum required for installations on this tariff.

3.1.2. Rates

Table 4: Proposed Tariff Rates and Charges for N01

N01	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	36.567	35.812	2.11%
First 500kWh per Quarter	8.146	7.648	6.51%
Next 1000kWh per Quarter	7.535	6.883	9.47%
Remaining Consumption	7.331	6.501	12.77%
TUoS Charge			
First 500kWh per Quarter	3.725	2.939	26.73%
Next 1000kWh per Quarter	3.445	2.645	30.26%
Remaining Consumption	3.352	2.498	34.19%
Meter Charge			
Daily Charge	7.993	7.671	4.20%
Total Charge (NUoS)			
Daily Charge	44.560	43.483	2.48%
First 500kWh per Quarter	11.870	10.587	12.12%
Next 1000kWh per Quarter	10.980	9.528	15.24%
Remaining Consumption	10.683	8.999	18.72%

3.1.3. Estimated Volumes and Revenues

Table 5: Forecast Installation Numbers, Loads and Revenues for N01

NO1	Period 4	Period 3
Customer (installation) days in period	64,913,957	64,086,334
Forecast Loads		
First 500kWh per Quarter	308,735,270	300,749,631
Next 1000kWh per Quarter	327,490,906	319,873,419
Remaining Consumption	146,691,345	183,651,426
Expected Revenue		
Daily Charge	28,925,659	27,866,661
First 500kWh per Quarter	36,648,138	31,840,363
Next 1000kWh per Quarter	35,958,920	30,477,539
Remaining Consumption	15,671,576	16,526,792
Total Tariff Revenue	117,204,293	106,711,355

3.1.4. Variations Since Period 3

The tariff rates were increased in line with the strategy presented in Section 5.1 of this Pricing Proposal. The extra increase in the third step of the consumption is part of the strategy to align the General Network Tariffs N01 and N02 (see Section 6.2 of the NTS for discussion on this point).

3.1.5. Future Variations

It is planned that the rates and charging elements of this Network Tariff and the General Network – Business tariff (N02) will be aligned between Period 2 and Period 5. This is in line with the NTS (see Section 6.2).

Aurora indicated that this tariff maybe made obsolete from 1 July 2010. As the residential Time of Use energy tariff (N13r) will only be introduced to all customers during Period 4, Aurora will not make a decision on the obsolescence of this tariff until a future period.

Aurora will consult with interested parties prior to making a final decision on the potential obsolescence of this tariff in future Periods.

3.2. General Network – Business (N02)

MSATS Code AUBLVGEN

3.2.1. Terms and Conditions

This is the basic, LV Network Tariff for installations that are not private residential dwellings. A private residential dwelling is a house, flat, home unit, town house or similar qualifying residential premise.

There are no restrictions on the use of the supply (i.e. may be used for general power, heating, water heating, etc.)

A Type 6 meter is the minimum required for installations on this tariff.

3.2.2. Rates

Table 6: Proposed Tariff Rates and Charges for N02

N02 Tariff Charge	Period 4	Period 3	% Change
DUoS Charge			
Daily Charge	36.567	35.812	2.11%
First 500kWh per Quarter	8.422	8.175	3.02%
Remaining Consumption	7.331	6.501	12.77%
TUoS Charge			
First 500kWh per Quarter	4.170	3.291	26.72%
Remaining Consumption	3.352	2.498	34.19%
Meter Charge			
Daily Charge	11.545	11.105	3.96%
Total Charge (NUoS)			
Daily Charge	48.112	46.917	2.55%
First 500kWh per Quarter	12.592	11.466	9.82%
Remaining Consumption	10.683	8.999	18.72%

3.2.3. *Estimated Volumes and Revenues*

Table 7: Forecast Installation Numbers, Loads and Expected Revenue for N02

NO2	Period 4	Period 3
Forecast Installation Numbers		
Customer (installation) days in period	13,122,136	13,265,803
Forecast Loads		
First 500kWh per Quarter	49,030,719	51,043,249
Remaining Consumption	741,756,129	744,676,757
Expected Revenue		
Daily Charge	6,313,322	6,223,917
First 500kWh per Quarter	6,174,018	5,852,619
Remaining Consumption	79,244,534	67,013,461
Total Tariff Revenue	91,731,874	79,089,997

3.2.4. *Variations Since Period 3*

The tariff rates were increased in line with the strategy presented in Section 5.1 of this Pricing Proposal. The extra increase in the second step of the consumption is part of the strategy to align the General Network Tariffs N01 and N02 (see Section 6.2 of the NTS for discussion on this point).

3.2.5. *Future Variations*

It is planned that the rates and charging elements of this Network Tariff and the General Network – Residential tariff (N01) will be aligned between Period 2 and Period 5. This is in line with the NTS (see Section 6.2).

Aurora indicated that this tariff maybe made obsolete from 1 July 2010. As the residential Time of Use energy tariff (N13b) will only be introduced to all customers during Period 4, Aurora will not make a decision on the obsolescence of this tariff until a future period.

Aurora will consult with interested parties prior to making a final decision on the potential obsolescence of this tariff in future Periods.

3.3. LV General Network – Business - Nursing Homes (NO2a) - Obsolete

MSATS Code AUBLVNURSE

3.3.1. Terms and Conditions

This LV Network Tariff is applicable only to those businesses registered as Aged Care facilities.

There are no restrictions on the use of the supply (i.e. may be used for general power, heating, water heating, etc.).

A Type 6 meter is the minimum required for installations on this tariff.

This tariff is Obsolete, with no new connections allowed from 1 July 2008.

Please Note: Customers who choose to transfer off any one Obsolete tariff for an installation will lose all rights to all Obsolete tariffs for that installation, i.e. the entire installation will be required to move to currently available published tariffs.

3.3.2. Rates

Table 8: Proposed Tariff Rates and Charges for NO2a

NO2a	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	36.567	35.812	2.11%
First 500kWh per Quarter	8.286	7.664	8.12%
Remaining Consumption	3.729	3.449	8.12%
TUoS Charge			
First 500kWh per Quarter	2.987	2.763	8.11%
Remaining Consumption	2.218	2.052	8.11%
Meter Charge			
Daily Charge	11.545	11.105	3.96%
Total Charge (NUoS)			
Daily Charge	48.112	46.917	2.55%
First 500kWh per Quarter	11.273	10.427	8.11%
Remaining Consumption	5.947	5.501	8.12%

3.3.3. Estimated Volumes and Revenues

Table 9: Forecast Installation Numbers, Loads and Expected Revenues for N02a

NO2a	Period 4	Period 3
Forecast Installation Numbers		
Customer (installation) days in period	31,887	17,103
Forecast Loads		
First 500kWh per Quarter	171,201	84,860
Remaining Consumption	45,308,707	27,723,782
Expected Revenue		
Daily Charge	15,342	8,024
First 500kWh per Quarter	19,300	8,848
Remaining Consumption	2,694,698	1,525,085
Total Tariff Revenue	2,729,339	1,541,958

3.3.4. Variations Since Period 3

The DUoS and TUoS components of this tariff were increased at a rate of 6% above the CPI increase of 2.11% between Period 3 and Period 4. These increases are in line with Section 6.6 of the NTS.

3.3.5. Future Variations

The 2005 Report indicated that Aurora intended to make this Network Tariff Obsolete by 2009, noting that: "Nursing homes generally use much of their energy during off-peak periods and may be better serviced by the Business ToU tariff." To this end, with the approval of the Regulator in the 2003 Determination, Aurora began to align the N02a and N02 tariffs, by increasing the N02a tariff at a rate of CPI + 6% per annum. This is discussed further in Section 6.6 of the NTS.

Aurora introduced LV Time of Use (N13b) and LV Demand Tariffs (N09) (see the NTS Sections 6.3 & 6.4) in Period 3, which should provide attractive alternative tariffs for nursing home operators.

3.4. LV General Network – Business - Same Curtilage (N02b) - Obsolete

MSATS Code AUBLVCURT

3.4.1. Terms and Conditions

This tariff is for rural customers having a single LV connection point but requiring more than one meter due to site layout.

The single connection point must supply an installation qualifying for, and being supplied on the General Network - Residential tariff N01.

There are no restrictions on the use of the supply (i.e. may be used for general power, heating, water heating, etc.)

This tariff is Obsolete, with no new connections allowed from 1 July 2008.

Please Note: Customers who choose to transfer off any one Obsolete tariff for an installation will lose all rights to all Obsolete tariffs for that installation, i.e. the entire installation will be required to move to currently available published tariffs.

A Type 6 meter is the minimum required for installations on this tariff.

3.4.2. Rates

Table 10: Proposed Tariff Rates and Charges for N02b

NO2b	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	7.313	3.581	104.22%
First 500kWh per Quarter	8.422	8.175	3.02%
Remaining Consumption	7.331	6.501	12.77%
TUoS Charge			
First 500kWh per Quarter	4.170	3.291	26.72%
Remaining Consumption	3.352	2.498	34.19%
Meter Charge			
Daily Charge	11.545	11.105	3.96%
Total Charge (NUoS)			
Daily Charge	18.858	14.686	28.41%
First 500kWh per Quarter	12.592	11.466	9.82%
Remaining Consumption	10.683	8.999	18.72%

3.4.3. Estimated Volumes and Revenues

Table 11: Forecast Installation Numbers, Loads and Expected Revenues for N02b

NO2b	**Period 4**	**Period 3**
Forecast Installation Numbers		
Customer (installation) days in period	2,916,259	1,496,135
Forecast Loads		
First 500kWh per Quarter	3,081,572	1,734,663
Remaining Consumption	25,981,684	14,742,424
Expected Revenue	0	0
Daily Charge	549,948	219,722
First 500kWh per Quarter	388,036	198,896
Remaining Consumption	2,775,719	1,326,671
Total	3,713,703	1,745,290

3.4.4. Variations Since Period 3

The rates for this tariff were increased in line with the strategy presented in Section 5.1 of this Pricing Proposal. The daily charge for this tariff has been set at 20% of the charge for tariff N02, which is consistent with Section 6.7 of the NTS.

3.4.5. Future Variations

Aurora intends to phase out this tariff over 10 years, as discussed in Section 6.7 of the NTS. This is the third year in that process, with customers receiving an 80% discount on the daily charge.

3.5. *LV Aurora Pay As You Go (N13) - Obsolete*

MSATS Code AUPAYG

3.5.1. Terms and Conditions

This tariff supports the *Aurora Pay As You Go* product offered by Aurora Retail, and is not to be used for any other application.

This tariff is for low voltage installations that are premises used wholly or principally as private residential dwellings. A private residential dwelling is a house, flat, home unit, town house or similar qualifying residential premise.

There are no restrictions on the use of the supply (i.e. may be used for general power, heating, water heating, etc.).

This tariff may not be used in conjunction with any other Network Tariff.

This tariff is Obsolete, with no new connections allowed from 1 July 2009.

Please Note: Customers who choose to transfer off any one Obsolete tariff for an installation will lose all rights to all Obsolete tariffs for that installation, i.e. the entire installation will be required to move to currently available published tariffs.

Metering for this tariff is provided by Aurora Retail.

3.5.2. Rates

Table 12: Proposed Tariff Rates and Charges for N13

N13	**Period 4**	**Period 3**	**% Change P4**
DUoS Charge			
Daily Charge	36.567	35.812	2.11%
All Energy	4.554	5.258	-13.39%
TUoS Charge			
All Energy	2.206	2.110	4.53%
Total Charge (NUoS)			
Daily Charge	36.567	35.812	2.11%
All Energy	6.760	7.368	-8.26%

3.5.3. Estimated Volumes and Revenues

Table 13: Forecast Installation Numbers, Loads and Revenues for N13

N13	Period 4	Period 3
Forecast Installation Numbers		
Customer (installation) days in period	14,673,000	16,375,611
Forecast Loads		
All Energy	385,308,425	435,369,838
Expected Revenue		
Daily Charge	5,365,476	5,864,434
All Energy	26,045,314	32,078,050
Total Tariff Revenue	31,410,790	37,942,483

3.5.4. Variations Since Period 3

The overall tariff escalation rates were varied as per the strategy presented in Section 5.1. The daily charge for this tariff has been aligned with tariff N01 as the connection characteristics of PAYG customers are consistent with all other residential customers.

The energy charge for this tariff has been set to better reflect the ToU characteristics of this tariff and to be consistent with the new ToU tariff N13r. This has meant that the energy charge for this tariff has decreased above the average for other tariffs.

This tariff has been made Obsolete with the introduction of the LV ToU Network Tariff (N13r) with no new connections from 1 July 2009.

3.5.5. Future Variations

This tariff will be deleted when sites that are metered with an Aurora Retail owned meter are below a manageable number for state-wide meter upgrades.

3.6. LV General Residential Time of Use Tariff (N13r)

MSATS Code: AURESTOU.

3.6.1. Terms and Conditions

This tariff is for low voltage installations that are premises used wholly or principally as private residential dwellings. A private residential dwelling is a house, flat, home unit, town house or similar qualifying residential premise.

There are no restrictions on the use for the supply.

Note: Farm outbuildings may be connected on this tariff provided that the connection is through the meters for the farm residence.

A site that is supplied under this tariff may move to Network Tariff N01.

A meter capable of recording time of use data is required for installations on this tariff.

The Use of System charges applicable for this tariff are composed of the following charging components:

a) DUOS

   i) A fixed daily charge; and

   ii) An energy-based charge; the rate of the energy charge varies according to the time of day at which energy is consumed, with the periods being as identified in Table 14.

b) TUOS

   i) An energy-based charge; the rate of the energy charge varies according to the time of day at which energy is consumed, with the periods being as identified in Table 14.

c) Metering

   i) A charge for the provision of metering services may apply, depending upon whether or not Aurora is appointed as Metering Provider.

For connection on this tariff, water heating systems:

- must comply with Australian Standard 1056, Storage Water Heaters; and
- should comply with approved Australian Standards AS 3500.4.1 - 1997 and 3500.4.2:1997, National Plumbing and Drainage Code, Part 4 Hot Water Supply Systems and all amendments; non-compliant systems may be refused connection or disconnected.

3.6.2. *ToU Time Periods*

Table 14: Time Periods for Residential ToU Tariff N13r

Time Period	Tariff Rate
Week Day (0700 – 1100) (Monday – Friday)	Peak
Week Day (1100 – 1630) (Monday – Friday)	Shoulder
Week Day (1630 – 2200) (Monday – Friday)	Peak
Weekend Day (0700 – 2200) (Saturday & Sunday)	Shoulder
Any Day (2200 – 0700) (Monday – Sunday)	Off-peak

3.6.3. *Rates*

Table 15: Proposed Tariff Rates and Charges for N13r

N13r	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	36.567	35.812	2.11%
Peak Energy	7.840	6.883	13.91%
Shoulder Energy	4.850	4.267	13.67%
Off-Peak Energy	0.365	0.343	6.38%
TUoS Charge			
Peak Energy	3.445	2.645	30.26%
Shoulder Energy	2.317	1.784	29.90%
Off-Peak Energy	0.625	0.494	26.60%
Meter Charge			
Daily Charge	9.816	9.556	2.72%
Total Charge (NUoS)			
Daily Charge	46.383	45.368	2.24%
Peak Energy	11.286	9.528	18.45%
Shoulder Energy	7.167	6.051	18.45%
Off-Peak Energy	0.990	0.837	18.32%

3.6.4. *Estimated Volumes and Revenues*

Table 16: Forecast Installation Numbers, Loads and Revenues for N13r

N13r	Period 4	Period 3
Forecast Installation Numbers		
Customer (installation) days in period	1,100,475	540,395
Forecast Loads		
Peak Energy	9,120,643	5,440,480
Shoulder Energy	7,320,693	5,010,332
Off-Peak Energy	7,672,668	3,916,393
Expected Revenue		
Daily Charge	510,433	245,166
Peak Energy	1,029,319	518,369
Shoulder Energy	524,709	303,175
Off-Peak Energy	75,983	32,780
Total Tariff Revenue	2,140,444	1,099,491

3.6.5. *Variations Since Period 3*

The tariff rates were increased in line with the strategy presented in Section 5.1 of this Pricing Proposal.

This tariff is now available to all low voltage premises used wholly or principally as private residential dwellings.

3.6.6. *Future Variations*

Aside from variations due to allowable adjustments in AARR and rebalancing between revenues collected from each tariff class and between fixed and variable costs, no changes are planned to this tariff.

3.7. LV General Business Time of Use Tariff (N13b)

MSATS Code: AUBUSTOU

3.7.1. Terms and Conditions

This is the basic, time of use LV Network Tariff for installations that are not private residential dwellings. A private residential dwelling is a house, flat, home unit, town house or similar qualifying residential premise.

There are no restrictions on the use of the supply (i.e. may be used for general power, heating, water heating, etc.)

A site that is supplied under this tariff may not move to Network Tariffs N02a or N02b.

A meter capable of recording time of use data is required for installations on this tariff.

The Use of System charges applicable for this tariff is composed of the following charging components:

a) DUOS

- i) A fixed daily charge; and
- ii) An energy-based charge; the rate of the energy charge varies according to the time of day at which energy is consumed, with the periods being as identified in Table 17.

b) TUOS

- i) An energy-based charge; the rate of the energy charge varies according to the time of day at which energy is consumed, with the periods being as identified in Table 17.

c) Metering

- i) A charge for the provision of metering services may apply, depending upon whether or not Aurora is appointed as Metering Provider.

For connection on this tariff, water heating systems:

- must comply with Australian Standard 1056, Storage Water Heaters; and
- should comply with approved Australian Standards AS 3500.4.1 - 1997 and 3500.4.2:1997, National Plumbing and Drainage Code, Part 4 Hot Water Supply Systems and all amendments; non-compliant systems may be refused connection or disconnected.

3.7.2. *ToU Time Periods*

Table 17: Time Periods for General Business ToU Tariff

Time Period	Tariff Rate
Week Day (0700 – 2200) (Monday – Friday)	Peak
Weekend Day (0700 – 2200) (Saturday & Sunday)	Shoulder
Any Day (2200 – 0700) (Monday – Sunday)	Off-peak

3.7.3. *Rates*

Table 18: Proposed Tariff Rates and Charges for N13b

N13B	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	36.567	35.812	2%
Peak Energy	7.840	6.501	21%
Shoulder Energy	4.850	4.037	20%
Off-Peak Energy	0.365	0.343	6%
TUoS Charge			
Peak Energy	3.445	2.498	38%
Shoulder Energy	2.317	1.696	37%
Off-Peak Energy	0.625	0.494	27%
Meter Charge			
Daily Charge	14.688	14.189	4%
Total Charge (NUoS)			
Daily Charge	51.255	50.001	3%
Peak Energy	11.286	8.999	25%
Shoulder Energy	7.167	5.733	25%
Off-Peak Energy	0.990	0.837	18%

3.7.4. *Estimated Volumes and Revenues*

Table 19: Forecast Installation Numbers, Loads and Revenues for N13b

N13B	**Period 4**	**Period 3**
Forecast Installation Numbers		
Customer (installation) days in period	114,816	15,707
Forecast Loads		
Peak Energy	6,149,919	5,252,704
Shoulder Energy	6,710,394	9,673,086
Off-Peak Energy	9,243,398	12,882,852
Expected Revenue		
Daily Charge	58,849	7,853
Peak Energy	694,055	472,691
Shoulder Energy	480,966	554,558
Off-Peak Energy	91,538	107,829
Total Tariff Revenue	1,325,408	1,142,932

3.7.5. *Variations Since Period 3*

The tariff rates were increased in line with the strategy presented in Section 5.1 of this Pricing Proposal.

This tariff is now available to all LV installations that are not private residential dwellings.

3.7.6. *Future Variations*

Aside from variations due to allowable adjustments in AARR and rebalancing between revenues collected from each tariff class and between fixed and variable costs, no changes are planned to this tariff.

3.8. LV Uncontrolled Energy (N05)

MSATS Code AUHEATUNCO

3.8.1. Terms and Conditions

3.8.1.1. General Conditions

This tariff is for low voltage installations.

In installations that are private residential dwellings, this tariff:

- is for water heating and/or residential space heating and/or domestic indoor pool heating only, and
- may only be used if the premises also has a current connection on tariff N01.

In installations that are not private residential dwellings, this tariff:

- is for water heating only, and
- may only be used if the premises also has a current connection on Network Tariff N02 or N02a.

With the exception of thermal-storage space heaters or thermal-storage water heaters, this tariff N05 may not be applied to any apparatus also connected under another Network Tariff.

A private residential dwelling is a house, flat, home unit, town house or similar qualifying residential premise.

A Type 6 meter is the minimum required for installations on this tariff.

3.8.1.2. Requirements of Water Heating Systems

In installations that are private residential dwellings, for connection on this tariff, the water heating systems must:

- comply with Australian Standard 1056, Storage Water Heaters; and
- if the delivery rating of the water heating system is less than or equal to 500 litres, have an electric heating unit rating not exceeding 16 Watts per litre; or
- if the delivery rating of the water heating system is greater than 500 litres, have an electric heating unit rating not exceeding 32 Watts per litre.

Where a private residential installation has a water storage heater installed, and the delivery rating is greater than 20 litres but less than 100 litres, the limit of 16 Watts per litre may be exceeded by that individual water storage heater. Only one water storage unit, with a delivery rating between 20 and 100 litres that exceeds the 16 Watts per litre may be installed at a private residential dwelling.

In installations that are not private residential dwellings, for connection on this tariff, the water heating systems must:

- comply with Australian Standard 1056, Storage Water Heaters; and

- if the delivery rating of the water heating system is less than or equal to 500 litres, have an electric heating unit rating not exceeding 16 Watts per litre; or
- if the delivery rating of the water heating system is greater than 500 litres, have an electric heating unit rating not exceeding 32 Watts per litre.

Where a non-private residential installation has two or more water storage heaters installed, and the combined delivery rating is greater than 500 litres, the limit of 32 Watts per litre may be exceeded by an individual water storage heater provided that the ratio of the total wattage of all the water heating units to the total delivery rating does not exceed 32 Watts per litre.

Dairy water heaters containing main and booster heating units may have both heating units connected under this tariff.

Dairy water heaters are not required to comply with the Australian Standard 1056.

The electric heating unit ratings do not apply to Dairy water heaters.

3.8.1.3. Requirements of Residential Space Heating Systems

Permanently installed wired-in electric heater(s) may be eligible with this tariff on condition that the wiring of any electric heater is installed by a registered electrician in accordance with AS/NZS 3000 wiring rules and associated regulations and acts, and one of the following conditions are met:

1) If a residence has a permanently installed wired-in electric heater with an output of 3.5 kW in a living area, on a single functional switch then this, and any additional permanently wired space heaters throughout the residence, may be installed on this tariff.
2) A total rating of at least 5 kW of the same heating system installed throughout the residence. This heating system must be the priority heating system of the main living area and must have a single functional switch in each heated area throughout the residence. However where a ducted heating system is installed, the control switch must be located near the heating unit in order to qualify for this tariff.
3) Heating in secondary areas such as bedrooms and hallways if the residence has Off Peak storage heating in the living area(s) as its priority source of heating. The secondary heating system should be a permanently connected single propriety heating system with a total of 5 kW or more heating capacity.

3.8.1.4. Requirements of Domestic Indoor Pool Heating Systems

Private domestic indoor swimming pools are allowed under Tariff N05 if an installation:

a. complies with the residential space heating system rules as provided above; and
b. has an electrical input power limit of 400 watt/m^2 of surface area.

This tariff will be applied following an Electrical Works Request to Aurora from an electrical contractor. Upon receipt of the Electrical Works Request, the tariff will be applied to a customer's account from the date the meter was changed or the day after the last quarterly read, whichever is the later.

Spas are not eligible for Network Tariff N05

3.8.2. Rates

Table 20: Proposed Tariff Rates and Charges for N05

N05	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	3.657	3.581	2.11%
All Energy	1.433	1.345	6.53%
TUoS Charge			
All Energy	2.217	1.749	26.75%
Meter Charge			
Daily Charge	7.933	7.614	4.19%
Total Charge (NUoS)			
Daily Charge	11.590	11.195	3.53%
All Energy	3.650	3.094	17.96%

3.8.3. Estimated Volumes and Revenues

Table 21: Forecast Installation Numbers, Loads and Expected Revenues for N05

N05	Period 4	Period 3
Forecast Installation Numbers		
Customer (installation) days in period	60,700,965	60,147,303
Forecast Loads		
All Energy	876,689,330	866,711,228
Expected Revenue		
Daily Charge	7,035,060	6,733,491
All Energy	31,996,672	26,816,045
Total Tariff Revenue	39,031,732	33,549,536

3.8.4. Variations Since Period 3

The rates for this tariff were increased in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.8.5. Future Variations

Aurora has introduced an LV ToU tariff for all customers. In due course, customers currently on N05 will be transferred to this new tariff, which will provide benefits to those customers who can manage their load. Network Tariff N05 may be made Obsolete in future Periods.

Aurora will consult with interested parties prior to making a final decision on the potential obsolescence of this tariff in future Periods.

3.9. Controlled Heating (N06)

MSATS Code AUHEATCONT

3.9.1. Terms and Conditions

3.9.1.1. General Conditions

This tariff is for low voltage installations.

In installations that are private residential dwellings, this tariff:

- is for water heating and/or residential space heating and/or other "wired in" appliances as approved by Aurora Network.
- may be used for heating swimming pools, including those that incorporate a spa. Note that an individual spa from which the water goes to waste after use may not be connected on this tariff.
- may only be used if the premises also has a current connection on tariff N01.

In installations that are not private residential dwellings, this tariff:

- is for water heating and/or space heating and/or other "wired in" appliances as approved by Aurora Network.
- may only be used if the premises also has a current connection on Network Tariff N02, N02a.

With the exception of thermal-storage space heaters or thermal-storage water heaters, this tariff N06 may not be applied to any apparatus also connected under another Network Tariff.

A private residential dwelling is a house, flat, home unit, town house or similar qualifying residential premise.

In all installations, this tariff N06 may not be used for circuits supplying general purpose outlets, other than existing outlets supplied on this tariff.

A Type 6 meter is the minimum required for installations on this tariff.

3.9.1.2. Time of Use Availability

This tariff is a "time of use" tariff. Energy to installations connected on this tariff will be available daily for:

- at least nine hours between 20:00 hours and 07:00 hours the following day; and
- a further two hours between 13:00 hours and 16:30 hours.

Aurora Network will choose the actual times during these periods that the energy will be available.

3.9.1.3. Requirements of Water Heating Systems

In installations that are private residential dwellings, for connection on this tariff, the water heating systems:

- must comply with Australian Standard 1056, Storage Water Heaters; and

- should comply with approved Australian Standards AS 3500.4.1 - 1997 and 3500.4.2:1997, National Plumbing and Drainage Code, Part 4 Hot Water Supply Systems and all amendments; non-compliant systems may be refused connection or disconnected.

In installations that are not private residential dwellings, for connection on this tariff, the water heating systems:

- must comply with Australian Standard 1056, Storage Water Heaters; and
- should comply with approved Australian Standards AS 3500.4.1 - 1997 and 3500.4.2:1997, National Plumbing and Drainage Code, Part 4 Hot Water Supply Systems and all amendments; non-compliant systems may be refused connection or disconnected.

3.9.2. Rates

Table 22: Proposed Tariff Rates and Charges for N06

N06	**Period 4**	**Period 3**	**% Change P4**
DUoS Charge			
Daily Charge	7.180	7.032	2.11%
All Energy	0.365	0.343	6.38%
TUoS Charge			
All Energy	0.625	0.494	26.60%
Meter Charge			
Daily Charge	8.133	7.813	4.10%
Total Charge (NUoS)			
Daily Charge	15.313	14.845	3.15%
All Energy	0.990	0.837	18.32%

3.9.3. Estimated Volumes and Revenues

Table 23: Forecast Installation Numbers, Loads and Expected Revenues for N06

N06	**Period 4**	**Period 3**
Forecast Installation Numbers		
Customer (installation) days in period	11,005,517	11,641,515
Forecast Loads		
All Energy	112,841,352	115,838,440
Expected Revenue		
Daily Charge	1,685,304	1,728,183
All Energy	1,117,471	969,568
Total Tariff Revenue	2,802,775	2,697,751

3.9.4. Variations Since Period 3

The rates for this tariff were increased in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.9.5. Future Variations

Aurora has introduced an LV ToU tariff for all customers in Period 4. It is envisaged that customers currently on N06 will be transferred, in due course, to this new tariff, which will provide benefits to those customers who can manage their load. Network Tariff N06 will be made Obsolete after 1 July 2011.

Aurora will consult with interested parties prior to making a final decision on the potential obsolescence of this tariff in Period 5.

3.10. LV Controlled Heating (N06a)

MSATS Code AUOFFPEAK

3.10.1. Terms and Conditions

3.10.1.1. General Conditions

This tariff is for low voltage installations.

In installations that are private residential dwellings, this tariff:

- is for water heating and/or residential space heating and/or other circuits as approved by Aurora Network.
- may be used for heating swimming pools, including those that incorporate a spa. Note that an individual spa from which the water goes to waste after use may not be connected on this tariff.
- may only be used if the premises also has a current connection on tariff N01 or N13r.

In installations that are not private residential dwellings, this tariff:

- is for water heating and/or space heating and/or other circuits as approved by Aurora Network.
- may only be used if the premises also has a current connection on Network Tariff N02 or N13b.

A private residential dwelling is a house, flat, home unit, town house or similar qualifying residential premise.

In all installations, this tariff N06a may be used for circuits supplying general purpose outlets.

A Type 6 meter is the minimum required for installations on this tariff.

3.10.1.2. Time of Use Availability

This tariff is a "time of use" tariff. Energy to installations connected on this tariff will be available between 22:00 hours and 07:00 hours the following day.

3.10.1.3. Requirements of Water Heating Systems

In installations that are private residential dwellings, for connection on this tariff, the water heating systems:

- must comply with Australian Standard 1056, Storage Water Heaters; and
- should comply with approved Australian Standards AS 3500.4.1 - 1997 and 3500.4.2:1997, National Plumbing and Drainage Code, Part 4 Hot Water Supply Systems and all amendments; non-compliant systems may be refused connection or disconnected.

In installations that are not private residential dwellings, for connection on this tariff, the water heating systems:

- must comply with Australian Standard 1056, Storage Water Heaters; and
- should comply with approved Australian Standards AS 3500.4.1 - 1997 and 3500.4.2:1997, National Plumbing and Drainage Code, Part 4 Hot Water Supply Systems and all amendments; non-compliant systems may be refused connection or disconnected.

3.10.2. Rates

Table 24: Proposed Tariff Rates and Charges for N06a

N06a	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	7.180	7.032	2.11%
All Energy	0.347	0.326	6.44%
TUoS Charge			
All Energy	0.594	0.469	26.65%
Meter Charge			
Daily Charge	8.133	7.813	4.10%
Total Charge (NUoS)			
Daily Charge	15.313	14.845	3.15%
All Energy	0.941	0.795	18.36%

3.10.3. Estimated Volumes and Revenues

Table 25: Forecast Installation Numbers, Loads and Expected Revenues for N06a

N06a	Period 4	Period 3
Forecast Installation Numbers		
Customer (installation) days in period	0	0
Forecast Loads		
All Energy	0	0
Expected Revenue		
Daily Charge	0	0
All Energy	0	0
Total Tariff Revenue	0	0

3.10.4. Variations Since Period 3

The rates for this tariff were increased in line with the strategy presented in Section 5.1 of this Pricing Proposal. This tariff is also available to customers on Network Tariffs N01 and N02

3.10.5. Future Variations

Aside from variations due to allowable adjustments in AARR and rebalancing between revenues collected from each tariff class and between fixed and variable costs, no changes are planned to this tariff.

3.11. Demand – kW (N03) - Obsolete

MSATS Code AUBLVDMKW

3.11.1. Terms and Conditions

This tariff is for installations taking LV 3-phase supply.

There are no restrictions on the use of the supply (i.e. may be used for general power, heating, water heating, etc.).

This tariff is Obsolete with no new connections allowed. The replacement LV demand tariff is N09.

Please note: that customers that choose to transfer off any one Obsolete tariff for an installation will lose all rights to all Obsolete tariffs for that installation, i.e. the entire installation will be required to move to currently available published tariffs.

A Type 6 meter is the minimum required for installations on this tariff.

3.11.2. Rates

Table 26: Proposed Tariff Rates and Charges for N03

N03	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	196.300	188.752	4.00%
All Energy Charge	1.765	1.628	8.42%
First 250kW Demand	30.933	28.515	8.48%
Additional Demand	27.885	25.704	8.49%
TUoS Charge			
All Energy Charge	0.963	0.746	29.09%
First 250kW Demand	26.339	20.406	29.07%
Additional Demand	23.737	18.389	29.08%
Meter Charge			
Daily Charge	14.687	14.188	3.52%
Total Charge (NUoS)			
Daily Charge	210.987	202.940	3.97%
All Energy Charge	2.728	2.374	14.91%
First 250kW Demand	57.272	48.921	17.07%
Additional Demand	51.622	44.093	17.08%

3.11.3. Estimated Volumes and Revenues

Table 27: Forecast Installation Numbers, Loads and Expected Revenue for N03

N03	Period 4	Period 3
Forecast Installation Numbers		
Customer (installation) days in period	104,838	125,276
Forecast Loads		
All Energy	83,748,720	120,509,624
First 250kW Demand	3,580,329	8,350,013
Additional Demand	216,969	5,078,330
Expected Revenue		
Daily Charge	221,195	254,235
All Energy	2,284,665	2,860,898
First 250kW Demand	2,050,526	4,084,910
Additional Demand	112,004	2,239,188
Total Tariff Revenue	4,668,390	9,439,232

3.11.4. Variations Since Period 3

The rates for this tariff were varied in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.11.5. Future Variations

Aurora intends to transition all existing installations on this tariff to Network Tariff N09. This accords with the NTS (Section 6.4), and was proposed in the 2005 Report (Section 6.1). Aurora will work with affected customers to minimise the impacts due to transferral.

Network Tariff LV kW Demand N03 will be deleted from the suite of tariffs and consequently will not be available after 1 July 2012.

3.12. LV Metered Demand (kVA) Tariff (N09)

MSATS Code AUBLVDMKVA

3.12.1. Terms and Conditions

This tariff is only for installations taking LV 3-phase supply.

There are no restrictions on the use of the supply; that is, electricity taken on this tariff may be used for general power, heating, water heating, etc.

A Type 6 meter is the minimum required for installations on this tariff.

3.12.2. Rates

Table 28: Proposed Tariff Rates and Charges for N09

N09	**Period 4**	**Period 3**	**% Change P4**
DUoS Charge			
Daily Charge	178.455	174.770	2.11%
All Energy Charge	1.605	1.507	6.49%
First 250kVA Demand	23.903	22.442	6.51%
Additional Demand	21.547	20.230	6.51%
TUoS Charge			
All Energy Charge	0.876	0.691	26.71%
First 250kVA Demand	20.353	16.060	26.73%
Additional Demand	18.342	14.473	26.73%
Meter Charge			
Daily Charge	14.687	14.188	3.52%
Total Charge (NUoS)			
Daily Charge	193.142	188.958	2.21%
All Energy Charge	2.480	2.198	12.85%
First 250kVA Demand	44.256	38.502	14.94%
Additional Demand	39.890	34.703	14.95%

3.12.3. Estimated Volumes and Revenues

Table 29: Forecast Installation Numbers, Loads and Expected Revenues for N09

N09	**Period 4**	**Period 3**
Forecast Installation Numbers		
Customer (installation) days in period	202,982	196,654
Forecast Loads		
All Energy	468,383,531	449,288,183
First 250kVA Demand	30,789,180	27,710,940
Additional Demand	15,333,379	14,485,814
Expected Revenue	P4 Tariff Charge	P3 Tariff Charge
Daily Charge	392,042	371,593
All Energy	11,617,568	9,875,354
First 250kVA Demand	13,626,010	10,669,266
Additional Demand	6,116,444	5,027,012
Total Tariff Revenue	31,752,064	25,943,226

3.12.4. Variations Since Period 3

The rates for this tariff were generally varied in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.12.5. Future Variations

Aside from variations due to allowable adjustments in AARR and rebalancing between revenues collected from each tariff class and between fixed and variable costs, no changes are planned to this tariff.

3.13. LV Day/Night (Irrigation) Tariff (N08) - Obsolete

MSATS Code AUIRRIG

3.13.1. Terms and Conditions

This Network Tariff is for primary producers' business installations that are used solely for the irrigation of crops, which must be classified as ANZSIC class 01.

A Type 6 meter is the minimum required for installations on this tariff.

This tariff is Obsolete; no new connections are allowed on this tariff after 1 July 2009.

Existing sites that are connected on Network Tariff N08 at 1 July 2009 may remain on that tariff.

Please note: Customers who choose to transfer off any one Obsolete tariff for and installation will lose all rights to all Obsolete tariffs for that installation, i.e. the entire installation will be required to move to currently available tariffs.

3.13.2. Time of Use Availability

This tariff is a simple "time of use" tariff, with different rates for "peak" and "off-peak" consumption.

The off-peak rate will be available daily for not less than ten hours between 20:00 hours and 07:00 hours the following day. In general, the "window" will be of 10 hour's duration. Subject to network constraints and at the discretion of Aurora, an 11 hour window may be available upon request.

To provide a "staggered start" to ensure distribution network stability, the off-peak window for individual customers will start between 20:00 and 21:00, and end between 06:00 and 07:00 the following day.

Aurora will arrange the start and finish times.

All times are in Australian Eastern Standard Time.

3.13.3. Rates

Table 30: Proposed Tariff Rates and Charges for N08

N08	**Period 4**	**Period 3**	**% Change P4**
DUoS Charge			
Daily Charge	175.721	172.092	2.11%
Day Energy Charge	8.422	8.175	3.02%
Night Energy Charge	0.365	0.343	6.38%
TUoS Charge			
Day Energy Charge	4.170	3.291	26.72%
Night Energy Charge	0.625	0.494	26.60%
Meter Charge			
Daily Charge	14.349	13.857	3.55%
Total Charge (NUoS)			
Daily Charge	190.070	185.949	2.22%
Day Energy Charge	12.592	11.466	9.82%
Night Energy Charge	0.990	0.837	18.32%

3.13.4. Estimated Volumes and Revenues

Table 31: Forecast Installation Numbers, Loads and Expected Revenues for N08

N08	Period 4	Period 3
Forecast Installation Numbers		
Customer (installation) days in period	1,127,928	1,121,736
Forecast Loads		
Day Energy	44,788,677	44,644,161
Night Energy	58,938,013	63,899,194
Expected Revenue		
Daily Charge	2,143,848	2,085,857
Day Energy	5,639,854	5,118,899
Night Energy	583,665	534,836
Total Tariff Revenue	8,367,367	7,739,593

3.13.5. Variations Since Period 3

The rates for this tariff were generally varied in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.13.6. Future Variations

Aurora has introduced an LV ToU Irrigation tariff (N08a) and other kVA demand tariffs from Period 3. These demand management incentive Network Tariffs will provide an attractive alternative to the current N08. The currently available LV Metered Demand (kVA) tariff N09 may also be a viable alternative to this tariff N08 depending upon individual user's usage patterns.

Network Tariff LV Day/Night (Irrigation) N08 will be deleted from the suite of tariffs and consequently will not be available after 1 July 2012.

3.14. LV Time of Use Irrigation Tariff (N08a)

MSATS Code: AUTOUIRR.

3.14.1. Terms and Conditions

This Network Tariff is for primary producers' business installations that are used solely for the irrigation of crops, which must be classified as ANZSIC class 01.

A meter capable of recording time of use data is required for installations on this tariff.

The Use of System charges applicable for this tariff is composed of the following charging components:

a) DUOS

   i) A fixed daily charge; and

   ii) An energy-based charge; the rate of the energy charge varies according to the time of day at which energy is consumed, with the periods being as identified in Table 32.

b) TUOS

   i) An energy-based charge; the rate of the energy charge varies according to the time of day at which energy is consumed, with the periods being as identified in Table 32.

c) Metering

   i) A charge for the provision of metering services may apply, depending upon whether or not Aurora is appointed as Metering Provider

Table 32: Time Periods for Irrigation Tariff

Time Period	Summer (1 Oct - 31 Mar)	Winter (1 Apr - 30 Sep)
Week Day (0700 – 2200) (Monday – Friday)	Shoulder	Peak
Weekend Day (0700 – 2200) (Saturday & Sunday)	Off-peak	Shoulder
Any Day (2200 – 0700) (Monday – Sunday)	Off-peak	Off-peak

3.14.2. Rates

Table 33: Proposed Tariff Rates and Charges for N08a

N08a	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	158.830	155.550	2.11%
Peak Energy	8.422	8.175	3.02%
Shoulder Energy	5.199	5.042	3.11%
Off-Peak Energy	0.365	0.343	6.51%
TUoS Charge			
Peak Energy	4.170	3.291	26.72%
Shoulder Energy	2.742	2.162	26.83%
Off-Peak Energy	0.600	0.469	27.92%
Meter Charge			
Daily Charge	14.688	14.189	3.52%
Total Charge (NUoS)			
Daily Charge	173.518	169.739	2.23%
Peak Energy	12.592	11.466	9.82%
Shoulder Energy	7.941	7.204	10.23%
Off-Peak Energy	0.965	0.812	18.88%

3.14.3. Estimated Volumes and Revenues

Table 34: Forecast Installation Numbers, Loads and Revenues for N08a

N08a	Period 4	Period 3
Forecast Installation Numbers		
Customer (installation) days in period	65,872	59,039
Forecast Loads		
Peak Energy	1,562,380	1,073,173
Shoulder Energy	2,348,406	1,902,949
Off-Peak Energy	3,155,419	2,736,686
Expected Revenue		
Daily Charge	114,299	100,212
Peak Energy	196,741	123,050
Shoulder Energy	186,475	137,088
Off-Peak Energy	30,404	22,222
Total Tariff Revenue	527,919	382,572

3.14.4. Variations Since Period 3

The rates for this tariff were increased in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.14.5. Future Variations

Aside from variations due to allowable adjustments in AARR and rebalancing between revenues collected from each tariff class and between fixed and variable costs, no changes are planned to this tariff.

3.15. LV Small Unmetered (N07)

MSATS Code AUUMS

3.15.1. Terms and Conditions

This tariff is for small, LV, low demand installations with a relatively constant load profile. For example:

- illuminated street signs;
- public telephone kiosks;
- electric fences;
- two-way radio transmitters;
- fixed steady wattage installations;
- traffic lights; and
- level crossings.

All installations on this tariff must have all components permanently connected. For the avoidance of doubt, an installation containing a power point does not qualify for this Network Tariff.

Exception: Shows & public functions qualify for this tariff N07. Shows and public functions on this tariff may have installed power points.

3.15.2. Rates

Table 35: Proposed Tariff Rates and Charges for N07

N07	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	27.425	26.859	2.11%
All Energy Charge	9.264	11.589	-20.06%
TUoS Charge			
All Energy Charge	4.587	2.051	123.67%
Total Charge (NUoS)			
Daily Charge	27.425	26.859	2.11%
All Energy Charge	13.851	13.640	1.55%

3.15.3. Estimated Volumes and Revenues

Table 36: Forecast Installation Numbers, Loads and Expected Revenues for NO7

NO7	**Period 4**	**Period 3**
Forecast Installation Numbers		
Customer (installation) days in period	531,114	388,695
Forecast Loads		
All Energy	7,762,213	431,713
Expected Revenue		
Daily Charge	145,659	104,400
All Energy	1,075,172	58,886
Total Tariff Revenue	1,220,830	163,285

3.15.4. Variations Since Period 3

The components within this tariff were varied with the strategy presented in Section 5.1 of this Pricing Proposal.

3.15.5. Future Variations

Aside from variations due to allowable adjustments in AARR and rebalancing between revenues collected from each tariff class and between fixed and variable costs, no changes are planned to this tariff.

3.16. HV Demand kW (N11) – Obsolete

MSATS Code AUBHVDMKW

3.16.1. Terms and Conditions

This tariff is for customers taking HV supply.

There are no restrictions on the use of the supply.

The customer must supply its own transformers & switchgear for installations connected on this tariff.

Metering of consumption is at the HV connection point.

This tariff is Obsolete; no new connections are allowed on this tariff.

Please note: Customers who choose to transfer off any one Obsolete tariff for an installation will lose all rights to all Obsolete tariffs for that installation, i.e. the entire installation will be required to move to currently available published tariffs.

3.16.2. Rates

Table 37: Proposed Tariff Rates and Charges for N11

N11	**Period 4**	**Period 3**	**% Change P4**
DUoS Charge			
Daily Charge	134.468	129.298	4.00%
All Energy Charge	0.110	0.102	7.77%
Demand Charge	28.450	26.226	8.48%
TUoS Charge			
All Energy Charge	1.473	1.140	29.17%
Demand Charge	2.638	2.044	29.07%
Meter Charge			
Daily Charge	63.800	61.394	3.92%
Total Charge (NUoS)			
Daily Charge	198.268	190.692	3.97%
All Energy Charge	1.582	1.242	27.41%
Demand Charge	31.089	28.270	9.97%

3.16.3. Estimated Volumes and Revenues

Table 38: Forecast Installation Numbers, Loads and Expected Revenues for N11

N11	**Period 4**	**Period 3**
Forecast Installation Numbers		
Customer (installation) days in period	3,668	6,570
Forecast Loads		
All Energy	6,306,683	20,754,980
Demand	164,395	758,653
Expected Revenue		
Daily Charge	7,273	12,528
All Energy	99,802	257,777
Demand	51,108	214,471
Total Tariff Revenue	158,183	484,776

3.16.4. Variations Since Period 3

The rates for this tariff were varied in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.16.5. Future Variations

This tariff is Obsolete, as discussed in Sections 6.3 & 6.4 of the NTS.

Over the course of this Regulatory period, Aurora intends to transition installations on this tariff to the HV Specified Demand Tariff.

Network Tariff HV kW Demand (N11) will be deleted from the suite of tariffs and consequently will not be available after 1 July 2012.

3.17. HV Demand kVA (N10) - Obsolete

MSATS Code AUBHCDMKVA

3.17.1. Terms and Conditions

This tariff is for customers taking no HV single or dual phase supply.

There are no restrictions on the use of the supply; that is, the electricity may be used for general power, heating, water heating, etc.

The customer must supply its own transformers & switchgear for installations connected on this tariff.

Metering of consumption is at the HV connection point.

This tariff is Obsolete; no new connections are allowed on this tariff.

Please note: Customers who choose to transfer off any one Obsolete tariff for an installation will lose all rights to all Obsolete tariffs for that installation, i.e. the entire installation will be required to move to currently available tariffs.

3.17.2. Rates

Table 39: Proposed Tariff Rates and Charges for N10

N10	Period 4	Period 3	% Change P4
DUoS Charge			
Daily Charge	122.244	119.720	2.11%
All Energy Charge	0.100	0.094	6.31%
Demand Charge	21.984	20.641	6.51%
TUoS Charge			
All Energy Charge	1.339	1.056	26.77%
Demand Charge	2.039	1.609	26.70%
Meter Charge			
Daily Charge	63.800	61.394	3.92%
Total Charge (NUoS)			
Daily Charge	186.044	181.114	2.72%
All Energy Charge	1.439	1.150	25.10%
Demand Charge	24.023	22.250	7.97%

3.17.3. Estimated Volumes and Revenues

Table 40: Forecast Installation Numbers, Loads and Revenues for N10

N10	**Period 4**	**Period 3**
Forecast Installation Numbers		
Customer (installation) days in period	26,045	24,861
Forecast Loads		
All Energy	163,282,649	188,953,152
Demand	11,721,896	18,586,022
Expected Revenue		
Daily Charge	48,454	45,026
All Energy	2,349,008	2,172,961
Demand	2,815,946	4,135,390
Total Tariff Revenue	5,213,409	6,353,377

3.17.4. Variations Since Period 3

The rates for this tariff were varied in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.17.5. Future Variations

This tariff is Obsolete as discussed in Sections 6.3 & 6.4 of the NTS. Aurora has introduced a new HV ToU (N10s) tariff, with a long-term aim of replacing this tariff. For more discussion of this, see Sections 6.3 & 6.4 of the NTS.

Network Tariff HV kVA Demand (N10) will be deleted from the suite of tariffs and consequently will not be available after 1 July 2012.

3.18. HV Specified Demand with Time of Use Tariff (N10s)

3.18.1. Terms and Conditions

MSATS Code: AUHVSPECDM.

This Network Tariff is applicable to all qualifying sites that are connected to the Aurora distribution network on or after 1 July 2009. Existing qualifying sites may transfer to this Network tariff on or after 1 July 2009.

A site qualifies for this Network Tariff if:

- connection is made to this site at HV; and
- the expected ATMD of the site is less than 2 MVA.

A site connected to the Aurora distribution network with this Network Tariff is not eligible for any other Network Tariff.

A meter capable of recording “interval data” is required for installations on this tariff.

The Use of System charges applicable for this tariff is composed of the following charging components:

a) DUOS

i) A fixed daily charge; and

ii) An energy-based charge; the rate of the energy charge varies according to the time of day at which energy is consumed, with the periods being as identified in Table 41; and

iii) A demand-based charge calculated according to the method given in the General Terms and Conditions for Network Tariffs for the calculation of charges for Specified Demand tariffs. For the purposes of this calculation, the Excess Demand rate is ten times the Specified Demand rate.

b) TUOS

i) An energy-based charge; the rate of the energy charge varies according to the time of day at which energy is consumed, with the periods being as identified in Table 41.

ii) A demand-based charge calculated according to the method given in the General Terms and Conditions for Network Tariffs for the calculation of charges for Specified Demand tariffs. For the purposes of this calculation, the Excess Demand rate is ten times the Specified Demand rate.

c) Metering

i) A charge for the provision of metering services may apply, depending upon whether or not Aurora is appointed as Metering Provider.

Table 41: Time Periods within Specified Demand Tariffs

Time Period	Summer (1 Oct - 31 Mar)	Winter (1 Apr - 30 Sep)
Week Day (0700 – 2200) (Monday – Friday)	Shoulder	Peak
Weekend Day (0700 – 2200) (Saturday & Sunday)	Off-peak	Shoulder
Any Day (2200 – 0700) (Monday – Sunday)	Off-peak	Off-peak

3.18.2. Rates

Table 42: Proposed Tariff Rates and Charges for N10s

N10s	**Period 4**	**Period 3**	**% Change P4**
DUoS Charge			
Daily Charge	122.244	119.720	2.11%
Peak Energy	0.090	0.085	5.81%
Shoulder Energy	0.072	0.068	5.88%
Off-Peak Energy	0.045	0.042	6.81%
Specified Daily Demand Charge	16.488	15.480	6.51%
Excess Demand Charge	164.883	154.800	6.51%
TUoS Charge			
Peak Energy	1.205	0.951	26.73%
Shoulder Energy	0.961	0.759	26.61%
Off-Peak Energy	0.596	0.470	26.73%
Specified Daily Demand Charge	1.529	1.206	26.78%
Excess Demand Charge	15.290	12.060	26.78%
Meter Charge			
Daily Charge	0.000	0.000	0.000
Total Charge (NUoS)			
Daily Charge	122.244	119.720	2.11%
Peak Energy	1.295	1.036	25.02%
Shoulder Energy	1.033	0.827	24.91%
Off-Peak Energy	0.641	0.512	25.10%
Specified Daily Demand Charge	18.017	16.686	7.98%
Excess Demand Charge	180.172	166.860	7.98%

3.18.3. Estimated Volumes and Revenues

Table 43: Forecast Installation Numbers, Loads and Expected Revenues for N10s

N10s	**Period 4**	**Period 3**
Forecast Installation Numbers		
Customer (installation) days in period	367	1,825
Forecast Loads		
Peak Energy	17,637,712	6,060,023
Shoulder Energy	19,245,134	11,159,798
Off-Peak Energy	26,509,682	14,862,893
Specified Daily Demand Charge	9,156,463	1,820,417
Excess Demand Charge	0	0
Expected Revenue		
Daily Charge	448	2,185
Peak Energy	228,449	62,782
Shoulder Energy	198,802	92,292
Off-Peak Energy	169,796	76,098
Specified Daily Demand Charge	1,649,740	303,755
Excess Demand Charge	0	0
Total Tariff Revenue	2,247,236	537,111

3.18.4. Variations Since Period 3

The rates for this tariff were increased in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.18.5. Future Variations

Aside from variations due to allowable adjustments in AARR and rebalancing between revenues collected from each tariff class and between fixed and variable costs, no changes are planned to this tariff.

3.19. HV Specified Demand, > 2MVA (N15)

MSATS Code AUCHVDM2

3.19.1. Terms and Conditions

This tariff applies to contestable customers, with a demand in excess of 2 MVA, supplied directly from the Aurora distribution network, with no Aurora Network-owned assets beyond the connection point.

The customer must supply its own transformers & switchgear for installations connected on this tariff.

Metering of consumption is at the HV connection point.

3.19.2. Negotiation of "Specified Demand"

Customers on Network Tariff N15 are able to agree with Aurora a "Specified Demand" for their electrical installation.

Once agreed this value is used in the calculation of NUoS charges for the following period of no less than twelve months.

Negotiation of "Specified Demand" for subsequent periods should be completed at least two months prior to the end of the last negotiated period.

Renegotiation of specified demand is limited to one occurrence each twelve months or as otherwise agreed with Aurora.

3.19.3. Rates

Table 44: Proposed Tariff Rates and Charges for N015

N15	**Period 4**	**Period 3**	**% Change P4**
DUoS			
Daily Charge	16.550	16.208	2.11%
Specified Daily Demand Charge	8.228	7.725	6.52%
Excess Demand Charge	41.141	38.625	6.52%
Peak Energy	1.295	1.216	6.52%
Shoulder Energy	0.351	0.329	6.64%
Off-Peak Energy	0.045	0.042	6.81%
Connection			
Specified Demand Charge	0.299	0.280	6.66%
Excess Demand Charge	1.493	1.400	6.66%
Meter Charge (if applicable)			
Daily Charge	0.000	0.000	0.000
Transmission Charge			
Specified Daily Demand Charge	NA	NA	NA
Excess Demand Charge	NA	NA	NA
Peak Energy	NA	NA	NA
Shoulder Energy	NA	NA	NA
Off-Peak Energy	NA	NA	NA

3.19.4. Estimated Volumes and Revenues

Table 45: Forecast Installations, Loads and Revenues for Tariff N15

N15	**Period 4**	**Period 3**
Forecast Installation Numbers		
Customer (installation) days in period	7,337	8,679
Forecast Loads		
Specified Daily Demand Charge	21,333,512	22,494,482
Excess Demand Charge	104,359	24,493
Peak Energy	65,692,572	37,957,798
Shoulder Energy	71,679,496	69,900,954
Off-Peak Energy	98,736,682	93,095,803
DUoS & Connection Expected Revenue		
Daily charge	121,419	140,667
Peak Energy	850,881	461,567
Shoulder Energy	251,483	229,974
Off-Peak Energy	44,295	39,100
Specified Daily Demand Charge	1,819,094	1,800,683
Excess Demand Charge	44,493	9,803
Meter Revenue (if applicable)		
Daily Charge	0	0
Total Tariff Revenue	3,131,666	2,681,795

3.19.5. Variations Since Period 3

The rates for this tariff were varied in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.19.6. Future Variations

Aside from variations due to allowable adjustments in AARR and rebalancing between revenues collected from each tariff class and between fixed and variable costs, no changes are planned to this tariff.

3.20. HV ITC Tariff

Individual Tariff Calculation Customer (ITC) network prices will typically apply to customers with an electrical demand in excess of 2.0 MVA, or where a customer's circumstances in a pricing zone identify the average shared network charge to be meaningless or distorted. Individually calculated customer network charges are determined by modelling the connection point requirements as requested by the customer or their agents.

ITC prices are based on actual Transmission Use of System (TUoS) charges for the relevant transmission connection point, plus charges associated with the actual shared distribution network utilised for the electricity supply, plus connection charges based on the actual connection assets utilised. This provides the greatest cost reflectivity for this type of customer and is feasible since the number of such customers is relatively small.

3.20.1. Terms and Conditions

Terms and conditions for these customers are contained within individually negotiated connection agreements.

3.20.2. Rates

Being negotiated between Aurora and individual customers, these are considered by Aurora to be "Commercial in Confidence". They are supplied to the Regulator in a separate attachment.

3.20.3. Variations

Any variations to customers on this tariff are the subject of individual negotiation.

3.20.4. Future Variations

Any variations to customers on this tariff are the subject of individual negotiation.

3.21. Street Lighting (N20)

3.21.1. Terms and Conditions

This tariff is available to councils and road authorities.

There are no energy charges.

This tariff does not include charges for the installation and/or replacement of lamps. Costs for installation or replacement of lamps are an additional charge. These charges are included in the final street lighting tariff.

3.21.2. Rates

Table 46: Proposed Tariff Rates and Charges for N20

N20	Period 4	Period 3	% Change P4
DUoS Charge			
Demand Charge	0.079	0.074	6.78%
TUoS Charge			
Demand Charge	0.035	0.027	28.14%
Total Charge (NUoS)			
Demand Charge	0.114	0.101	12.49%

3.21.3. Estimated Volumes and Revenues

Table 47: Forecast Installation Numbers and Revenues

N20	Period 4	Period 3
Forecast Installation Numbers		
Forecast total lamp wattage	2,043,933,231	2,024,853,697
Expected Revenue		
Demand charge	2,322,230	2,045,102

Note: Does not include charges for light fitting. These are contained in a separate charge for street lighting.

3.21.4. Variations Since Period 3

The rates for this tariff were varied in line with the strategy presented in Section 5.1 of this Pricing Proposal.

3.21.5. Future Variations

Aside from variations due to allowable adjustments in AARR and rebalancing between revenues collected from each tariff class and between fixed and variable costs, no changes are planned to this tariff.

3.22. Standard Transmission Charges

A number of customers, or groups of customers, may have a specially calculated tariff. As part of this tariff there will be a pass-through of the transmission charges arising from each customer's share of the load on the transmission system. These nodal connection charges are based upon demand, and vary according to the Transend terminal substation to which the customer is connected.

As discussed in Section 4.2 Aurora has estimated that transmission charges will increase by 29.06% for the 20010/11 financial year. Transend will not set charges for the provision of transmission services until 15 May 2010. Aurora has therefore shown the transmission charges that applied for the 2009/10 year for reference only. Aurora will release its 2010/11 transmission prices when they are available from Transend.

Table 48: Schedule of Transmission Charges 2009/10

Connection Site	TNI	Monthly Common Service Charge ($/MVA)	Monthly TUoS Usage Charge ($/MVA)	Monthly Exit Charge ($/MVA)	Total Monthly Charge ($/MVA)	Daily Charge ($/MVA)	Daily Charge (c/kVA) 09/10
Arthurs Lake	TAL2	903.90	1,946.86	2,385.55	6,577.66	216.25	21.6252
Avoca	TAV2	1,195.26	2,155.01	2,372.46	7,496.42	246.46	24.6458
Bridgewater	TBW2	1,065.51	1,303.32	1,137.76	5,087.76	167.27	16.7269
Burnie	TBU3	1,195.26	1,352.88	619.98	4,941.81	162.47	16.2471
Derby	TDE2	828.11	5,032.04	5,242.36	12,331.40	405.42	40.5416
Derwent Bridge	TDB2	556.39	906.08	46,827.85	49,115.97	1,614.77	161.4772
Devonport	TDP2	1,195.26	1,628.17	1,007.40	5,604.53	184.26	18.4259
Electrona	TEL2	1,063.02	2,935.20	978.51	6,554.20	215.48	21.5481
Emu Bay	TEB2	996.05	1,054.10	1,507.05	5,035.28	165.54	16.5543
Kermandie	TKE2	1,195.26	2,853.05	5,225.42	11,047.42	363.20	36.3203
Kingston	TKI2	953.93	1,615.16	788.34	4,773.02	156.92	15.6921
Knights Rd	TKR2	1,195.26	2,189.95	1,622.49	6,781.39	222.95	22.2950
Meadowbank	TMB2	1,076.85	993.27	2,161.18	5,829.29	191.65	19.1648
New Norfolk	TNN2	1,195.26	1,556.96	1,475.05	6,000.96	197.29	19.7292
Newton	TNT2	1,045.85	4,279.66	3,059.67	9,937.17	326.70	32.6702
Palmerston	TPM3	1,303.92	872.13	2,750.83	6,861.81	225.59	22.5594
Port Latta	TPL2	1,124.39	2,539.88	1,628.19	6,960.98	228.85	22.8854

Connection Site	TNI	Monthly Common Service Charge ($/MVA)	Monthly TUoS Usage Charge ($/MVA)	Monthly Exit Charge ($/MVA)	Total Monthly Charge ($/MVA)	Daily Charge ($/MVA)	Daily Charge (c/kVA) 09/10
Queenstown	TQT2	1,195.26	1,902.39	3,781.62	8,652.96	284.48	28.4481
Railton	TRA2	1,106.72	1,151.60	1,014.41	4,915.04	161.59	16.1590
Rosebery	TRB2	956.21	750.56	2,633.94	5,759.66	189.36	18.9359
Savage River	TSR2	909.25	1,722.42	1,441.50	5,422.44	178.27	17.8272
Scottsdale	TSD2	1,195.26	4,267.05	4,617.34	11,853.34	389.70	38.9699
Smithton	TST2	1,145.45	3,499.44	1,068.16	7,412.85	243.71	24.3710
Sorell	TSO2	1,187.82	2,200.36	1,222.24	6,373.08	209.53	20.9526
St Marys	TSM2	1,042.10	2,141.69	2,515.77	7,245.98	238.22	23.8224
Triabunna	TTB2	1,195.26	2,203.56	5,376.08	10,548.60	346.80	34.6803
Tungatinah	TTU2	1,187.71	740.35	19,843.12	23,533.69	773.71	77.3710
Ulverstone	TUL2	1,195.26	1,530.59	909.86	5,409.40	177.84	17.7843
Waddamana	TWA2	573.42	353.96	6,846.73	8,625.03	283.56	28.3562
Wesley Vale	TWV2	682.07	1,098.63	1,650.06	4,442.91	146.07	14.6068
Hobart Virtual	TVN1	1,040.28	1,476.05	827.85	4,887.91	160.70	16.0698
Tamar Virtual	TVN2	1,023.69	985.45	878.65	4,406.88	144.88	14.488

Virtual transmission nodes have been developed for Hobart and Launceston due to the high level of inter-connectability of the transmission connection sites and the regular need to transfer loads within the distribution network.

Hobart (Virtual) is based on the following connection sites: Chapel St, Creek Rd, Lindisfarne, Nth Hobart, Risdon and Rokeby. Launceston (Virtual) is based on the Norwood, Trevallyn, Hadspen and George Town connection sites.

3.23. General Network Terms and Conditions

These General Network Terms and Conditions are applicable to all Network Tariffs.

3.23.1. Times

All times are given as Australian Eastern Standard Time.

3.23.2. Changes of Tariff

Customers seeking tariff reassignment must remain on the reassigned tariff for a minimum twelve (12) month period unless otherwise agreed with Aurora.

3.23.3. Aurora's Obligation to Supply

Under Section 26(2) of the ESI Act, Aurora is not obliged to supply electricity to a customer if:

a) the supply would overload the power system or prejudice in some other way the supply of electricity to other customers; or

b) the supply would result in contravention of the conditions of the electricity entity's licence; or

c) the supply would result in risk of fire or some other risk to life or property; or

d) the supply is or needs to be interrupted –

  i) in an emergency; or

  ii) in circumstances beyond the electricity entity's control; or

  iii) for carrying out work on electricity infrastructure; or

  iv) to comply with a direction to the electricity entity under the ESI Act; or

e) the electricity entity is exempted from the obligation by regulation.

3.23.4. Customers' General Obligations

Aurora is obliged to place the following conditions upon customers under the TEC.

3.23.4.1. Use of Electricity

A Customer must not allow a supply of electricity to its electrical installation to be used other than at the Customer's premises nor will the Customer supply electricity so supplied to any other person without the prior approval of Aurora. [TEC 8.6.2(a)(1)]

A Customer must not take electricity supplied to another Customer's electrical installation by Aurora at the Customer's premises. [TEC 8.6.2(a)(8)]

3.23.4.2. Maintenance of Customers' Installations

A Customer must at its own expense, maintain the Customer's electrical installation in a safe condition to the satisfaction of its Distribution Network Service Provider [Aurora] or other relevant authority. [TEC 8.6.2(a)(5)]

3.23.4.3. Operation of Customers' Installation

A Customer must ensure that the Customer's electrical installation and any equipment within it (including protective equipment) are adequate, and effectively co-ordinated at all times with the electrical characteristics of Aurora's distribution system. [TEC 8.6.2(a)(6)]

A Customer must use the electricity supplied to its electrical installation in a manner, which in the opinion of Aurora, does not interfere with the supply of electricity to other Customers' electrical installations or cause damage or interference to any third party. [TEC 8.6.2(a)(7)]

3.23.4.4. Protection of Aurora Assets

A Customer must not interfere or allow interference with any equipment of its Distribution Network Service Provider [Aurora] which is on the Customer's premises except as may be permitted by law. [TEC 8.6.2(a)(2)]

A Customer must provide and maintain on the Customer's premises any reasonable or agreed facility required by Aurora to protect any equipment of the Distribution Network Service Provider [Aurora]. [TEC 8.6.2(a)(4)]

3.23.4.5. Access

A Customer must at all times, make available to Aurora's officers or agents, together with their equipment, a safe, convenient and unhindered access to the equipment of the Distribution Network Service Provider [Aurora] on the Customer's premises for any purposes associated with the supply, metering or billing of electricity or the inspection and/or testing of the Customer's electrical installation, provided that official identification is produced by the officers or agents on request. The Customer must provide protective equipment to officers or agents of Aurora if that is necessary to ensure safe access to the Customer's premises. [TEC 8.6.2(a)(3)]

3.23.4.6. Compulsory Provision of Land

A Customer must if, in respect of an electrical installation, it has a maximum demand over 100 kVA must, if Aurora is unable to continue to satisfy that maximum demand without installing a new substation, sell or lease to Aurora the land upon which a new substation can be installed by Aurora in order to allow Aurora to satisfy that maximum demand. [TEC 8.6.2(b)]

3.23.4.7. Power Factor

A Customer must (unless otherwise agreed with its Distribution Network Service Provider) at all times keep the power factor of its electrical installation within the relevant range set out in Table 49. [TEC 8.6.3(a)]

Table 49: Power Factor Ranges

Supply Voltage (kV)	Power Factor range for Customer maximum demand and voltage					
	Up to 100 kVA		Over 100 kVA, less than 2 MVA		Over 2 MVA	
	Minimum Lagging	Minimum Leading	Minimum Lagging	Minimum Leading	Minimum Lagging	Minimum Leading
<1	0.75	0.80	0.80	0.80	0.85	0.85
1 - 6.6	0.75	0.80	0.80	0.80	0.90	0.90
6.6, 11, 22	0.80	0.80	0.85	0.85	0.90	0.90
33, 44, 66	0.85	0.85	0.90	0.90	0.95	0.95

3.23.4.8. Voltage Fluctuations

A Customer must ensure that the customer's equipment does not cause voltage fluctuations at the point of common coupling greater than the levels specified in AS/NZ 61000.3.5:1998 and AS/NZ 61000.3.7:2001 as appropriate. [TEC 8.6.9]

If two or more Customers' electrical installations are connected at the same point of common coupling, the maximum permissible contribution to voltage fluctuations allowable from each Customer is to be determined in proportion to their respective maximum demand, unless otherwise agreed. [TEC 8.6.9]

3.23.4.9. Provision of Planning Information

[TEC 8.8(a)] A Customer must supply, if requested, to Aurora or the Electricity Retailer as the case may be, details of loads connected or planned to be connected to Aurora's distribution system which Aurora requires for the purpose of planning its distribution system, including:

(1) the location of the load in the distribution system;

(2) existing loads;

(3) existing load profile;

(4) changes in load scheduling;

(5) planned outages;

(6) forecasts of load growth;

(7) anticipated new loads;

(8) anticipated redundant loads; and

(9) the nature of any disturbing loads.

3.23.4.10. Vegetation Management

A Customer must, at its own expense, maintain safe clearances between vegetation on the Customer's property and electrical infrastructure providing supply to the Customer's electrical installation. [TEC 8.6.2(a)(9)]

3.23.5. Fallback

In the event that a customer is moved onto a Fallback Contract, the Network Tariff(s) for that customer's installation(s) affected by the move remain(s) unchanged.

3.24. Demand Tariffs

3.24.1. Reassignment of Network Tariffs due to Increases in Electrical Demand

Where a customer requires a change in Network Tariff due to an increase in electrical demand at a connection point, the customer must submit a written request to Aurora Energy.

The increased level of electrical demand shall apply from the requested date or as near as possible thereafter, subject to any required works being completed by Aurora Energy.

Exceptions will only be made at Aurora Network's discretion where it can be demonstrated that to not do so would result in unreasonable penalties or impose hardship on the customer.

Note: this condition prevents customers from changing tariffs to take advantage of seasonal variations in prices according to their individual load; thereby bypassing payment that reflects use of the distribution network over a full twelve (12) month cycle.

3.24.2. Reassignment of Network Tariffs due to Temporary Increases in Maximum Demand

Temporary increases in electrical demand will:

- be subject to negotiation and approval by Aurora Energy;
- be defined in terms of "additional demand" for a specific period and charged at an agreed Demand Charge rate;
- apply for one full billing period, except in the case of commissioning of new plant, in which case the duration of the temporary increase may be extended for the duration of the commissioning period; and
- be limited to one occurrence each twelve months or as otherwise agreed with Aurora Energy.

3.24.3. Reassignment of Network Tariffs due to Reductions in Maximum Demand

Where a customer requires a change in Network Tariff due to a reduction in electrical demand at their connection point, the customer must provide six months written advice to Aurora Energy detailing their new requirement.

Aurora Energy will notify the customer in writing within sixty days of receipt of the written advice, advising the revised NUoS charges and also any costs associated with the relocation of Aurora's assets at their site.

Following the installation by a customer of load management equipment approved by Aurora Energy or the implementation of a demand management initiative approved by Aurora Energy, the six month notice period referred to above may be reduced at the discretion of Aurora Energy.

Customers seeking tariff reassignment must remain on the reassigned tariff for a minimum twelve (12) month period.

Exceptions will only be made at Aurora Network's discretion where it can be demonstrated that to not do so would result in unreasonable penalties or impose hardship on the customer.

Note: this condition prevents customers from changing tariffs to take advantage of seasonal variations in prices according to their individual load; thereby bypassing payment that reflects use of the distribution network over a full twelve (12) month cycle.

3.24.4. Calculation of Maximum Demand

Any tariff charges based upon the maximum demand of an installation are calculated using the maximum demand for the installation during the billing period. The maximum demand of an installation during a billing period is taken to be the largest value of the electrical demand for that installation during that billing period. The electrical demand of an installation for a "Demand Integration Period" is taken to be the energy consumption of that installation during the "Demand Integration Period" divided by the length of the "Demand Integration Period" measured in hours. Currently, the Demand Integration Period is 15 minutes.

3.24.5. Calculation of NUoS Charges for Specified Demand Tariffs

In this section, "Nominated Demand" means the value of electrical demand of the site to which the Specified Demand Network Tariff applies as nominated by the operator of that site to Aurora.

3.24.5.1. Network Tariff N15

The demand-based charges for an installation on the Network Tariff N15 would be calculated monthly as follows:

a) the monthly demand-based charge is the sum of the daily demand-based charges for the month;

b) the daily demand-based charges are:

   (i) if any daily ATMD in the month is less than or equal to 100% of the Nominated Demand, the demand charge for the day will be equal to the specified demand multiplied by the specified demand rate; or

   (ii) if any daily maximum demand in the month is greater than the Nominated Demand, the daily demand charge will be the sum of:

- the specified demand multiplied by the specified demand rate; and
- the difference between the maximum demand and the specified demand multiplied by the excess demand rate;

(iii) the excess demand rate is five times the specified demand rate.

3.24.5.2. Network Tariffs other than N15

The demand-based charges for an installation on a Specified Demand Network Tariff other than N15 would be calculated monthly as follows:

a) the monthly demand-based charge is the sum of the daily demand-based charges for the month;

b) the daily demand-based charges are:

(i) if any daily ATMD in the month is less than or equal to 100% of the Nominated Demand, the demand charge for the day will be equal to the specified demand multiplied by the specified demand rate; or

(ii) if the daily ATMD is greater than the Nominated Demand, but not greater than 120% of the Nominated Demand, then the demand charge for the day will be the maximum demand multiplied by the specified demand rate; or

(iii) if any daily maximum demand in the month is greater than the Nominated Demand by 120%, the daily demand charge will be the sum of:

- 120% of the specified demand multiplied by the specified demand rate; and
- the difference between the maximum demand and 120% of the specified demand multiplied by the excess demand rate;

(iv) the excess demand rate is ten times the specified demand rate.

4. Adjustment Variables

This section is to address:

Guideline 2.3(d)(6):

> "A Network Tariff Pricing Proposal must…provide details of adjustment variables, including CPI, pass-through and other adjustments permissible under the 2007 Determination and transmission charges attributable to distribution connected customers for the period and an explanation of how each Network Tariff will be affected by the impact of the adjustment or adjustments…"

Guideline 2.3(d)(9):

> "A Network Tariff Pricing Proposal must…describe the nature and extent of and proposed changes from the previous period and demonstrate that the changes comply with these Guideline and the 2007 Determination;"

The following sections detail the changes to the adjustment variables allowed in the 2007 Determination.

4.1. AARR Calculation Equation Variables

4.1.1. CPI Adjustments

The Regulator permits Aurora's AARR to be indexed according to CPI in two ways: the inflation of the forecast maximum revenues, which were given in July 2006 dollars, by a Prescribed Inflationary Factor; and the inflation of adjustments from previous periods.

4.1.2. Prescribed Inflationary Factor

The value for the Prescribed Inflationary Factor is given in Section 3 of the Determination.

The CPI value for the quarter ending on 30 June 2006 was 154.3.

The CPI value for the quarter ending on 31 December 2009 was 169.5.

4.1.3. Inflation from Previous Periods

The Determination defines the quantity CPI_y as "the CPI for the quarter ending 6 months prior to the commencement of the period in question. Thus CPI_4 will be the CPI for the December quarter 2009."

In calculating the AARR, the determination prescribes the use of the values CPI_y, CPI_{y-1}, CPI_{y-2} and CPI_{y-3}. For this Period 4, therefore, we need values for CPI_3, CPI_2, CPI_1 and CPI_0. Using the definition:

> CPI4 will be the CPI for the December quarter of 2009, since P_4 begins on 1 July 2010;
>
> CPI_3 will be the CPI for the December quarter of 2008, since P_3 begins on 1 July 2009;
>
> CPI_2 will be the CPI for the December quarter of 2007, since P2 begins on 1 July 2008;
>
> CPI_1 will be the CPI for the June quarter of 2007, since P_1 begins on 1 January 2008; and

CPI_0 will be the CPI for the June quarter of 2006, since P_0 begins on 1 January 2007.

Thus,

CPI_4 is 169.5;

CPI_3 is 166.0;

CPI_2 is 160.1;

CPI_1 is 157.5; and

CPI_0 is 154.3.

4.1.4. Electrical Safety Inspection Service Charge Adjustment

This is the allowable variation between the actual electrical safety inspection service charge for Period 3 and the forecast charge for Period 3. The actual electrical safety inspection service charge is as determined by the Minister, and published in the Gazette, in accordance with section 121B of the ESI Act.

The calculation, presented in Section 8, provides the allowable variation to be, $0.167m.

4.1.5. National Energy Market Charge

This is the allowable variation between the National Energy Market charge for Period 3 and the forecast charge for Period 3. The actual National Energy Market charge is as determined by the Minister, and published in the Gazette, in accordance with section 121 of the ESI Act.

The calculation, presented in Section 8, provides the allowable variation to be, -$0.022m.

4.1.6. Trunk Mobile Radio Allowance

This is the allowable variation between the amount provided in the AARR and the actual cost of participation in the State Government's Trunk Mobile Radio Network.

The calculation, presented in Section 8, provides the allowable variation to be, -$0.541m.

4.1.7. GSL Scheme Single Event Cap

The 2007 Determination provided a mechanism to recognise the effects on Aurora's manpower resources of a large event that causes widespread outages. The mechanism allows Aurora to recover half of the value of extended duration GSL payments made to customers that experienced an outage of duration between the normal codified standard and a revised threshold that takes into account the number of customers affected.

The calculation, presented in Section 8, provides the allowable variation to be $0.309m.

4.1.8. *Under/Over Recovery Adjustment*

The 2007 Determination allows Aurora to adjust its revenues to account for over- or under-recovery of revenues in a previous year due to a difference between the forecast and actual customer base, the latter being a function of the number of installations and the expected loads of individual tariff classes.

The calculation, presented in Section 8, provides the allowable variation to be -$5.829m.

4.1.9. *NEM Costs*

This adjustment is to allow for the difference between allowed forecast costs for participation in the NEM, excluding those cost attributable to Full Retail Contestability.

The calculation, presented in Section 8, provides the allowable variation to be $3.358m.

4.1.10. *FRC Costs*

This allowance is to provide for the recovery of costs associated with preparations by Aurora for operating under Full Retail Contestability in Tasmania.

The calculation, presented in Section 8, provides the allowable variation to be zero.

4.1.11. *Allowable Tax Events*

This adjustment to provide for the pass-through of costs associated with an allowable tax event as consistent with Regulation 31(4) of the Price Control Regulations.

During Period 3 there were no such allowable tax events, so the adjustment is zero.

4.1.12. *Approved Increased Safety / Environmental Compliance Costs*

This adjustment to provide for the pass-through of costs associated with a change in safety or environmental legislation.

During Period 3 there were no such changes in legislation, so the adjustment is zero.

4.1.13. *Capital Contributions Policy Change Adjustment*

This adjustment is to compensate for the effects upon AARR of a change in Aurora's Capital Contributions Policy.

During Period 3 there was no change to Aurora's Capital Contributions Policy, so the value of this adjustment is zero.

4.1.14. *GSL Scheme Cumulative Payments Cap*

The 2007 Determination allows Aurora to limit its exposure under the GSL scheme by providing an adjustment to recover the value of "excessive" GSL payments.

The actual payments for Period 3 are not available until the Regulated accounts covering Period 3 are completed and audited. The adjustment for GSL payment related to Period 3 is to be held over until Period 4.

For Period 4, $GSLcap_2$ is zero.

4.1.15. Adjustment from Previous Determination

The Regulator, in the AARR calculation methodology, provides an adjustment variable to allow for revenue adjustments resulting from the 2003 Determination.

The calculation, presented in Section 8, provides the allowable variation to be zero.

4.1.16. Banking

The Regulator, in the AARR calculation, provides an adjustment variable to be used to assist in smoothing price fluctuations.

Aurora intends, subject to approval by the Regulator, to use the full capacity of this adjustment variable in Period 4, making the adjustment $4.607m.

4.2. Transmission Costs

The delivery of electricity from generation to final consumer involves two levels of network services, distribution and transmission. Transend is the monopoly provider of transmission network services in Tasmania, holding a transmission licence in accordance with the ESI Act. Transend's revenues are regulated by the AER, with the AER's transmission determination setting the maximum revenues that Transend may earn for the provision of transmission services. Aurora collects revenues on behalf of Transend; these are included as a component of Aurora's charges for the provision of distribution services.

Aurora anticipates the 20010/11 Transend charge to be around $116 million. By way of comparison, the amount required for the provision of transmission services to customers on the Aurora distribution network during the 2009/10 financial year was $90 million.

4.3. Metering Costs

The Regulator has declared metering services independently of distribution services for the 2008-2012 regulatory period, choosing to regulate metering services by application of a price cap method.

To comply with the 2007 Determination and recover the correct revenue for the provision of distribution metering services, Aurora has applied an average fixed daily metering charge to each Network Tariff.

This charge is calculated as described in the Network Tariff Strategy (Section 5.4.3).

The charge is incorporated into the individual tariffs, and shown in Section 2

4.4. Effects of Adjustment Variables on Network Tariffs

4.4.1. AARR Adjustment Variables

The maximum allowable revenue that may be recovered by Aurora is the sum of the AARR and the adjusted metering and transmission cost pass throughs. The AARR adjustment variables increase or decrease the total amount of revenue that may be recovered. The effects of varying the maximum allowable revenue are, therefore, passed through to all installations on a pro rata basis through the tariffs.

4.4.2. Transmission Charge Variations

Transmission charges are considered as a direct pass-through. Initially, The allocation of TUoS is by reference to the DCoS model so that the transmission charges borne by a tariff customer class is proportional to the fraction of the distribution network cost attributable to that class (see NTS Section 5.4.2). So, any variation in transmission charges is passed through to all installations on a pro rata basis through the tariffs.

4.4.3. Metering Charges Variations

Metering charges are allocated to tariff customer groups based upon the usage of particular meter types by those tariff customer groups, so any variation in metering charges will be allocated pro rata on that basis.

4.5. Effects of Decreasing Consumption on Network Tariffs

The large price increases experienced by customers during Periods 1 and 2 of the current Regulatory Period; and milder than anticipated winter weather patterns have resulted in reduction in energy consumption for a number of customers.

This reduction in energy consumption has meant that Aurora has not recovered its allowable revenue for Period 3 by approximately $3m.

Given the low consumption again experienced in Period 3, Aurora has been conservative with its energy and customer forecasts for Period 4.

This lower than anticipated 'growth' means that Aurora must increase prices by more than would have been anticipated to ensure an appropriate recovery of its allowable revenue for Period 4.

4.6. Effects of Increasing AARR on Network Tariffs

Several factors, discussed above, have an effect on AARR, which leads through to variations in tariff rates. A further factor in tariff increases is in the actual variation of AARR between periods.

The MAR for Period 3 was $227.893 million. For Period 4, MAR has been calculated to be $232.403 million. Period 4 MAR has increased by 1.98%, over that of Period 3. The customer base, on the other hand, has been estimated to increase by less than 1%.

This means that revenues collected from tariff classes have increased by an average of 9%, but this increase is spread over only 1% more customers. Tariff rates must, therefore, increase by more than CPI, with the actual rate for a tariff varying according to the characteristics of the customers being served by that tariff.

5. Methodologies

5.1. *Rebalancing of Revenues*

Due to the carry forward of adjustments from Period 3 to Period 4, Aurora's total revenue increased by approximately 9.26% between the two periods, while its customer base and load is expected to increase by only around 1% (Section 9.1).

To meet this increase in revenue, Aurora proposes the following general strategy:

- All customers will see an increase of around CPI in the daily charge component of their Network Tariff;
- All customers will see an increase of around 4% in the Metering component of their Network Tariff;
- DUoS and TUoS components of all tariffs will be rebalanced to ensure an appropriate recovery of these components. This will mean that whilst total DUoS revenue will increase by around 6.5% and total TUoS revenue by around 29%, individual DUoS and TUoS tariff components will vary by differing amounts to the general 6.5% and 29% increases.
- Residential and business customers will see larger increases in the remaining energy block component of tariffs as the incentives to give discounts for larger consumption are unwound as part of demand management strategies.
- Customers on Nursing Home tariff N02a will receive a discounted energy rate in line with the discussion in Section 6.6 of the NTS;
- Customers on curtilage tariff N02b will receive a discounted DUoS daily charge in line with the discussion in Section 6.7 of the NTS;
- Rebalancing to ensure appropriate revenues will be applied as described in Section 5.3.3 of the NTS to "fine tune" the revenue recovery.

5.2. *Reallocation between Fixed and Variable Costs*

There has been a change in the principles of allocation between fixed and variable costs. Aurora is cognisant of the costs that are borne by small consumption customers and has therefore chosen to increase most fixed charges by CPI only. This decision will mean that a rebalance between fixed and variable charges will occur, as variable charges will increase by more than CPI to ensure an appropriate revenue recovery.

5.3. Rebalancing of TUoS and DUoS Revenues

Whilst Aurora's tariffs in Period 3 have resulted in an under recovery of total revenue, the individual Period 3 tariff components have resulted in an over-recovery of TUoS revenues and an under-recovery of DUoS revenues.

In Period 4 Aurora has been able to forecast its DUoS and TUoS components to achieve the desired outcome, not only to recover the total allowable revenue, but the TUoS and DUoS components of that revenue also match the expected charges from Transend and the AARR allowable to Aurora.

6. Compliance

This section is to address Guideline 2.3(d)(8): "A Network Tariff Pricing Proposal must…demonstrate compliance with the 2007 Determination, including demonstrating that the expected revenue from the distribution Network Tariffs does not exceed the AARR for the specified period, these Guideline and the Network Tariff Strategy;

6.1. Reconciliation of Tariff Revenue with AARR

Table 50: Reconciliation of Tariff Revenue with AARR

Revenue Reconciliation	Expected Revenue
Revenue	
Total Revenue from Tariffs N01 to N15	$349,377,423
Total Revenue from Tariff N20 (streetlight DUoS)	$2,322,230
Estimated TUoS pass through to Tariff N15	$4,398,019
DUoS Revenue from Individual Tariff Customers	$1,499,388
TUoS Revenue from Individual Tariff Customers	$4,180,466
Total Revenue	**$361,777,525**
Less adjustments	
TUoS charge	
Forecast total TUoS charge for period	$116,449,577
Metering Revenue	
Revenue included in tariffs	$12,990,061
Total Adjustments	**$129,439,638**
Net revenue after revenue adjustments	**$232,337,888**
AARR allowance from 2007 Determination Table 1	$209,697,000
2007 Determination Adjustment	$2,048,842
CPI adjustment to revenue allowance	$20,657,000
Total revenue allowance (excluding meters)	**$232,402,842**

6.2. Compliance with the Guideline

This section is to demonstrate the compliance of the Period 4 Pricing Proposal with the Guideline.

> Guideline 2.3 (a) (5): Aurora must…submit to the Regulator, at least 2 months before the commencement of Period 3 and each subsequent period of the Determination, a further Pricing Proposal (an 'Annual Pricing Proposal') for the relevant period.

The Pricing Proposal for Period 4 must be submitted to the Regulator before the 30th April, 2009.

> Guideline 2.3 (d) (1): A Network Tariff Pricing Proposal must…set out the proposed Network Tariffs that are to apply for the relevant period…

The proposed Network Tariffs for Period 4 are set out by tariff class in Section 3 of this Pricing Proposal.

> Guideline 2.3 (d) (2): A Network Tariff Pricing Proposal must…set out, for each proposed Network Tariff, the terms and conditions and the charging parameters and the elements of service to which each charging parameter relates…

The terms and conditions, the charging parameters and the elements of service to which each charging parameter relates are set out by tariff class in Section 3 of this Pricing Proposal.

> Guideline 2.3 (d) (3): A Network Tariff Pricing Proposal must…detail the bona fide forecast installation numbers and loads and the basis of that forecast for each proposed Network Tariff used in developing the Network Tariff Pricing Proposal;

The bona fide forecast installation numbers and loads are presented by tariff class in Section 3 of this Pricing Proposal.

The bases of the bona fide forecast installation numbers and loads are taken from data obtained from the Aurora's distribution billing system. Overall loads and installation numbers are anticipated to increase by less than 1% between Periods 3 and 4. This is in line with the most recent 10 year distribution load forecast.

> Guideline 2.3 (d) (4): A Network Tariff Pricing Proposal must…set out, for each proposed Network Tariff, the expected revenue for that Network Tariff for the relevant regulatory period and also for the current regulatory period…

The expected revenues for Period 4 and the expected Revenues for Period 2 for each proposed Network tariff are presented by tariff class in Section 3 of this Pricing Proposal.

> Guideline 2.3 (d) (5): A Network Tariff Pricing Proposal must…detail any proposed amendments, variations or adjustments to the Network Tariff proposed, the justification for the proposed amendments, variations or adjustments and whether these amendments, variations or adjustments are consistent with the Network Tariff Strategy…

Details of any proposed amendments, variations or adjustments to the Network Tariff proposed, the justification for the proposed amendments, variations or adjustments and whether these amendments, variations or adjustments are consistent with the Network Tariff Strategy are presented by tariff in Section 3 of this Pricing Proposal.

> Guideline 2.3 (d) (6): A Network Tariff Pricing Proposal must…provide details of adjustment variables, including CPI, pass-through and other adjustments permissible under the 2007 Determination and transmission charges attributable to distribution connected customers for the period and an explanation of how each Network Tariff will be affected by the impact of the adjustment or adjustments.

Details of adjustment variables and explanations of how each tariff will be affected by these changes are presented in Section 4.

> Guideline 2.3 (d) (7): A Network Tariff Pricing Proposal must…set out the nature of any proposed variation or adjustment to the Network Tariff that could occur during the subsequent periods and the basis on which it could occur…

The nature of any proposed variations or adjustments to Network Tariffs that could occur during subsequent periods and the basis on which they could occur are presented by tariff class in Section 3 of this Pricing Proposal.

> Guideline 2.3 (d) (8): A Network Tariff Pricing Proposal must…demonstrate compliance with the 2007 Determination, including demonstrating that the expected revenue from the distribution Network Tariffs does not exceed the AARR for the specified period, these Guideline and the Network Tariff Strategy…

Demonstration of compliance with the 2007 Determination, including demonstration that the expected revenue from the distribution Network Tariffs does not exceed the AARR for the specified period, the Guideline and the Network Tariff Strategy is presented in Section 6.1 of this Pricing Proposal.

> Guideline 2.3 (d) (9): A Network Tariff Pricing Proposal must…describe the nature and extent of and proposed changes from the previous period and demonstrate that the changes comply with these Guideline and the 2007 Determination…

The nature and extent of proposed changes from the previous period and demonstrations that the changes comply with these Guideline and the 2007 Determination are presented by tariff class in Section 3 of this Pricing Proposal.

> Guideline 2.3 (d) (10): A Network Tariff Pricing Proposal must…demonstrate the impact on typical customers…

The impact of the proposed Network tariffs upon typical customers is presented in Section 7 of this Pricing Proposal.

> Guideline 2.3 (d) (11): A Network Tariff Pricing Proposal must…be accompanied by an internal audit certificate and certified as correct by the Chairman and one other Director of Aurora.

The internal audit certificate and certification of correctness are attached at Attachment A to this Pricing Proposal.

6.3. Compliance with the Network Tariff Strategy

The compliance of aspects of this Pricing Proposal with the NTS is addressed in the sections that deal with those aspects.

6.4. Compliance with the 2007 Determination

6.4.1. "Postage Stamp" Pricing

Pricing Principle (a) of the 2007 Determination requires that, "Network Tariffs for small customers belonging to a particular class are to be uniform, regardless of where in mainland Tasmania the customer is supplied with electricity".

The Aurora suite of tariffs for small customers is applicable irrespective of installation location.

6.4.2. Bounded Revenues

Pricing Principle (a) of the 2007 Determination requires that:

> For each Network Tariff class, the revenue expected to be recovered should lie on or between:
>
> (1) an upper bound representing the stand alone cost of serving the customers who belong to that class; and
>
> (2) a lower bound representing the avoidable cost of not serving those customers.

Using the methodology described in Section 5.1 of the NTS, Aurora has calculated the relevant upper and lower bounds for each Network Tariff class. These, and the revenue recoverable from each Network Tariff class, are presented in Table 51.

Table 51: Tariff Class Revenues, Stand Alone Costs & Avoidable Costs

Tariff Class	**Stand-Alone Cost ($ million)**	**Expected Revenue ($ million)**	**Avoidable Cost ($ million)**
N01 General Network	318.07	117.20	8.70
N02 General Network - Business	260.53	91.73	2.21
N02B - General Network - Business less curtilage	260.53	3.71	0.00
N02A General Network - Business Nursing Homes	260.53	2.73	0.00
N03 LV Metered Demand (kW)	224.99	4.67	0.26
N05 Uncontrolled Heating	230.09	39.03	0.00
N06 Controlled Heating	218.40	2.80	0.00
N06A Controlled Heating - (Night)	218.40	0.00	0.00
N07 Small LV unmetered	216.98	1.22	0.01
N08 LV Irrigation, Day/Night	220.14	8.37	0.08
N08A LV Irrigation, Day/Night, ToU Energy	220.14	0.53	0.08
N09 LV Metered Demand (kVA)	228.86	31.75	0.30
N13 LV PAYG	242.81	31.41	1.95
N13R LV Residential, ToU Energy	242.81	2.14	1.95
N13B LV Commercial, ToU Energy	242.81	1.33	1.95
N10 HV Metered Demand (kVA)	222.25	5.21	0.16
N10S HV Specified Demand (kVA), ToU Energy	222.25	2.25	0.16
N11 HV Metered Demand (kW)	218.27	0.16	0.06
N15 HV>2MVA Specified Demand	217.22	3.13	0.01
N20 Streetlight	218.13	2.32	0.00

6.4.3. Long Run Marginal Costs

Pricing Principle (c)(1) of the 2007 Determination requires that, "A Network Tariff, and if it consists of 2 or more charging parameters each charging parameter for a tariff class…must take into account the long run marginal cost for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates…"

Aurora believes that it has set its Network Tariffs to achieve compliance with this requirement. Refer to Section 9.3.1 of the NTS for discussion of this.

7. Typical Customer Effects

This section is to address Guideline 2.3(d)(10): "A Network Tariff Pricing Proposal must…demonstrate the impact on typical customers; and"

7.1. Estimated Changes to Network Tariff Rates Between Period 3 and Period 4

Previously Aurora presented a typical customer analysis based upon retail tariffs. Bearing in mind that Aurora as a DNSP has little control over how retailers package their tariffs, any such analysis was purely speculatory in nature and final retail outcomes did not match distribution predictions. Aurora has therefore produced a typical customer analysis that provides price impacts for the 'network' component of tariffs only and utilises load predictions for the equivalent retail tariffs.

7.1.1. Method

Historical load distributions by common tariff mix were obtained from Aurora Retail.

The Aurora Network published tariff rates for Period 3 were obtained.

The proposed Period 4 Aurora Network tariffs were included.

The Period 3 and Period 4 Aurora Network tariffs were applied to the historical load distributions.

The results are presented in the following sections

7.1.2. Notes

- The estimated tariffs exclude GST.
- In line with NEM metering convention, consumption is metered on a daily basis. Accordingly, the consumption thresholds in the tariffs, while presented on a quarterly basis, are applied on a pro rata daily basis. The pro rata daily threshold is given by the equation

Pro rata Daily Consumption Threshold = 4 × Quarterly Consumption Threshold ÷ 365.

7.2. *Typical Customer Analysis Results – Estimated Network Outcomes*

7.2.1. *LV General Network – Residential (N01) – this is equivalent to Aurora Retail tariff 31*

N01		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	135	9.528	12.86	10.980	14.82	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
Total	635		105.37		114.72	8.9%
(1st Quartile)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	202	10.587	21.39	11.870	23.98	12.1%
Next 1,000kWh per Quarter (c/kWh)	0	9.528		10.980		
Remaining Consumption (c/kWh)	0	8.999		10.683		
Total	202		60.96		64.53	5.9%
3rd Quartile						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	768	9.528	73.18	10.980	84.33	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
Total	1,268		165.68		184.23	11.2%

7.2.2. *LV General Network – Residential (N01) and LV uncontrolled Energy (N05) – this is equivalent to Aurora Retail tariffs 31 and 41*

N01 & N05		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	558	9.528	53.17	10.980	61.27	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	779	3.094	24.10	3.650	28.43	18.0%
Total			179.96		200.15	11.2%
1st Quartile						
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	146	9.528	13.91	10.980	16.03	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	567	3.094	17.54	3.650	20.69	18.0%
Total			134.15		147.17	9.7%

3rd Quartile						
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	1,000	9.528	95.28	10.980	109.80	15.2%
Remaining Consumption (c/kWh)	49	8.999	4.41	10.683	5.23	18.7%
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	1,077	3.094	33.32	3.650	39.31	18.0%
Total			235.70		264.79	12.3%

7.2.3. LV General Network – Residential (N01) and LV uncontrolled Energy (N05) – this is equivalent to Aurora Retail tariffs 31 and 42

Network Tariffs N01, N05		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	538	9.528	51.26	10.980	59.07	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	1,710	3.094	52.91	3.650	62.41	18.0%
Total			206.86		231.93	12.1%
1st Quartile						
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	238	9.528	22.68	10.980	26.13	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	1,140	3.094	35.27	3.650	41.61	18.0%
Total			160.64		178.19	10.9%

3rd Quartile						
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	931	9.528	88.71	10.980	102.22	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	2,383	3.094	73.73	3.650	86.97	18.0%
Total			265.13		299.65	13.0%

7.2.4. *LV General Network – Residential (N01), LV Uncontrolled Energy (N05) and LV Controlled Heating (N06) – this is equivalent to Aurora Retail tariffs 31, 41 and 61/62*

Network Tariffs N01, N05, N06		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	635	9.528	60.50	10.980	69.72	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	778	3.094	24.07	3.650	28.39	18.0%
(N06)						
Daily Charge (c/day)	91	14.845	13.51	15.313	13.94	3.2%
All Energy Charge (c/kWh)	984	0.837	8.24	0.990	9.74	18.3%
Total			209.01		232.25	11.1%
1st Quartile						
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	360	9.528	34.30	10.980	39.53	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	681	3.094	21.07	3.650	24.85	18.0%
(N06)						
Daily Charge (c/day)	91	14.845	13.51	15.313	13.94	3.2%
All Energy Charge (c/kWh)	522	0.837	4.37	0.990	5.17	18.3%
Total			175.94		193.94	10.2%

Network Tariffs N01, N05, N06		Period 3 2009/10		P4 2010/11		
3rd Quartile	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	1,000	9.528	69.17	10.980	79.72	15.2%
Remaining Consumption (c/kWh)	66	8.999		10.683		
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	961	3.094	44.09	3.650	52.01	18.0%
(N06)						
Daily Charge (c/day)	91	14.845	13.51	15.313	13.94	3.2%
All Energy Charge (c/kWh)	1,530	0.837	7.62	0.990	9.01	18.3%
Total			237.08		265.12	11.8%

7.2.5. *LV General Network – Residential (N01), LV Uncontrolled Energy (N05) and LV Controlled Heating (N06) – this is equivalent to Aurora Retail tariffs 31, 42 and 61/62*

Network Tariffs N01, N05, N06		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	726	9.528	69.17	10.980	79.72	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	1,425	3.094	44.09	3.650	52.01	18.0%
(N06)						
Daily Charge (c/day)	91	14.845	13.51	15.313	13.94	3.2%
All Energy Charge (c/kWh)	910	0.837	7.62	0.990	9.01	18.3%
Total			237.08		265.12	11.8%
1st Quartile						
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	424	9.528	40.40	10.980	46.56	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	1,019	3.094	31.53	3.650	37.19	18.0%
(N06)						
Daily Charge (c/day)	91	14.845	13.51	15.313	13.94	3.2%
All Energy Charge (c/kWh)	644	0.837	5.39	0.990	6.38	18.3%
Total			193.52		214.51	10.8%

Network Tariffs N01, N05, N06		**Period 3 2009/10**		**P4 2010/11**		
3rd Quartile	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	1,000	9.528	95.28	10.980	109.80	15.2%
Remaining Consumption (c/kWh)	138	8.999	12.42	10.683	14.74	18.7%
(N05)						
Daily Charge (c/day)	91	11.195	10.19	11.590	10.55	3.5%
All Energy Charge (c/kWh)	1,849	3.094	57.21	3.650	67.48	18.0%
(N06)						
Daily Charge (c/day)	91	14.845	13.51	15.313	13.94	3.2%
All Energy Charge (c/kWh)	1,288	0.837	10.78	0.990	12.76	18.3%
Total			291.89		329.17	12.8%

7.2.6. LV General Network – Residential (N01) and LV Controlled Heating (N06) – this is equivalent to Aurora Retail tariffs 31 and 61/62

Network Tariffs N01, N06		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	508	9.528	48.40	10.980	55.78	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N06)						
Daily Charge (c/day)	91	14.845	13.51	15.313	13.94	3.2%
All Energy Charge (c/kWh)	1,110	0.837	9.29	0.990	10.99	18.3%
Total			163.71		180.61	10.3%
1st Quartile						
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	258	9.528	24.58	10.980	28.33	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N06)						
Daily Charge (c/day)	91	14.845	13.51	15.313	13.94	3.2%
All Energy Charge (c/kWh)	642	0.837	5.37	0.990	6.36	18.3%
Total			135.97		148.52	9.2%

3rd Quartile						
(N01)						
Daily Charge (c/day)	91	43.483	39.57	44.560	40.55	2.5%
First 500kWh per Quarter (c/kWh)	500	10.587	52.94	11.870	59.35	12.1%
Next 1,000kWh per Quarter (c/kWh)	884	9.528	84.23	10.980	97.06	15.2%
Remaining Consumption (c/kWh)	0	8.999		10.683		
(N06)						
Daily Charge (c/day)	91	14.845	13.51	15.313	13.94	3.2%
All Energy Charge (c/kWh)	1,675	0.837	14.02	0.990	16.59	18.3%
Total			204.26		227.49	11.4%

7.2.7. LV General Network – Business (N02) – this is equivalent to Aurora Retail tariff 22

Network Tariff N02		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
Daily Charge (c/day)	91	46.917	42.69	48.112	43.78	2.5%
First 500kWh per Quarter (c/kWh)	500	11.466	57.33	12.592	62.96	9.8%
Remaining Consumption (c/kWh)	472	8.999	42.48	10.683	50.43	18.7%
Total			142.50		157.17	10.3%
(1st Quartile)						
Daily Charge (c/day)	91	46.917	42.69	48.112	43.78	2.5%
First 500kWh per Quarter (c/kWh)	165	11.466	18.92	12.592	20.78	9.8%
Remaining Consumption (c/kWh)		8.999		10.683		
Total			61.61		64.56	4.8%
3rd Quartile						
Daily Charge (c/day)	91	46.917	42.69	48.112	43.78	2.5%
First 500kWh per Quarter (c/kWh)	500	11.466	57.33	12.592	62.96	9.8%
Remaining Consumption (c/kWh)	3,393	8.999	305.34	10.683	362.49	18.7%
Total			405.36		469.23	15.8%

7.2.8. *LV Nursing Homes (N02a) – this is equivalent to Aurora Retail tariff 34*

Network Tariff N02a		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
Daily Charge (c/day)	91	46.917	42.69	48.112	43.78	2.5%
First 500kWh per Quarter (c/kWh)	500	10.427	52.14	11.273	56.37	8.1%
Remaining Consumption (c/kWh)	167,000	5.501	9,186.67	5.947	9,932.19	8.1%
Total			9,281.50		10,032.33	8.1%
(1st Quartile)						
Daily Charge (c/day)	91	46.917	42.69	48.112	43.78	2.5%
First 500kWh per Quarter (c/kWh)	500	10.427	52.14	11.273	56.37	8.1%
Remaining Consumption (c/kWh)	5,817	5.501	319.99	5.947	345.96	8.1%
Total			414.82		446.11	7.5%
3rd Quartile						
Daily Charge (c/day)	91	46.917	42.69	48.112	43.78	2.5%
First 500kWh per Quarter (c/kWh)	500	10.427	52.14	11.273	56.37	8.1%
Remaining Consumption (c/kWh)	548,022	5.501	30,146.69	5.947	32,593.15	8.1%
Total			30,241.52		32,693.30	8.1%

7.2.9. *LV Metered Demand (kW) (N03) – this is equivalent to Aurora Retail tariff 83*

Network Tariff N03		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
Daily Charge (c/day)	91	202.940	184.68	210.987	192.00	4.0%
First 250kW Demand (c/kW/day)	52	48.921	2,314.94	57.272	2,710.11	17.1%
Additional Demand (c/kW/day)	0	44.093		51.622		
All Energy (c/kWh)	51,387	2.374	1,219.93	2.728	1,401.84	14.9%
Total			3,719.54		4,303.95	15.7%
(1st Quartile)						
Daily Charge (c/day)	91	202.940	184.68	210.987	192.00	4.0%
First 250kW Demand (c/kW/day)	25	48.921	1,112.95	57.272	1,302.94	17.1%
Additional Demand (c/kW/day)	0	44.093		51.622		
All Energy (c/kWh)	21,471	2.374	509.72	2.728	585.73	14.9%
Total			1,807.35		2,080.67	15.1%
3rd Quartile						
Daily Charge (c/day)	91	202.940	184.68	210.987	192.00	4.0%
First 250kW Demand (c/kW/day)	138	48.921	6,143.50	57.272	7,192.22	17.1%
Additional Demand (c/kW/day)	0	44.093		51.622		
All Energy (c/kWh)	125,325	2.374	2,975.22	2.728	3,418.87	14.9%
Total			9,303.39		10,803.08	16.1%

7.2.10. LV Metered Demand (kVA) (N09) – this is equivalent to Aurora Retail tariff 82

Network Tariff N09		Period 3 2009/10		P4 2010/11		
Median	Units	Network Price	$	Network Price	$	% Change
Daily Charge (c/day)	91	188.958	171.95	193.142	175.76	2.2%
First 250kVA Demand (c/kVA/day)	125	38.502	4,379.60	44.256	5,034.10	14.9%
Additional Demand (c/kVA/day)	0	34.703		39.890		
All Energy (c/kWh)	123,135	2.198	2,706.51	2.480	3,054.18	12.8%
Total			7,258.06		8,264.04	13.9%
(1st Quartile)						
Daily Charge (c/day)	91	188.958	171.95	193.142	175.76	2.2%
First 250kVA Demand (c/kVA/day)	61	38.502	2,137.25	44.256	2,456.64	14.9%
Additional Demand (c/kVA/day)	0	34.703		39.890		
All Energy (c/kWh)	48,595	2.198	1,068.12	2.480	1,205.33	12.8%
Total			3,377.32		3,837.73	13.6%
3rd Quartile						
Daily Charge (c/day)	91	188.958	171.95	193.142	175.76	2.2%
First 250kVA Demand (c/kVA/day)	250	38.502	8,759.21	44.256	10,068.20	14.9%
Additional Demand (c/kVA/day)	40	34.703	1,263.19	39.890	1,451.99	14.9%
All Energy (c/kWh)	278,150	2.198	6,113.74	2.480	6,899.10	12.8%
Total			16,308.08		18,595.05	14.0%

7.2.11. HV Metered Demand (kVA) (N10) – this is equivalent to Aurora Retail tariff 85

Network Tariff N10		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
Daily Charge (c/day)	91	181.114	164.81	186.044	169.30	2.7%
Demand Charge (c/kVA/day)	926	22.250	18,749.19	24.023	20,243.19	8.0%
All Energy (c/kWh)	901,858	1.150	10,371.36	1.439	12,974.26	25.1%
Total			29,285.36		33,386.74	14.0%
(1st Quartile)						
Daily Charge (c/day)	91	181.114	164.81	186.044	169.30	2.7%
Demand Charge (c/kVA/day)	498	22.250	10,083.26	24.023	10,886.73	8.0%
All Energy (c/kWh)	369,000	1.150	4,243.50	1.439	5,308.49	25.1%
Total			14,491.57		16,364.51	12.9%
3rd Quartile						
Daily Charge (c/day)	91	181.114	164.81	186.044	169.30	2.7%
Demand Charge (c/kVA/day)	1,904	22.250	38,551.24	24.023	41,623.14	8.0%
All Energy (c/kWh)	1,836,950	1.150	21,124.93	1.439	26,426.63	25.1%
Total			59,840.98		68,219.08	14.0%

7.2.12. HV Metered Demand (kW) (N11) – this is equivalent to Aurora Retail tariff 86

Network Tariff N11		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
Daily Charge (c/day)	91	190.692	173.53	198.268	180.42	4.0%
Demand Charge (c/kW/day)	515	28.270	13,248.74	31.089	14,569.64	10.0%
All Energy (c/kWh)	573,075	1.242	7,117.59	1.582	9,068.78	27.4%
Total			20,539.86		23,818.84	16.0%
(1st Quartile)						
Daily Charge (c/day)	91	190.692	173.53	198.268	180.42	4.0%
Demand Charge (c/kW/day)	227	28.270	5,839.73	31.089	6,421.96	10.0%
All Energy (c/kWh)	179,200	1.242	2,225.66	1.582	2,835.80	27.4%
Total			8,238.93		9,438.18	14.6%
3rd Quartile						
Daily Charge (c/day)	91	190.692	173.53	198.268	180.42	4.0%
Demand Charge (c/kW/day)	1,115	28.270	28,684.16	31.089	31,543.98	10.0%
All Energy (c/kWh)	1,044,000	1.242	12,966.48	1.582	16,521.05	27.4%
Total			41,824.17		48,245.46	15.4%

7.2.13. LV Day/Night Irrigation (N08) – this is equivalent to Aurora Retail tariff 73/74

Network Tariff N08		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
Daily Charge (c/day)	91	185.949	169.21	190.070	172.96	2.2%
Day Energy Charge (c/kWh)	2,882	11.466	330.48	12.592	362.94	9.8%
Night Energy Charge (c/kWh)	4,035	0.837	33.78	0.990	39.96	18.3%
Total			533.47		575.86	7.9%
(1st Quartile)						
Daily Charge (c/day)	91	185.949	169.21	190.070	172.96	2.2%
Day Energy Charge (c/kWh)	455	11.466	52.11	12.592	57.23	9.8%
Night Energy Charge (c/kWh)	508	0.837	4.25	0.990	5.03	18.3%
Total			225.58		235.23	4.3%
3rd Quartile						
Daily Charge (c/day)	91	185.949	169.21	190.070	172.96	2.2%
Day Energy Charge (c/kWh)	11,831	11.466	1,356.57	12.592	1,489.81	9.8%
Night Energy Charge (c/kWh)	15,809	0.837	132.32	0.990	156.55	18.3%
Total			1,658.10		1,819.33	9.7%

7.2.14. LV PAYG (N13) – this is equivalent to Aurora Retail PAYG tariff

Network Tariff N13		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
Daily Charge (c/day) All Energy)	91 2,818	35.812 7.368	32.59 207.61	36.567 6.760	33.28 190.47	2.1% -8.3%
Total			240.20	43.33	223.74	-6.9%
(1st Quartile)						
Daily Charge (c/day) All Energy)	91 2,096	35.812 7.368	32.59 154.41	36.567 6.760	33.28 141.66	2.1% -8.3%
Total			187.00		174.94	-6.5%
3rd Quartile						
Daily Charge (c/day) All Energy)	91 3,473	35.812 7.368	32.59 255.89	36.567 6.760	33.28 234.76	2.1% -8.3%
Total			288.48		268.04	-7.1%

7.2.15. LV ToU Residential – this is equivalent to Aurora Retail PAYG tariff

Network Tariff N13r		**Period 3 2009/10**		**P4 2010/11**		
Median	**Units**	**Network Price**	**$**	**Network Price**	**$**	**% Change**
Daily Charge (c/day)	91	45.368	41.28	46.383	42.21	2.2%
Peak Energy	1,066	9.528	101.55	11.286	120.28	18.4%
Shoulder Energy	855	6.051	51.76	7.167	61.31	18.5%
Off-Peak Energy	897	0.837	7.50	0.990	8.88	18.3%
Total			202.10		232.68	15.1%
(1st Quartile)						
Daily Charge	91	45.368	41.28	46.383	42.21	2.2%
Peak Energy	793	9.528	75.53	11.286	89.46	18.4%
Shoulder Energy	636	6.051	38.50	7.167	45.60	18.5%
Off-Peak Energy	667	0.837	5.58	0.990	6.60	18.3%
Total			160.89		183.87	14.3%
3rd Quartile						
Daily Charge	91	45.368	41.28	46.383	42.21	2.2%
Peak Energy	1,314	9.528	125.16	11.286	148.25	18.4%
Shoulder Energy	1,054	6.051	63.80	7.167	75.57	18.5%
Off-Peak Energy	1,105	0.837	9.25	0.990	10.94	18.3%
Total			239.49		276.97	15.6%

7.3. Comparison with Other Jurisdictions

The following graphs are presented to provide a comparison between the network charges levied by Aurora and those DNSPs in other Australian jurisdictions. The charges for the other DNSPs were estimated using the known load characteristics of Aurora network users and the published Network Tariffs of those DNSPs. For ease of comparison, Aurora's charges are taken to be 100%.

As a number of DNSPs have not released prices as yet, the comparison is against equivalent Period 3 tariffs in some cases.

Figure 1: Residential Tariff Comparison - Period 4

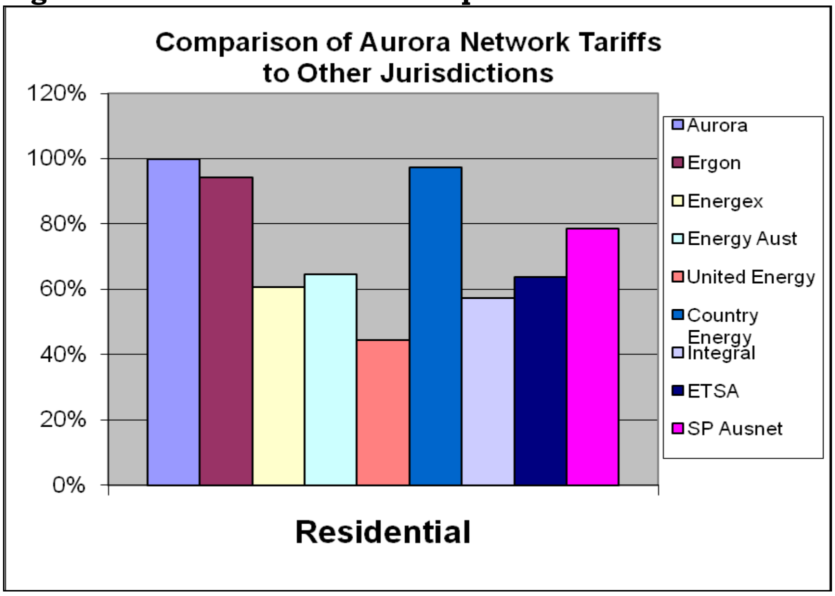


Figure 2: LV Business Tariff Comparison - Period 4

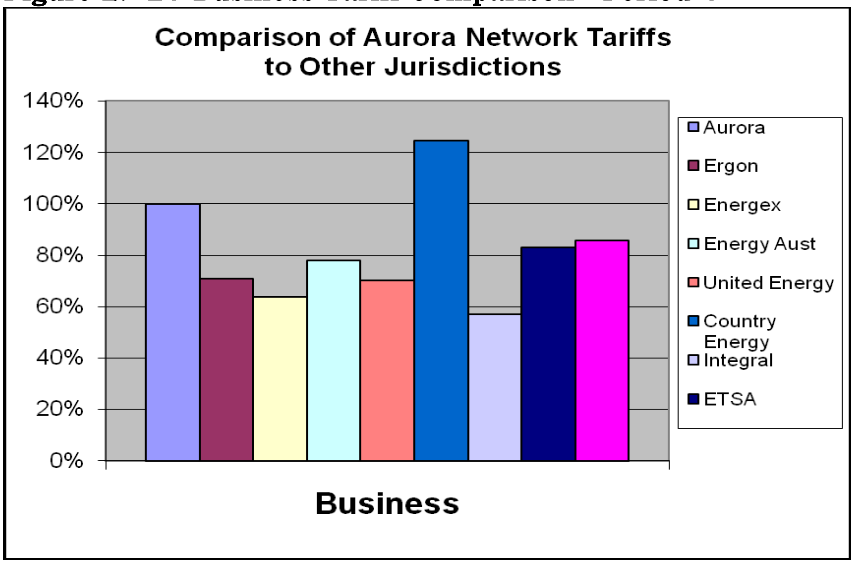


Figure 3: HV Demand (kVA) Tariff Comparison - Period 4

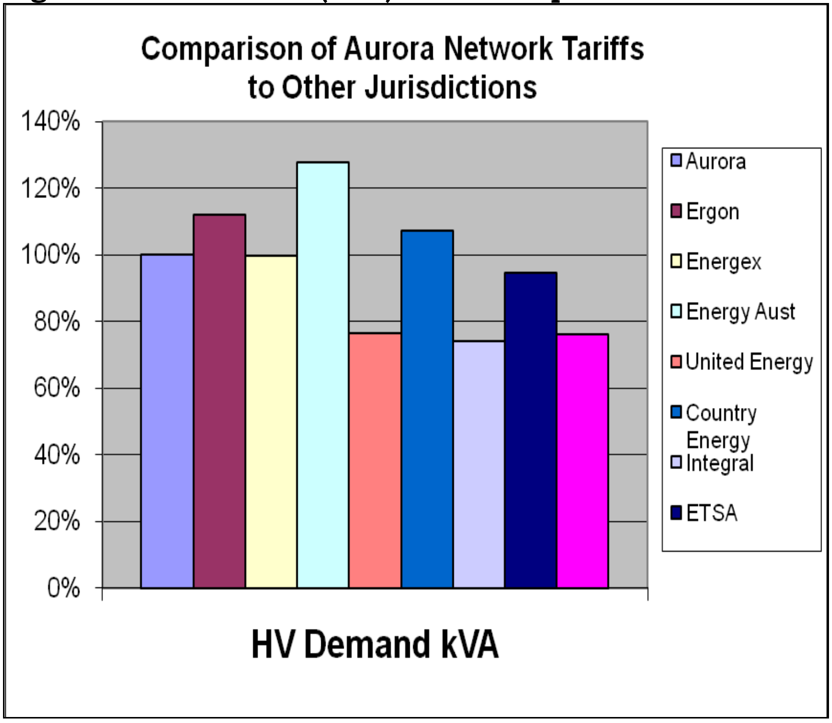
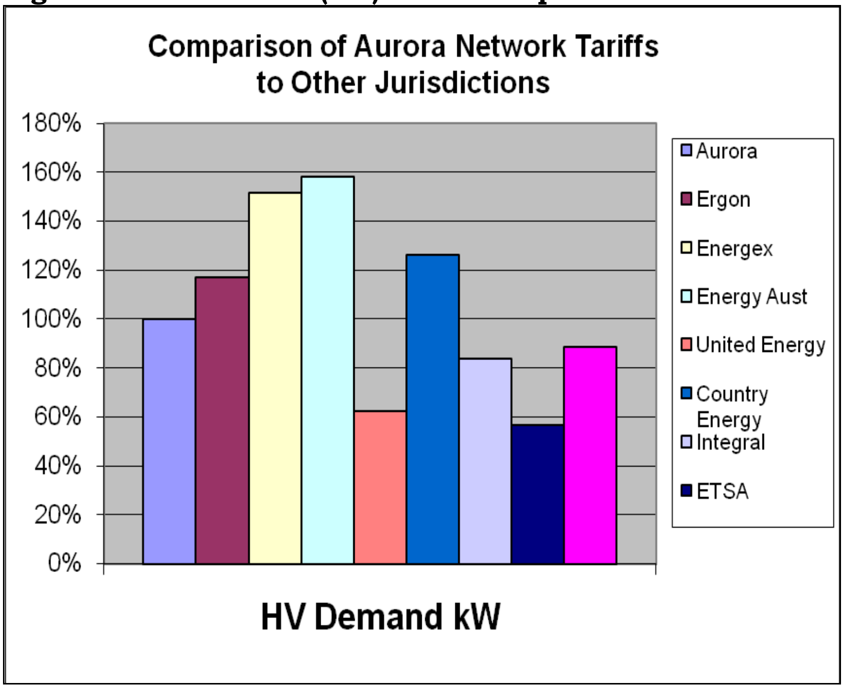


Figure 4: HV Demand (kW) Tariff Comparison - Period 4



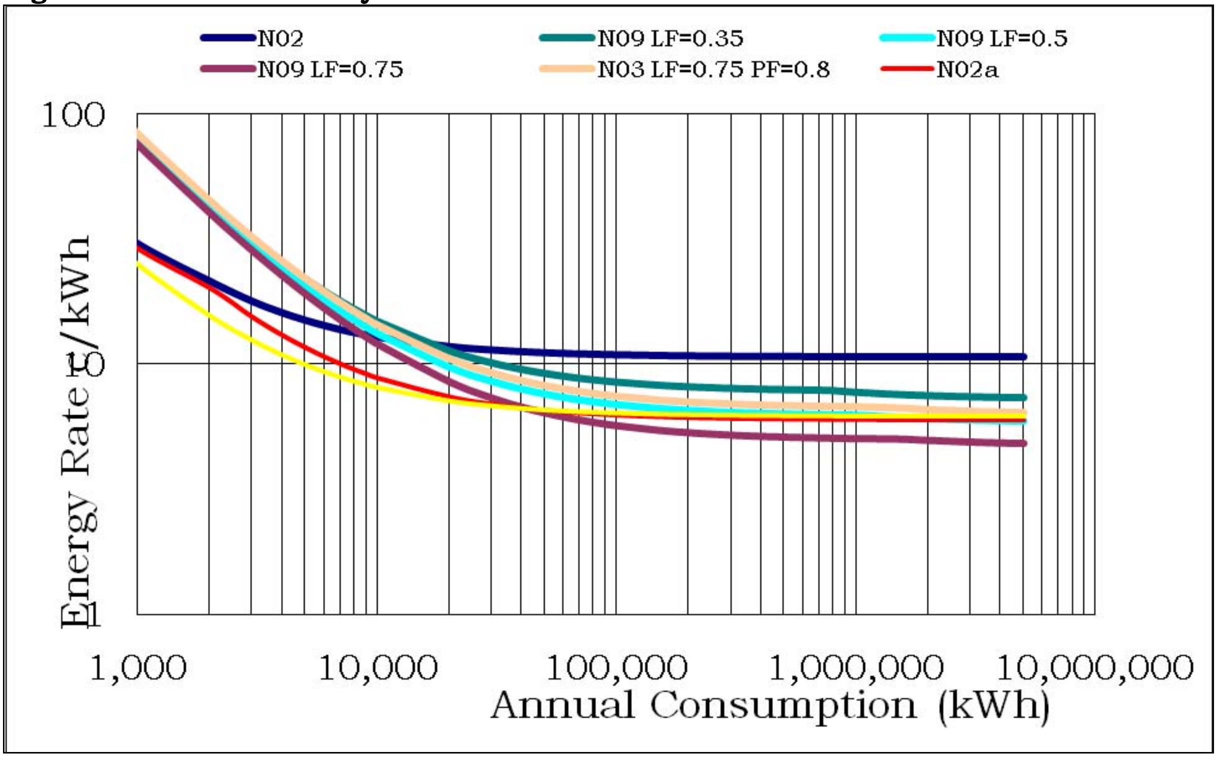
7.4. Cross-over Analysis

This section provides a series of cross-over analyses. These plots can be used to infer the annual consumptions at which any given Network Tariff becomes more efficient than another.

7.4.1. Small Customer Tariffs

Figure 5 provides comparisons between the General Network – Business N02 tariff and the two LV Metered Demand tariffs, N03 and N09 based upon the Proposed Period 4 Network tariffs.

Figure 5: Cross-over analysis for LV Business customers



8. Maximum Annual Revenue

The maximum annual revenue (AARR), which may be earned by Aurora for the provision of distribution services for each period as defined in the December 2007 Determination, is to be calculated on the following basis:

$$AARR_y = F_y \times PIF_y +$$
$$\left[\left(ESISC_y + NEMC_y + TMR_y + GSLse_y\right) \times {CPI_y}/{CPI_{y-1}} \times \left(1 + WACC\right)\right] +$$
$$K_{y-p} + NEM_y \times {CPI_y}/{CPI_{y-2}} + FRC_y + TAXA_y + L_y + CapCon_y +$$
$$GSLcap_y + CF_y + O_y$$

Throughout this document the CPI and WACC escalation factors are included in the calculation of the individual components, thus the formulae becomes:

$$AARR_y = F_y \times PIF_y + ESISC_y + NEMC_y + TMR_y + GSLse_y + K_{y-p} +$$
$$NEM_y + FRC_y + TAXA_y + L_y + CapCon_y + GSLcap_y + CF_y + O_y$$

$$AARR_4 = 209.697 \times \frac{169.5}{154.3} + 0.167 - 0.022 - 0.541 + 0.309 - 5.829 +$$
$$3.358 + 0 + 0 + 0 + 0 + 0 + 0 + 4.607$$

$$AARR_4 = 232.403\, m$$

The calculated aggregate annual revenue requirement for Period 4 (1 July 2010 to 30 June 2011) of the 2007 Pricing Determination is $232.403m.

Where,

y is the period as defined in the determination;

F_y is the forecast maximum AARR for each period defined in table 1 of the determination;

PIF_y is the prescribed inflationary factor for the relevant period as defined in the determination;

$ESISC_y$ is the difference between the actual electrical safety inspection service charge for period *y-1* and the relevant forecast for period *y-1* in table 2 of the determination;

$NEMC_y$ is the difference between the National Energy Market charge and that forecast in table 3 of the determination for the relevant period;

TMR_y is the PIF escalated difference between the actual charge for the State Government Trunk Mobile Radio network and that forecast in table 5 of the determination for periods 4 and 5.

$GSLse_y$ is the adjustment arising from the methodology set out in Schedule 1 of the determination for the GSL threshold;

CPI_y is the CPI for the quarter ending 6 months prior to the commencement of the relevant period, being 169.5;

CPI_0 is the Weighted Average of All Capital Cities CPI for the quarter ending 30 June 2006, being 154.3;

WACC is the Weighted Average Cost of Capital, being 6.64% for a full year;

$K_{y\text{-}p}$ is the adjustment for under or over recovery of allowable revenue in prior years due to variance in the customer base;

NEM_y is the PIF escalated difference between the actual allowance approved by the Regulator for period *y-2* and that forecast in table 4 of the determination for Aurora Distribution's participation in the NEM and retail contestability costs (excluding full retail contestability costs);

FRC_y is the allowance for the implementation of full retail contestability as approved by the Regulator;

$TAXA_y$ is the allowable tax event adjustment calculated in accordance with a methodology approved by the Regulator as consistent with Regulation 31(4) of the Price Control Regulations;

L_y is the allowable adjustment calculated in accordance with a methodology approved by the Regulator arising from changes in safety and/or environmental legislation;

$CapCon_y$ is the adjustment calculated in accordance with a methodology approved by the Regulator arising from a change to Aurora Distribution's capital contribution policies;

$GSLcap_y$ is the adjustment arising from the variance between actual payments to the PIF adjusted cumulative GSL threshold set out in table 6, calculated in accordance with the methodology set out in the determination;

CF_y is the adjustment arising from the administration of the 2003 Determination;

O_y is an adjustment approved by the Regulator to mitigate price fluctuations (no more than ±2% of F_y);

F_4, the forecast maximum AARR for Period 4, as defined in Table 1 of the 2007 Determination, is $209.697m;

PIF_4, the prescribed inflationary factor for Period 4 (CPI_y/CPI_0), is 169.5/154.3:

$ESISC_4$, the electrical safety inspection service charge difference, is \$0.167m;

$NEMC_4$, the National Energy Market charge difference, is -\$0.022m;

TMR_4, the PIF escalated State Government Trunk Mobile Radio network difference, is -\$0.541m;

$GSLse_4$, the adjustment arising from the methodology set out in Schedule 1 of the determination for the GSL threshold, is \$0.309m;

K_{4-p}, the adjustment for under or over recovery of allowable revenue in prior years due to variance in the customer base, is -\$5.829m;

NEM_4, the PIF escalated difference between the actual allowance approved by the Regulator for period *y-2* and that forecast in table 4 of the determination for Aurora Distribution's participation in the NEM and retail contestability costs (excluding full retail contestability costs), is \$3.358m;

FRC_4, the allowance for the implementation of full retail contestability as approved by the Regulator, is \$0;

$TAXA_4$, the allowable tax event adjustment calculated in accordance with a methodology approved by the Regulator as consistent with Regulation 31(4) of the Price Control Regulations, is \$0;

L_4, the allowable adjustment calculated in accordance with a methodology approved by the Regulator arising from changes in safety and/or environmental legislation, is \$0;

$CapCon_4$, the adjustment calculated in accordance with a methodology approved by the Regulator arising from a change to Aurora Distribution's capital contribution policies, is \$0;

$GSLcap_4$, the adjustment arising from the variance between actual payments to the PIF adjusted cumulative GSL threshold set out in table 6, calculated in accordance with the methodology set out in the determination, is \$0;

CF_4, the adjustment arising from the administration of the 2003 Determination, is \$0m; and

O_4, the adjustment approved by the Regulator to mitigate price fluctuations, is \$4.607m.

8.1. Weighted Average of All Capital Cities CPI, CPI_y

The weighted average of all capital cities CPI index number for the June and December quarter of each year will be that obtained from the Australian Bureau of Statistics web site, www.abs.gov.au or as amended from time to time.

The weighted average of all capital cities CPI index number for the December quarter of 2007 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 160.1.

The weighted average of all capital cities CPI index number for the December quarter of 2008 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 166.0.

The weighted average of all capital cities CPI index number for the December quarter of 2009 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 169.5.

8.2. Electrical Safety Inspection Service charge adjustment; $ESISC_y$

The adjustment for the difference between the actual electrical safety inspection service charge and the forecast charge for the previous period is to be calculated on the following basis:

$$ESISC_y = \left(ESISCa_{y-1} \times \frac{CPI_y}{CPI_{y-1}} - ESISCf_{y-1} \times \frac{CPI_y}{CPI_0} \right) \times (1 + WACC)$$

Where,

$ESISCa_{y-1}$ is the actual charge for the previous period, apportioned and CPI adjusted from the calendar year charge published in the Gazette[1];

$ESISCf_{y-1}$ is the forecast charge for the previous period, as detailed in Table 2 of the determination;

WACC is the Weighted Average Cost of Capital, being 6.64% for a full year;

CPI_0 is the Weighted Average of All Capital Cities CPI for the quarter ending 30 June 2006, being 154.3;

CPI_y is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the relevant period; and

CPI_{y-1} is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the period previous to the relevant period.

Forecast ESIS charge for Period 3, $ESISCf_{y-1}$

The forecast electrical safety inspection service charge for period 3, as shown in Table 2 of the determination, is $2.568m.

Actual ESIS charge for Period 3, $ESISCa_{y-1}$

The apportioned actual electrical safety inspection charge for period 3, as determined by the Minister and published in the Gazette, is $2.916m.

[1] The minister will determine the ESISC on a calendar year basis. Thus the actual ESISC for the period y-1 will be calculated assuming the calendar year costs are equally divided between each six month block and inflated by CPI as appropriate.

Weighted Average of All Capital Cities CPI, CPI_y

The weighted average of all capital cities CPI index number for the December quarter of 2009 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 169.5.

Weighted Average of All Capital Cities CPI, CPI_{y-1}

The weighted average of all capital cities CPI index number for the December quarter of 2008 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 166.0.

$$ESISC_4 = \left(2.916 \times \frac{169.5}{166.0} - 2.568 \times \frac{169.5}{154.3}\right) \times (1 + 0.0664)$$

$$ESISC_4 = 0.167m$$

For period 4, $ESISC_4$ = \$0.167m.

8.3. *Prior years under or over recovery of revenue adjustment; Ky-p*

The adjustment for under or over recovery of allowable revenue in prior years (K_{y-p}) for each period is to be calculated on the following basis:

$$K_{y-p} = \left(\sum_{y-2}^{CNa}\left[DNT_{y-2} \times CLe_{y-2}\right] - \sum_{y-2}^{CNe}\left[DNT_{y-2} - CLa_{y-2}\right]\right) \times \frac{CPI_y}{CPI_{y-2}} \times (1 + WACC_{y-2}) \times$$
$$(1 + WACC_{y-1}) + \left(\sum_{y-1}^{CNe}\left[DNT_{y-1} \times CLf_{y-1}\right] - \sum_{y-1}^{CNf}\left[DNT_{y-1} - CLe_{y-1}\right]\right) \times$$
$$\frac{CPI_y}{CPI_{y-1}} \times (1 + WACC_{y-1})$$

$$K_{y-p} = \left(DT\mathrm{Re}_{y-2} - DTRa_{y-2}\right) \times \frac{CPI_y}{CPI_{y-2}} \times (1 + WACC_{y-2}) \times$$
$$(1 + WACC_{y-1}) + \left(DTRf_{y-1} - DT\mathrm{Re}_{y-1}\right) \times \frac{CPI_y}{CPI_{y-1}} \times (1 + WACC_{y-1})$$

where,

$$DTRa_{y-2} = \left(\sum_{y-2}^{CNa}\left[DNT_{y-2} \times CLa_{y-2}\right]\right)$$

$$DT\mathrm{Re}_{y-2} = \left(\sum_{y-2}^{CNe}\left[DNT_{y-2} \times CLe_{y-2}\right]\right)$$

$$DTRf_{y-1} = \left(\sum_{y-1}^{CNf}\left[DNT_{y-1} \times CLf_{y-1}\right]\right)$$

$$DT\mathrm{Re}_{y-1} = \left(\sum_{y-1}^{CNe}\left[DNT_{y-1} \times CLe_{y-1}\right]\right)$$

Note: as the adjustment for the next period is calculated prior to the end of the current period, a forward estimate of the annual quantity is used and corrected in the subsequent period, also as per the definition of Distribution Network Tariff in the determination, excludes metering and transmission charge recovery.

Where,

CNf is the forecast number of customers at the start of the relevant period;

CLf is the forecast customer load for the relevant period;

CNe is the estimated number of customers at the start of the relevant period;

CLe is the estimated customer load for the relevant period;

CNa is the actual number of customers at the start of the relevant period;

DNT_{y-1} is the distribution network tariff for the period prior to the relevant period;

Cle_{y-1} is the estimated customer load for the period prior to the relevant period;

Clf_{y-1} is the forecast customer load for the period prior to the relevant period;

DNT_{y-2} is the distribution network tariff for the period before the previous period;

Cla_{y-2} is the actual customer load for the period before the previous period;

Cle_{y-2} is the estimated customer load for the period before the previous period;

$DTRa_{y-2}$ is the actual revenue from distribution network tariff for the period before the previous period;

$DTRe_{y-2}$ is the estimated revenue from distribution network tariff for the period before the previous period;

$DTRe_{y-1}$ is the estimated revenue from distribution network tariff for the period prior to the relevant period;

$DTRf_{y-1}$ is the forecast revenue from distribution network tariff for the period prior to the relevant period;

CPI_y is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the relevant period;

CPI_{y-1} is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the period previous to the relevant period;

CPI_{y-2} is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of two periods prior to the relevant period;

$WACC_{y-1}$ is the Weighted Average Cost of Capital in the previous period; and

$WACC_{y-2}$ is the Weighted Average Cost of Capital two periods previous.

Actual revenue from distribution tariff for Period 2, $DTRa_{y-2}$

The actual revenue from distribution tariffs for period 2 is $288.161m.

Estimated revenue from distribution tariff for Period 2, $DTRe_{y-2}$

The estimated revenue from distribution tariffs for period 2, as derived from the sum of the estimated number of customers, the estimated customer load and the distribution tariff for the period, is $280.047m.

Forecast revenue from distribution tariff for Period 3, $DTRf_{y-1}$

The forecast revenue from distribution tariffs for period 3, as derived Table 50 of the Period 3 Initial Network Tariff Pricing Proposal, is $318.037m. This figure is derived by taking the total revenue less metering revenue due to the price cap nature of the metering revenue stream.

Estimated revenue from distribution tariff for Period 3, $DTRe_{y-1}$

The estimated revenue from distribution tariffs for period 3, as derived from the sum of the estimated number of customers, the estimated customer load and the distribution tariff for the period, is $314.418m.

Weighted Average of All Capital Cities CPI, CPI_y

The weighted average of all capital cities CPI index number for the December quarter of 2009 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 169.5.

Weighted Average of All Capital Cities CPI, CPI_{y-1}

The weighted average of all capital cities CPI index number for the December quarter of 2008 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 166.00.

Weighted Average of All Capital Cities CPI, CPI_{y-2}

The weighted average of all capital cities CPI index number for the December quarter of 2007 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 160.1.

$$K_{4-p} = \left(DT\,\mathrm{Re}_{y-2} - DTRa_{y-2}\right) \times \frac{CPI_y}{CPI_{y-2}} \times \left(1 + WACC_{y-2}\right) \times \left(1 + WACC_{y-1}\right) + \left(DTRf_{y-1} - DT\,\mathrm{Re}_{y-1}\right) \times \frac{CPI_y}{CPI_{y-1}} \times \left(1 + WACC_{y-1}\right)$$

$$K_{4-p} = (280.047 - 288.161) \times \frac{169.5}{160.1} \times (1 + 0.0664) \times$$

$$(1 + 0.0664) + (318.037 - 314.418) \times \frac{169.5}{166.00} \times (1 + 0.0664)$$

$$K_{4-p} = -5.829\ m$$

For period 4, K_{4-p} = -\$5.829m

8.4. National Energy Market Charge Adjustment; $NEMC_y$

The adjustment for the difference between the actual National Energy Market charge and the forecast charge for the previous period is to be calculated on the following basis:

$$NEMC_y = \left(NEMCa_{y-1} \times \frac{CPI_y}{CPI_{y-1}} - NEMCf_{y-1} \times \frac{CPI_y}{CPI_0} \right) \times (1 + WACC)$$

Where,

$NEMCa_{y-1}$ is the actual charge for the previous period, apportioned and CPI adjusted from the annual charge published in the Gazette;

$NEMCf_{y-1}$ is the forecast charge for the previous period, as detailed in Table 3 of the determination;

WACC is the Weighted Average Cost of Capital, being 6.64% for a full year;

CPI_0 is the Weighted Average of All Capital Cities CPI for the quarter ending 30 June 2006, being 154.3; and

CPI_y is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the relevant period; and

CPI_{y-1} is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the period previous to the relevant period.

Forecast NEM charge for Period 3, $NEMCf_{y-1}$

The forecast NEM charge for period 3, as detailed in Table 3 of the determination, is \$0.365m.

Actual NEM charge for Period 3, $NEMCa_{y-1}$

The actual National Energy Market charge applicable to period 3, as determined by the Minister and published in the Gazette is \$0.372m.

Weighted Average of All Capital Cities CPI, CPI_y

The weighted average of all capital cities CPI index number for the December quarter of 2009 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 169.5.

Weighted Average of All Capital Cities CPI, CPI_{y-1}

The weighted average of all capital cities CPI index number for the December quarter of 2008 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 166.00.

$$NEMC_4 = \left(0.372 \times \frac{169.5}{166.0} - 0.365 \times \frac{169.5}{154.3}\right) \times (1 + 0.0664)$$

$$NEMC_4 = -0.022\ m$$

For period 4, $NEMC_4$ = - $0.022m

8.5. Trunk Mobile Radio Network Charge Adjustment; TMR_y

The adjustment for the difference between the actual trunk mobile network charge and the forecast charge for the previous period is to be calculated on the following basis:

TMR_1, TMR_2 and TMR_3 = 0

If contract is not renegotiated in period 3,

$$TMR_4 = -\$400{,}000 \times \frac{CPI_y}{CPI_0}$$

Otherwise,

$$TMR_y = \left(TMRa_{y-1} \times \frac{CPI_y}{CPI_{y-1}} - TMRf_{y-1} \times \frac{CPI_y}{CPI_0}\right) \times (1 + WACC)$$

Where,

$TMRa_{y-1}$ is the actual charge for the previous period;

$TMRf_{y-1}$ is the forecast charge for the previous period, as detailed in Table 5 of the determination;

WACC is the Weighted Average Cost of Capital, being 6.64% for a full year;

CPI_0 is the Weighted Average of All Capital Cities CPI for the quarter ending 30 June 2006, being 154.3;

CPI_y is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the relevant period, being 166.0; and

CPI_{y-1} is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the period previous to the relevant period, being 160.1;

Actual TMR charge for Period 3, $TMRa_{y-1}$

The actual TMR charge applicable to period 3 is $1.655m.

Forecast TMR charge for Period 3, $TMRf_{y-1}$

The forecast TMR charge for period 3, as detailed in Table 5 of the determination, is $2.00m.

Weighted Average of All Capital Cities CPI, CPI_y

The weighted average of all capital cities CPI index number for the December quarter of 2009 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 169.5.

Weighted Average of All Capital Cities CPI, CPI_{y-1}

The weighted average of all capital cities CPI index number for the December quarter of 2008 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 166.00

$$TMR_y = \left(TMRa_{y-1} \times \frac{CPI_y}{CPI_{y-1}} - TMRf_{y-1} \times \frac{CPI_y}{CPI_0} \right) \times (1 + WACC)$$

$$TMR_4 = \left(1.655 \times \frac{169.5}{166.0} - 2.00 \times \frac{169.5}{154.3} \right) \times (1 + 0.0664)$$

$$TMR_4 = -0.541\ m$$

For period 4, TMR_4 = -\$0.541m

8.6. GSL threshold Adjustment; $GSLse_y$

The adjustment for making single duration outage GSL payments to customers where the threshold for payments has been subsequently altered using the methodology described in Schedule 1 of the Determination and which has not previously been adjusted for is to be calculated on the following basis:

$$GSLse_y = \left(GSLse_{y-1} \times \frac{CPI_y}{CPI_{y-1}} \right) \times (1 + WACC)$$

Where,

$$GSLse_{y-1} = \sum_{events} \left(\frac{P}{2} \times 80 \right)$$

Where,

P is the number of payments made to customers who experienced an outage shorter than the adjusted threshold;

$GSLse_{y-1}$ is the sum of the payments made to customers who experienced an outage shorter than the adjusted threshold for the previous period;

WACC is the Weighted Average Cost of Capital, being 6.64% for a full year;

CPI_y is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the relevant period; and

CPI_{y-1} is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the period previous to the relevant period.

Actual GSLse charge for Period 2, $GSLse_{y-2}$

The actual GSLse charge applicable to period 2 is $0.256m.

Weighted Average of All Capital Cities CPI, CPI_y

The weighted average of all capital cities CPI index number for the December quarter of 2009 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 169.5.

Weighted Average of All Capital Cities CPI, CPI_{y-1}

The weighted average of all capital cities CPI index number for the December quarter of 2008 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 166.00

Weighted Average of All Capital Cities CPI, CPI_{y-2}

The weighted average of all capital cities CPI index number for the December quarter of 2007 as obtained from the Australian Bureau of Statistics web site, www.abs.gov.au, is 160.10

$$GSLse_y = \left(GSLse_{y-2} \times \frac{CPI_y}{CPI_{y-2}} \right) \times (1 + 0.0664) \times (1 + 0.0664)$$

$$GSLse_y = \left(0.256 \times \frac{169.5}{160.10} \right) \times (1 + 0.0664) \times (1 + 0.0664)$$

$$GSLse_4 = 0.309\ m$$

For period 4, $GSLe_4$ = $0.309

8.7. Participation in National Energy Market Adjustment; NEM_y

The adjustment for the difference between the actual allowance for period y-2 approved by the Regulator and the forecast allowance for period y-2 in relation to Aurora Distribution's participation in the NEM and retail contestability costs (but excluding full retail contestability costs) attributable to Aurora Distribution, as detailed in Table 4 of the Determination is to be calculated on the following basis:

$$NEM_y = \left(\left(NEMa_{y-2} - NEMf_{y-2} \times \frac{CPI_{y-2}}{CPI_0} \right) \times \frac{CPI_y}{CPI_{y-2}} \right) \times \left(1 + WACC_{y-2} \right) \times \left(1 + WACC_{y-1} \right)$$

Where,

$NEMf_{y-2}$ is the forecast revenue in relation to the preparation for and participation in the NEM for Aurora Distribution for period y-2 as detailed in Table 4 of the Determination;

$NEMa_{y-2}$ is the actual revenue in relation to the preparation for and participation in the NEM for Aurora Distribution for period y-2;

CPI_{y-2} is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of two periods prior to the relevant period;

CPI_y is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the relevant period;

CPI_0 is the Weighted Average of All Capital Cities CPI for the quarter ending 30 June 2006, being 154.3;

$WACC_{y-1}$ is the Weighted Average Cost of Capital in the previous period; and

$WACC_{y-2}$ is the Weighted Average Cost of Capital two periods previous.

$$NEM_4 = \left(\left(7.615 - 4.651 \times \frac{160.1}{154.3}\right) \times \frac{169.5}{160.1}\right) \times (1 + 0.0664) \times (1 + 0.0664)$$

For period 4, NEM_4 = \$3.358m

8.8. Allowance for implementation of Full Retail Contestability; FRC_y

There is no adjustment for implementation of Full Retail Contestability for Period 3.

For period 4, FRC_4 = \$0

8.9. Legislation change adjustment; L_y

There is no adjustment for legislative change for Period 3.

For period 4, L_4 = \$0

8.10. Capital Contribution policy adjustment; $CapCon_y$

There is no adjustment for variation to capital contribution policy for Period 4.

For period 4, $CapCon_4$ = \$0

8.11. SL payment adjustment; $GSLcap_y$

The adjustment for where total GSL payments to customers for period 1 to period y (inclusive) exceeds the cumulative threshold given in Table 6 of the Determination for is to be calculated on the following basis:

For Period 1:

$$GSLcap_y = \left(GSLa_{y-1} - GSLf_{y-1} \times \frac{CPI_y}{CPI_0}\right) \times (1 + WACC_{y-1})$$

For other periods:

$$GSLcap_y = \left(\sum_1^y GSLa_{\$2006} - GSLf_{y-1}\right) \times \frac{CPI_y}{CPI_0} \times (1 + WACC_{y-1})$$

Else, the adjustment for period 1 is zero and for all other periods the adjustment is zero less the sum of all adjustments made in periods 1 to y-1 (inclusive).

Where,

$GSLa_{y-1}$ is the actual GSL payments made in the previous period;

$GSLa_{\$2006}$ is the actual GSL payments made in the previous periods in \$2006;

$GSLf_{y-1}$ is the cumulative GSL threshold given in Table 6 of the Determination;

CPI_y is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the relevant period;

CPI_{y-1} is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of the period previous to the relevant period;

CPI_{y-2} is the Weighted Average of All Capital Cities CPI for the quarter ending six months prior to the start of two periods prior to the relevant period;

$WACC_{y-1}$ is the Weighted Average Cost of Capital in the previous period; and

$WACC_{y-2}$ is the Weighted Average Cost of Capital two periods previous.

There is no adjustment for GSL payments for Period 4.

For period 4, $GSLcap_4$ = \$0

8.12. Revenue banking adjustment; O_y

The maximum provision of Oy for revenue banking that can be utilised for any Period is equal to ± 2% of Fy.

The forecast Fy for Period 3, as derived from Table 1 of the determination, is \$209.697m.

For Period 4, the maximum value of O (Omax) is:

$$O_{max} = \pm 0.02 \times 209.697 \times \frac{169.5}{154.3}$$

$$O_{max} = \pm 4.607$$

For period 4, Aurora wishes to utilise a value of \$4.607 for O_4.

O_4 = \$4.607m

8.13. 8.12 Tax Event Adjustment; $TAXA_y$

There were no tax events in Period 3.

For period 4, $TAXA_4$ = \$0

8.14. 8.13 Adjustments arising from the administration of the 2003 Determination; CF_y

There is no adjustment arising from the administration of the 2003 Determination applicable for Period 4.

For period 4, CF_4 = \$0

9. Audit Certificate

This section is to address Guideline 2.3(d)(11): "A Network Tariff Pricing Proposal must…be accompanied by an internal audit certificate and certified as correct by the Chairman and one other Director of Aurora".

10. Definitions

"A" or ***"Amp"*** means ampere;

"AARR" means the aggregate annual revenue requirement determined in accordance with Clause 4 of the 2007 Determination;

"ABC" means aerial bundled cable;

"AER" means the Australian Energy Regulator;

"Aurora" means Aurora Energy Pty Ltd (ABN 85 082 464 622);

"charging parameters" of a Network Tariff means the constituent elements of the Network Tariff;

"Consumer Price Index" or ***"CPI"*** means the Consumer Price Index: Average All Capital Cities published by the Australian Statistician under the Census and Statistics Act 1905 of the Commonwealth;

"Contestable Customer Regulations" means the *Electricity Supply Industry (Contestable Customer) Regulations 2005*;

"customer" has the same meaning as in the TEC;

"distribution connected customer" means a distribution customer other than an electricity retailer, where distribution customer and electricity retailer have the same meaning as in the TEC;

"distribution Network Tariff" means the schedule of fees (including the rate or rates) Aurora uses to calculate the amount it charges customers, or a class of customers, to recover its AARR, as amended from time to time;

"DORC" means depreciated optimised replacement cost;

"DUoS" means Distribution Use of System;

"duration of the Determination" means the period from 1 January 2008 to 30 June 2012.

"ESI Act" means the *Electricity Supply Industry Act 1995*;

"Final Pricing Investigation Report" means the *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania, Final Report and Proposed Maximum Prices* issued in September 2007;

"FRC" means Full Retail Contestability;

"Guideline" means the *Approval of Network Tariffs in accordance with the 2007 Determination Guideline* issued by the Regulator in November 2007;

"HV" means high voltage;

"kVA" means kilovolt amp;

"kW" means kilowatt;

"kWh" means kilowatt hour;

"large customer" means a customer that is not a small customer;

"LV" means low voltage;

"National Electricity Law" or ***"NEL"*** has the same meaning as in the ESI Act;

"National Electricity Market" or ***"NEM"*** has the same meaning as in the ESI Act;

"National Electricity Rules" or ***"NER"*** has the same meaning as in the ESI Act;

"NEMMCO" has the same meaning as in the ESI Act;

"NEM related costs" means those costs incurred by Aurora in providing the declared services related to electricity market reform as approved by the Regulator under Clause 4 of the 2007 Determination;

"Network Tariff" means the schedule of fees (including the rate or rates) Aurora uses to calculate the amount it charges customers, or a class of customers, for network services, and for network services and metering services associated with a Type 5, 6 or 7 installation, as amended from time to time;

"NTS" means the Network Tariff Strategy;

"NUoS" means network use of system;

"ORC" means optimised replacement cost;

"Period 1" means the period commencing 1 January 2008 and ending on 30 June 2008;

"Period 2" means the period commencing 1 July 2008 and ending on 30 June 2009;

"Period 3" means the period commencing 1 July 2009 and ending on 30 June 2010;

"Period 4" means the period commencing 1 July 2010 and ending on 30 June 2011;

"Period 5" means the period commencing 1 July 2011 and ending on 30 June 2012;

"Price Control Regulations" mean the *Electricity Supply Industry (Price Control) Regulations 2003*;

"Regulator" has the same meaning as in the ESI Act;

"small customer" has the same meaning as in the 2007 Determination;

"TEC" means the Tasmanian Electricity Code (as amended from time to time), published by the Regulator under the ESI Act;

"ToU" means time of use;

"Transend" means Transend Networks Pty Ltd (ABN 57 082 586 892) or its successors;

"transmission charges" means those charges attributable to distribution connected customers imposed by Transend for the provision of transmission services in accordance with the NER;

"TUoS" means Transmission Use of System;

"typical customers" means a set of customers derived using the methodology described in the *Typical Electricity Customers Information Paper issued* by the Office of the Tasmanian Energy Regulator in March 2006;

"2007 Determination" means the *Electricity Supply Industry Pricing Policies Declared Electrical Services Pricing Determination* issued by the Regulator in accordance with the Price Control Regulations in October 2007.

11. Aurora 2010/11 Special Services Proposal

Aurora Energy - Distribution Special Services

Prices for the provision of Distribution Special Services for the period 1 July 2010 until 30 June 2011

Submission to the Energy Regulator

Version 1.0
May 2010

Special Services

In his Declared Electrical Services Pricing Determination[1] (Determination) the Regulator has prescribed a methodology for the calculation of Distribution Special Services charges for each period within the Regulatory Period (1 January 2008 – 30 June 2012).

The Determination states at clauses 4 and 5 of Division 2:

4. The charges imposed by Aurora Distribution for the provision of Special Services in periods 2 to 5 inclusive are to be determined in accordance with the principle that if each of those charges were to be applied to the relevant number of Distribution Special Services listed in Table 1 of Schedule 1, the sum of the result so obtained must not exceed the notional maximum revenue calculated in accordance with clause 5.

5. The notional maximum revenue which may be earned by Aurora Distribution for the relevant period for the provision of Distribution Special Services listed in Table 1 of Schedule 1, is to be calculated on the following basis:

    Notional Maximum Revenue in the relevant period is to be equal to $1 578 700 times the prescribed inflationary factor for the relevant period.

The Determination defines the *Wage Index* in section 2 as:

> **"Wage Index"** means the Labour Price Index Catalogue 6345.0, Table 11 "Wage Price Index: Ordinary Time Hourly Rates of Pay Excluding Bonuses. Sector by Industry - All Sectors, Electricity Gas, and Water Supply published by the Australian Statistician under the *Census and Statistics Act 1905* of the Commonwealth;

The Australian Statistician has renumbered the tables within Catalogue 6345.0 and Table 9 has now replaced Table 11 (Explanatory Notes – Appendix 3 Concordance of old to new tables). To remain consistent with the Determination, Aurora has therefore used Table 9 as the basis of its calculations.

Notional Maximum Revenue

The Notional Maximum Revenue (NMR) is calculated on the following basis:

$$NMR_y = 1{,}578{,}700 \times PIF_y$$

$$PIF_y = \frac{WPI_y}{WPI_0}$$

Where,

> WPI is the Labour Price Index, Catalogue 6345.0, Table 9b "Wage Price Index: Ordinary Time Hourly Rates of Pay Excluding Bonuses. Sector by Industry – All Sectors, Electricity, Gas and Water Supply published by the Australian Statistician under the *Census and Statistics Act 1905* of the Commonwealth.
>
> WPI_y is the Labour Price Index for the quarter ending 31 December 2009, being 103.6.
>
> WPI0 is the Labour Price Index for the quarter ending 30 June 2006, being 89.8.

[1] Investigation into Electricity Supply Industry Pricing Policies – Declared Electrical Special Services Pricing Determination; 1 July 2008

$$PIF_y = \frac{103.6}{89.8}$$

PIF_y = 1.154

NMR_y = 1,578,700 x 1.154

= 1,821,306

Proposed Prices for the Period 1 July 2010 to 30 June 2011

The charges that Aurora is proposing that the Regulator approve for the period 1 July 2010 to 30 June 2011, are detailed below and are categorised into the three Service Types of Energisation, De-energisation and Re-energisation; Meter Alteration; and Meter Test.

The agreement to deliver any services to the agreed guarantees stated within this document are made assuming that there is access to the metering and servicing assets, there are no safety issues associated with delivery of the service, the Electrical Contractor has performed work to agreed standards and the infrastructure is present to deliver the service.

Energisation, De-energisation and Re-energisation

Aurora proposes that six charges exist under this category:

- Connection site visit – no appointment $33.40

  Visit to a customer's premises during normal business hours where no appointment is required on the regular scheduled day for service delivery and the request is received from the retailer before 3:00pm the previous business day. The visit will be required to energise or de-energise an installation; energise or de-energise due to credit; or to perform special readings.

- Connection site visit – non-scheduled visit $117.80

  Visit to a customer's premises during normal business hours where the visit is required on the day of a customer's request and the request is received from the retailer before 11:00am on that day or on a day that is not a scheduled visit day and the request is received before 3:00pm the previous business day. The visit will be required to energise or de-energise an installation; energise or de-energise due to credit; or to perform special readings.

- Connection site visit – inspection required $132.10

  Visit to a customer's premises during normal business hours where an inspection is required prior to energisation.

- Connection site visit – same day premium service $222.90

  Visit to a customer's premises where the visit is to occur the same day but requested by the retailer after 11:00am on that day. The visit will be required to energise or an installation.

- Rectification of Illegal Connection $296.00

  Visit to a customer's premises during normal business hours to rectify an installation that has been illegally connected. Price does not include the cost to repair damaged equipment.

- Transfer of Retailer $0.00

  Transfer of a NMI to a new Retailer effective the same date of the scheduled meter reading where no site visit is required or communications are installed.

  If the requested work cannot be completed due to an issue at the customer's premises the full charge will apply.

Meter Alteration

Aurora proposes that seven charges exist under this category. All services to be delivered no later than 10 business days of receiving retailer service request, unless an alternate date for the service has been agreed. A retailer service request is to be received by 3:00pm on any business day, otherwise it will be deemed to have been received the next business day.

- Meter alteration – single phase $138.00

  Visit to a customer's premises during normal business hours to add or modify a single phase metering circuit.

- Meter alteration – three phase $160.00

  Visit to a customer's premises during normal business hours to add or modify a three phase metering circuit.

- Reconnect meter $88.40

  Visit to a customer's premises during normal business hours to reconnect a previously disconnected meter.

- Adjust time clock $90.10

  Visit to a customer's premises during normal business hours to adjust the time period of an existing time clock).

- Install/remove ERT metering $206.00
- Each additional meter - $180.00

  Visit to a customer's premises during normal business hours to install or remove an ERT meter.

- Meter Alterations – wasted visit $75.00

  Visit to a customer's premises during normal business hours to add or modify a metering circuit at the customer's request where the work could not be completed due to issues at the customer's premises.

- Meter Alterations – after hours (per hour) $147.50

  Visit to a customer's premises, at the request of the retailer, outside normal business hours to undertake the following services:

  - meter alteration;
  - reconnect meter;
  - adjust time clock; and
  - install/remove ERT metering.

  These services will be charged at a minimum rate of 2 hours plus an hourly rate for each additional hour or part thereof of onsite time.

  A minimum of a 2 hourly rate will also apply for a wasted visit where the service could not be completed due to issues at the customer's premises.

Meter Test

Aurora proposes that five charges exist under this category. All services to be delivered no later than 15 business days of receiving retailer service request, unless an alternate date for the service has been agreed. A retailer service request is to be received by 3:00pm on a business day, otherwise it will be deemed to have been received the next business day.

- Meter test – single phase $202.70

  Visit to a customer's premises during normal business hours to test a single phase meter at the customer's request. No fee will apply if the meter is found to be faulty.

- Meter test – multi phase $405.30

  Visit to a customer's premises during normal business hours to test a multi phase meter at the customer's request. No fee will apply if the meter is found to be faulty.

- Meter test – Current Transformer $326.55

  Visit to a customer's premises during normal business hours to test a Current Transformer meter at the customer's request. No fee will apply if the meter is found to be faulty.

- Meter test – wasted visit $75.00

  Visit to a customer's premises during normal business hours to test a meter at the customer's request where the test could not be completed due to issues at the customer's premises.

- Meter Test – after hours (per hour) $147.50

  Visit to a customer's premises, at the request of the retailer, outside normal business hours to undertake the following services:

  - meter test – single phase;
  - meter test – multi phase; and
  - meter test – current transformer.

  These services will be charged at a minimum rate of 2 hours plus an hourly rate for each additional hour or part thereof of onsite time.

  A minimum of a 2 hourly rate will also apply for a wasted visit where the service could not be completed due to issues at the customer's premises.

Compliance with Determination

The total charges that Aurora is proposing that the Regulator approve for the period 1 July 2010 to 30 June 2011 must be less than the NMR for the period ($1,821,306) and are detailed in the table below.

Table 1 – Service Types and Charges

Service Type	Number	Charge	Total
Disconnections	17,000	$33.40	$567,800
Transfer of supply	13,600	$33.40	$454,240
Reconnections	10,500	$33.40	$350,700
Same day reconnections[1]	800	$156.34	$125,071
Check Reads	1,200	$33.40	$40,080
Sub tenant read	200	$33.40	$6,680
Add circuit (meter) [2]	260	$140.95	$36,646
Alter circuit (meter) [2]	1,360	$140.95	$191,689
Test Single phase meter	90	$202.70	$18,243
Test Three phase meter	20	$405.30	$8,106
Test Current transformer meter	5	$326.55	$1,633
			$1,800,888

[1] This is a weighted average price for the provision of same day reconnections.

[2] This is a weighted average price for the provision of add circuit (meter) and alter circuit (meter) services.

Other Distribution Special Services

The charges that Aurora is proposing that the Regulator approve for the period 1 July 2010 to 30 June 2011 are detailed below.

The agreement to deliver any services to the agreed guarantees stated within this document are made assuming that there is access to the metering and servicing assets, there are no safety issues associated with delivery of the service, the Electrical Contractor has performed work to agreed standards and the infrastructure is present to deliver the service.

A retailer service request, for all services, is to be received by 3:00pm on any business day, otherwise it will be deemed to have been received the next business day.

<u>New Connection – Permanent Supply</u>

Service to be delivered no later than 10 business days of receiving retailer service request, unless an alternate date of installation has been agreed:

- Install meters & service $0.00

  Install permanent meters and service connection at customer's request during normal business hours.

- Install meters & service – wasted visit $127.00

  Visit to a customer's premises during normal business hours to establish supply at the retailer's request where the establishment could not be completed due to issues at the customer's premises.

- Install additional service span single phase $355.00
- Install additional service span multi Phase $505.00

  Install additional span of overhead service at customer's request during normal business hours.

- Supply Establishment – after hours (per hour) $75.00

  Visit to a customer's premises, at the request of the retailer, outside normal business hours to establish supply.

  These services will be charged at a minimum rate of 2 hours plus an hourly rate for each additional hour or part thereof of onsite time.

  A minimum of a 2 hourly rate will also apply for a wasted visit where the service could not be completed due to issues at the customer's premises.

Supply Abolishment - Removal of Meters and Service Connection

Service to be delivered no later than 5 business days of receiving retailer service request, unless an alternate date of removal has been agreed:

- Remove meters & service $234.50

  Remove meters and service connection or temporary supply at customer's request or building demolition during normal business hours.

- Remove meters & service – wasted visit $127.00

  Visit to a customer's premises during normal business hours to abolish supply or abolish temporary supply at the customer's request where the abolishment could not be completed due to issues at the customer's premises.

- Supply Abolishment – after hours (per hour) $147.50

  Visit to a customer's premises, at the request of the retailer, outside normal business hours to abolish supply.

  These services will be charged at a minimum rate of 2 hours plus an hourly rate for each additional hour or part thereof of onsite time.

  A minimum of a 2 hourly rate will also apply for a wasted visit where the service could not be completed due to issues at the customer's premises.

Renewable Energy Connection

Service to be delivered no later than 10 business days of receiving retailer service request unless an alternate date of installation has been agreed:

- Connection of renewable energy meter $138.00

  Supply and install single phase dual register basic import/export metering equipment at a customer premises during normal business hours.

- Connection of renewable energy meter – wasted visit $75.00

  Visit to a customer's premises during normal business hours to install renewable energy meter where the installation could not be completed due to issues at the customer's premises.

- Renewable Energy Connection – after hours (per hour) $147.50

  Visit to a customer's premises, at the request of the retailer, outside normal business hours to connect a renewable energy meter.

  These services will be charged at a minimum rate of 2 hours plus an hourly rate for each additional hour or part thereof of onsite time.

  A minimum of a 2 hourly rate will also apply for a wasted visit where the service could not be completed due to issues at the customer's premises.

New Connection - Temporary and Temporary in Perm

All services to be delivered no later than 10 business days of receiving retailer service request, unless an alternate date of installation has been agreed:

- Temporary single phase builders supply underground – temporary position $138.00

  Connection of a single phase underground builders supply in a temporary position to be removed when permanent supply connected. Does not include charge to remove temporary supply (refer Supply Abolishment).

- Temporary three phase builders supply underground – temporary position $160.00

  Connection of a three phase underground builders supply in a temporary position to be removed when permanent supply connected. Does not include charge to remove temporary supply (refer Supply Abolishment).

- Temporary single phase builders supply underground – permanent position $138.00

  Connection of a single phase underground builders supply in a permanent position. Does not include charge to transfer to permanent supply (refer Meter Alteration – single phase).

- Temporary three phase builders supply underground – permanent position $160.00

  Connection of a three phase underground builders supply in a permanent position. Does not include charge to transfer to permanent supply (refer Meter Alteration – three phase).

- Temporary single phase builders supply overhead – temporary position $473.85

  Connection of a single phase overhead builders supply in a temporary position to be removed when permanent supply connected. Does not include charge to remove temporary supply (refer Supply Abolishment).

- Temporary three phase builders supply overhead – temporary position $628.00

  Connection of a three phase overhead builders supply in a temporary position to be removed when permanent supply connected. Does not include charge to remove temporary supply (refer Supply Abolishment).

- Temporary single phase builders supply overhead – permanent position $335.85

  Connection of a single phase overhead builders supply in a permanent position. Does not include charge to transfer to permanent supply (refer Meter Alteration – single phase).

- Temporary three phase builders supply overhead – permanent position $468.00

  Connection of a three phase overhead builders supply in a permanent position. Does not include charge to transfer to permanent supply (refer Meter Alteration – three phase).

- Temporary builders supply – wasted visit $127.00

  Visit to a customer's premises during normal business hours to install a temporary builder's supply at the customer's request where the installation could not be completed due to issues at the customer's premises.

- Install additional service span single phase $355.00

  Install additional span of overhead service at customer's request during normal business hours.

- Install additional service span multi phase $505.00

  Install additional span of overhead service at customer's request during normal business hours.

- Supply Establishment – after hours (per hour) $147.50

  Visit to a customer's premises, at the request of the retailer, outside normal business hours to establish supply.

  These services will be charged at a minimum rate of 2 hours plus an hourly rate for each additional hour or part thereof of onsite time.

  A minimum of a 2 hourly rate will also apply for a wasted visit where the service could not be completed due to issues at the customer's premises.

New Connection – Temporary *Show & Carnival Connection*

All services to be delivered no later than 10 business days of receiving retailer service request, unless an alternate date of installation has been agreed:

- Temporary show supply – underground $138.00

  Connection of a temporary underground supply for a show or carnival. Does not include charge to remove temporary supply (refer Supply Abolishment).

- Temporary show supply – overhead mains $329.50

  Connection of a temporary overhead supply for a show or carnival where consumer's mains are to be attached to an existing Aurora pole. Does not include charge to remove temporary supply (refer Supply Abolishment).

- Temporary show supply – overhead service $473.85

  Connection of a temporary overhead supply for a show or carnival where an overhead service is required. Does not include charge to remove temporary supply (refer Supply Abolishment).

- Temporary show supply – wasted visit $127.00

  Visit to a customer's premises during normal business hours to install a temporary show supply at the customer's request where the installation could not be completed due to issues at the customer's premises.

Truck Tee-up

Tee-ups are to be requested on an Electrical Works Request (EWR). An attempt to contact the contractor will be made within 2 business days of receiving the EWR from the retailer. Once the tee-up date has been negotiated with the contractor, this date will be known as the "agreed date":

- Tee-up – normal hours $651.00

  Contractor requested tee-up with service connections crew whilst undertaking work at customer's installation during normal business hours.

- Tee-up – after hours $1,494.15

  Contractor requested tee-up with service connections crew whilst undertaking work at customer's installation after normal business hours.

- Tee-up – wasted visit – normal hours $127.00

  Contractor requested tee-up with service connections crew where service connections crew are not required once on site.

- Tee-up – wasted visit – after hours $539.20

  Contractor requested tee-up with service connections crew where service connections crew are not required once on site.

Miscellaneous Services

All services to be delivered no later than 10 business days of receiving service request, unless an alternate date for the service has been agreed:

- Open turret $104.25

  Open turret or cabinet for electrical contractor installing or altering customer's mains during normal business hours.

- Addition/Alteration to the connection point $252.55

  Disconnect and reconnect service connection for addition/alteration for the connection point.

- Miscellaneous service – wasted visit $75.00

  Contractor requested miscellaneous service with service connections crew where service connections crew are not required once on site.

12. Aurora 2010/11 Public Lighting Proposal

Aurora Energy - Street Lighting Services

Prices for the provision of
Street Lights
for the period
1 July 2010 until 30 June 2011

Version 1.0
May 2010

Document History

Date	Version	Comments
5 May 2010	1.0	Original

Background

Provision of Street Lighting is an 'excluded service' – unregulated and therefore excluded from the regulated maximum allowable revenue for the Distribution Business.

Aurora operates and maintains the street lighting system throughout Tasmania on behalf of councils and other Government road authorities. The objective of street lighting is to provide a lit environment conducive to the safe and comfortable movement of vehicular and pedestrian traffic during hours of darkness and the discouragement of illegal acts.

The public lighting provided for the community to illuminate outdoor public access areas after dark includes management of luminaire, fixtures, support brackets and control systems but excludes the support structures. Poles and lighting structures revenues are included in the calculation of maximum allowable revenue for distribution services.

Aurora's street lighting are classified by AS/NZS:1158 into the following categories:

- ***Category 'V'*** - generally referred to as major public street lighting, is applicable for roads that the visual requirements of motorists are dominant.
- ***Category 'P'*** - generally referred to as minor public lighting, is applicable for roads that the visual requirements of pedestrians are dominant. Also applicable to outdoor public areas, other than roads, where the visual requirements of pedestrians are dominant. eg outdoor shopping precincts.

Aurora has three additional categories of Lighting Services which fall under the street lighting umbrella and include, Surcharge Poles; NUoS charges for privately owned fittings, and Contract Lights. Lighting Service charges are based on an annual fee for charges relating to the use of Aurora owned assets and charges for usage of the network system.

Aurora owns the majority of the luminaires. Approximately 75 percent of street lighting is supported on distribution poles. The other 25 percent of street lighting is on dedicated poles and in most cases privately owned. There are 28 councils plus Department of Infrastructure, Energy & Resources (DIER), Marine Boards, Government Business Enterprises (GBE's), contract clients etc, who potentially have some ownership interest as well as being paying clients.

Proposed Prices for the Period 1 July 2010 to 30 June 2011

The charges that Aurora is proposing for the period 1 July 2010 to 30 June 2011, are detailed below and are categorised as Major and Minor fittings and Lighting Services.

Major Fittings

Major street lighting has historically been a combination of light sources including Mercury Vapour and Low and High Pressure Sodium Vapour. All new fittings installed for major street lighting are High Pressure Sodium Vapour with power factor correction installed. Major street lighting is designed and installed on major roads to a specified level as documented in Australian Standards AS/NZS: 1158 Series and AS/NZS: 3771 or as requested and agreed by the respective road authority.

The proposed charges for the period 1 July 2010 to 30 June 2011 are presented in Table 1.

Table 1 – Major Fittings

Major	Network Component	NUoS Component	Annual Charge
Current/New Fittings			
100W High Pressure Sodium Vapour	124.68	41.47	$ 166.15
150W High Pressure Sodium Vapour	129.27	62.20	$ 191.48
250W High Pressure Sodium Vapour	116.24	103.67	$ 219.92
400W High Pressure Sodium Vapour	34.70	165.88	$ 200.58
100W Metal Halide	137.41	41.47	$ 178.88
150W Metal Halide	140.06	62.20	$ 202.26
250W Metal Halide	140.90	103.67	$ 244.57
400W Metal Halide	146.34	165.88	$ 312.22
1x40W Fluorescent	58.35	16.59	$ 74.94
2x40W Fluorescent	58.35	33.18	$ 91.53
Obsolete Fittings			
125W Mercury Vapour	106.60	51.84	$ 158.43
250W Mercury Vapour	83.01	103.67	$ 186.69
400W Mercury Vapour	1.40	165.88	$ 167.28
50W Mercury Vapour	98.78	20.73	$ 119.52
600W High Pressure Sodium Vapour	1.40	248.82	$ 250.22
90W Low Pressure Sodium Vapour	150.22	37.32	$ 187.55

Minor Fittings

Minor street lighting is primarily Mercury Vapour. All new minor street lighting installations are 80 watt Mercury Vapour with power factor correction fitted. Minor public lighting is installed to a standard, however the spacing of luminaires is usually determined by what poles are available and to what costs the councils will accept. Street lighting in underground subdivisions is installed on dedicated columns that are spaced according to street light spacing specifications for the luminaires used at the time of installation.

The proposed charges for the period 1 July 2010 to 30 June 2011 are presented in Table 2.

Table 2 – Minor Fittings

Minor	Network Component	NUoS Component	Annual Charge
Current/New Fittings			
80W Mercury Vapour	101.58	33.18	$ 134.76
70W High Pressure Sodium Vapour	121.14	29.03	$ 150.17
70 watt Metal Halide	137.76	29.03	$ 166.79
2 x 24 watt 'T5' Fluorescent	137.33	19.91	$ 157.24
42 watt compact fluorescent Fluorescent	117.22	17.42	$ 134.64
80 watt Mercury vapour Decorative Range	194.97	33.18	$ 228.14
88 LED Light	139.48	38.57	$ 178.04
118 LED Lights	173.35	51.01	$ 224.36
Obsolete Fittings			
2 x 20W Fluorescent	120.17	16.59	$ 136.75
4 x 20W Fluorescent	186.79	33.18	$ 219.97
4 x 40W Fluorescent	185.67	66.35	$ 252.02
100W Incandescent	152.58	41.47	$ 194.05
60W Incandescent	162.66	24.88	$ 187.54
50W Mercury Vapour	98.78	20.73	$ 119.52
18W Low Pressure Sodium Vapour	144.84	7.46	$ 152.30

Lighting Services

Lighting services are the services Aurora offer that fall outside of the realm of Major and Minor Fittings, but fall under the umbrella of street lighting. Lighting services include Surcharge Poles, Network Use of System and Contract Lights. An annual charge is charged to customers for lighting services and the charges are set out in the tables below.

- Surcharge Poles

  Steel road lighting poles are principally owned by the authority who is the customer for that street light and as such, any maintenance and activity related to this pole is the responsibility of the customer.

  Historically, road lighting poles were installed at Aurora's cost and an annual surcharge was applied to the responsible authority to recover costs of the assets. This practice has now ceased with all poles now being owned by the authority for whom the street light is installed.

  The proposed charges for the period 1 July 2010 to 30 June 2011 are presented in Table 3.

Table 3 – Surcharge Poles

Surcharge Poles	Annual Charge
St Pole 6m	$ 64.48
St Pole 7.5-11m	$ 90.66
St Pole 12m	$ 142.88
St Pole 18.3m	$ 231.43
Wall Bracket	$ 31.36

- NUoS charges for Fittings

  NUoS charges for fittings are the network charges attributable to customers connected to the network, for the provision of services directly related to transmission and distribution use of system, for those fittings that are maintained by Aurora for and on behalf of a customer.

  The proposed charges for the period 1 July 2010 to 30 June 2011 are presented in Table 4.

Table 4 – NUoS Charges

NuOS Charges for Fittings that are not supplied by Aurora	Annual Charge
20W Fluorescent Telecom 24hr supply	$ 30.33
20W Fluorescent Telecom street light	$ 8.29
60W Incandescent Telecom street light	$ 24.88
40W Fluorescent Telecom 24hr supply	$ 58.24
1200W Incandescent Airway Hazard Beacon	$ 497.64
300W Tungsten Halogen	$ 124.41
1500W Quartz Halogen	$ 622.05

- Contract Lights

  Contract Lights are lights that provide a direct benefit to a customer. Contract lights may be on Aurora poles and connected to the street lighting street switch or on private poles and buildings, and all components of the installation including the light fitting and arm is maintained at the customers cost, except for replacement of the globe which is part of the contract lighting tariff.

  The proposed charges for the period 1 July 2010 to 30 June 2011 are presented in Table 5.

Table 5 – Contract Lights

Contract Lights	Annual Charge
60W Incandescent	$ 179.37
100W Incandescent	$ 243.09
200W Incandescent	$ 311.54
500W Incandescent	$ 566.09
20W Fluorescent	$ 68.00
2 x 20W Fluorescent	$ 98.87
3 x 20W Fluorescent	$ 123.46
4 x 20W Fluorescent	$ 154.84
40W Fluorescent	$ 84.53
2 x 40W Fluorescent	$ 132.24
3 x 40W Fluorescent	$ 174.09
4 x 40W Fluorescent	$ 216.10
50W Mercury Vapour	$ 111.05
80W Mercury Vapour	$ 126.19
125W Mercury Vapour	$ 193.65
250W Mercury Vapour	$ 330.94
400W Mercury Vapour	$ 507.79
70W High Pressure Sodium Vapour	$ 164.94
150W High Pressure Sodium Vapour	$ 227.58
250W High Pressure Sodium Vapour	$ 329.86
400W High Pressure Sodium Vapour	$ 512.54
150W Metal Halide	$ 268.49
250W Metal Halide	$ 358.31
400W Metal Halide	$ 484.47
1500W Quartz Halogen	$ 1,478.48

13. Schedule 8.1: Tasmanian Electricity Code

Schedules to Chapter 8

SCHEDULES TO CHAPTER 8

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SCHEDULE 8.1
METHOD OF CALCULATING SUPPLY RELIABILITY PERFORMANCE

(a) The method of calculating supply reliability performance is as follows:

Target	Column		Definition
Annual number of supply interruptions, on average, per supply reliability category	Column A	=	$\dfrac{\Sigma\,\Phi_{(j,C)}\,\Theta_j}{\Sigma\,\Theta_{(j,C)}}$
Annual number of supply interruptions, on average, per supply reliability area	Column B	=	$\dfrac{\Sigma\,\Phi_{(j,R)}\,\Theta_j}{\Sigma\,\Theta_{(j,R)}}$
Annual duration of supply interruptions, on average, per supply reliability category	Column C	=	$\dfrac{\Sigma\,\Delta_{(j,C)}\,\Theta_j}{\Sigma\,\Theta_{(j,C)}}$
Annual duration of supply interruptions, on average, per supply reliability area	Column D	=	$\dfrac{\Sigma\,\Delta_{(j,R)}\,\Theta_j}{\Sigma\,\Theta_{(j,R)}}$

Where:

$\Phi_{(j,C)}$ is the number of interruptions for transformer j in supply reliability category C in a year

$\Phi_{(j,R)}$ is the number of interruptions for transformer j in supply reliability area R in a year

$\Theta_{(j,C)}$ is the installed capacity of transformer j in supply reliability category C

$\Theta_{(j,R)}$ is the installed capacity of transformer j in supply reliability area R

Θ_j is the installed capacity of transformer j

$\Delta_{(j,C)}$ is the duration of outages for transformer j in supply reliability category C in a year

$\Delta_{(j,R)}$ is the duration of outages for transformer j in supply reliability area R in a year

Column refers to the relevant standard as outlined in Table 3 of Chapter 8.

Φ and *Δ* exclude:

- *outages* resulting from *generation*, *transmission* and third party causes;
- *outages* resulting from load shedding at Ministerial direction;
- momentary *outages* (ie *outages* of less than 1 minute);
- *outages* that are requested by the *customer*; and
- *outages* resulting from *disconnection* for non-payment.

Customers or causes damages to property or malfunction in electrical appliances, the *Distribution Network Service Provider* must notify the *Customer* that it must meet the above requirements and the *Customer* must comply with such a notice.

8.6.11 Interruptions to supply

(a) A *Distribution Network Service Provider* must use reasonable endeavours to ensure that the average number and duration of planned and unplanned interruptions per annum to the *supply* of electricity due to interruptions on the *distribution system*, calculated using the methodology outlined in Schedule 8.1, does not exceed the frequency and duration figures:

(1) of all *Customers* in all *supply reliability areas* within the relevant *supply reliability category* in column A and column C of Table 3; and

(2) of all *Customers* in each *supply reliability area* in the relevant *supply reliability category* in column B and column D of Table 3.

Table 3: Supply Reliability Standards

Supply reliability category	**Annual number of supply interruptions (on average)**		**Annual duration of supply interruptions (on average)**	
	Category A	**Area B**	**Category C**	**Area D**
Critical Infrastructure	0.2	0.2	30 mins	30 mins
High Density Commercial	1	2	60 mins	120 mins
Urban and Regional Centres	2	4	120 mins	240 mins
High Density Rural	4	6	480 mins	600 mins
Lower Density Rural	6	8	600 mins	720 mins

(b) On request, a *Distribution Network Service Provider* must make available to a *Customer* the applicable *supply reliability* standards relating to that *Customer's electrical installation* and the actual supply *reliability* performance of that *Customer's electrical installation*.

(c) Despite clause 8.6.11(a) and subject to Part 7 of the Electricity Supply Industry (Tariff Customers) Regulations 1998 and a requirement that the *Distribution Network Service Provider* must use its reasonable endeavours to act in accordance with the needs of *Customers* who have notified their *Electricity Retailer* that a person at their address is reliant upon life support equipment under Part 7 of the Electricity Supply Industry (Tariff Customers) Regulations 1998 and/or are classified as *sensitive loads*, the *Distribution Network Service Provider* may interrupt the *supply* of electricity to a *Customer's electrical installation* at any time for reasons including:

(1) planned maintenance or repair of the *Distribution Network Service Provider's distribution system*;

(2) unplanned maintenance or repair of the *Distribution Network Service Provider's distribution system* in circumstances where, in the opinion of the

14. Aurora Quarterly Performance Report

Aurora **ENERGY**

QUARTERLY ELECTRICITY NETWORK PERFORMANCE REPORT

1 January – 31 March 2010

April 2010

Network Division

Aurora ENERGY

APPENDICES

Declaration

I declare that the information provided in this Quarterly Performance Report for Aurora Energy Pty Ltd ABN 85 082 464 in its capacity as a distributor licensed under the Electricity Supply Industry Act 1995 is complete and accurate.

Andre Botha
General Manager
Network Division

1. SUMMARY

This is Aurora Energy's Network Performance Report for the third quarter of 2009/10, covering the period 1 January through to 31 March 2010.

The quarterly frequency values (SAIFI) for each of the five community categories were above their long term averages for the quarter with the exception of High Density Rural which was lower.

The quarterly duration (SAIDI) values were above the quarterly average for all community categories with the exception of Critical Infrastructure which was lower.

There were 45 communities identified as poor performing as defined by the Tasmanian Electricity Code (TEC) for the twelve-month period ending on 31 March 2010. This number has decreased since the previous reporting period.

The number of asset related interruptions for the quarter was greater than the long-term average for the quarter. However the contributions to both SAIFI and SAIDI from asset related interruptions were less than the long-term quarterly averages.

The number of vegetation related interruptions for the quarter was greater than the long-term average for the quarter. The contributions to both SAIFI and SAIDI from vegetation related interruptions were equal to the long-term quarterly averages.

2. DISTRIBUTION SERVICE PLAN

2.1. Overall Network Performance

Aurora calculates reliability indices using a connected capacity (kVA) basis for the system and a weighted connected kVA basis for communities as stipulated in the TEC.

2.1.1. Major Events

Major events are outages that have significant kVA-durations and proportionally significant impact on the performance of the network. The kVA-duration of an outage depends on the length of the outage and the connected kVA of installations affected.

Major events for the quarter include:

- 24 March 2010, Bridgewater Feeder 48185 tripped due to an asset connection failure. A maximum of 934 customers were affected during the 10 hour outage. The total kVA-duration for this outage was 51,584 kVA hours.
- 29 March 2010, Kingston Feeder 34261 tripped due to a swan hitting the high voltage line. A maximum of 1,433 customers were affected during the 5 hour outage. The total kVA-duration for this outage was 50,890 kVA hours.
- 28 March 2010, Trevallyn Feeder 61021 tripped due to a conductor failure. A maximum of 1,639 customers were affected during the 4 hour outage. The total kVA-duration for this outage was 42,873 kVA hours.
- 23 March 2010, Railton Feeder 85001 was affected by a branch falling onto the high voltage line. A maximum of 321 customers were affected during the 4 hour outage. The total kVA-duration for this outage was 38,029 kVA hours.

2.1.2. Major Event Days

There were no major event days this quarter.

2.1.3. Total Network Performance (including transmission and third party)

The number of interruptions (SAIFI) and total minutes off supply (SAIDI) experienced by installations are shown in Figures 1 and 2. These graphs include interruptions resulting from faults on the transmission network and faults due to third party interaction with Aurora's assets, such as vehicles colliding with poles or acts of vandalism.

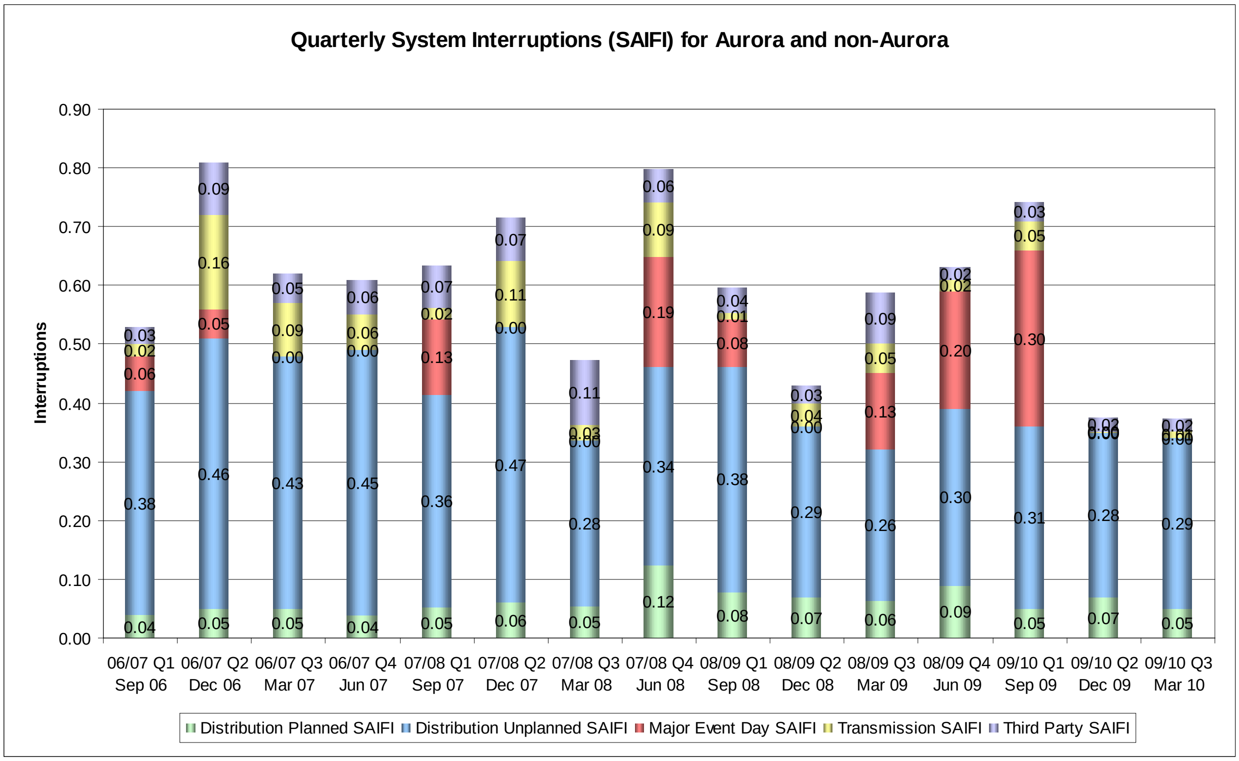

Figure 1: Quarterly System SAIFI (Aurora and Non-Aurora)

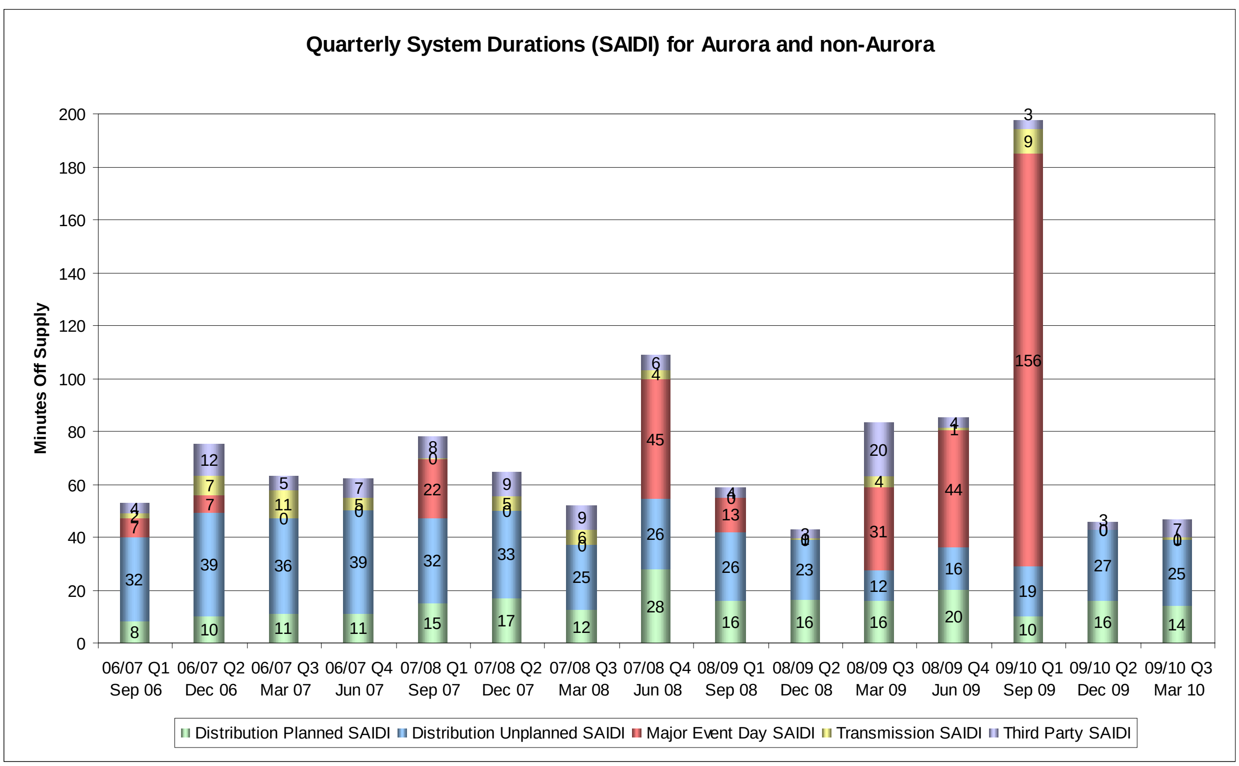

Figure 2: Quarterly System SAIDI (Aurora and Non-Aurora)

2.2. Distribution Network Performance

2.2.1. Performance Standards

The first, most general measure of network performance is concerned with the five community categories: Critical Infrastructure, High Density Commercial, Urban, High Density Rural and Low Density Rural. Each of these five categories has an associated frequency of outage standard and cumulative outage duration standard. Under the scheme, Aurora is required to use reasonable endeavours to ensure that:

- the frequency of outages for a category, averaged over all communities in that category, and
- the cumulative duration of outages for a category, averaged over all communities in that category

are less than the appropriate threshold set in the standards.

The second measure of network performance is related to individual communities. In this case, Aurora is required to use reasonable endeavours to ensure that:

- the frequency of outages for a community, averaged over all installations in that community, and
- the cumulative duration of outages for a community, averaged over all installations in that community,

are less than the appropriate threshold set in the standards.

The final measure of network performance is based around GSL payments, of which there are two varieties. The first kind occurs where an installation experiences a single outage of duration greater than a threshold determined by the Regulator. The second kind occurs where an installation experiences more than a certain number of outages in a twelve-month period. In both cases Aurora will issue a payment to the customer residing at the affected installation. If, however, an outage was caused by an event manifestly beyond the control of Aurora, Aurora may apply to the Regulator for the event to be treated as an exempt outage for the purposes of the GSL Scheme.

2.2.2. Community Performance

There were a total of 45 communities classified as poorly performing because they exceeded the TEC limits for frequency or duration over the 12-month period ending on 31 March 2010. These communities represent 37 per cent of the connected load of the distribution network.

Details of the performance of all communities can be found at Appendix A and further details of the performance of poor performing communities can be found at Appendix B.

The performance for each community and community category for the Quarter is presented in Tables 1, 2 and 3, with the Year-to-date (YTD) performance compared against the Annual YTD TEC standard for each category.

Community category	Frequency of Interruptions as at 31 March 2010							
	3rd Quarter 09/10		2009/10 Financial Year					
	Long Term Average	Actual	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Actual YTD	Annual Category Limit
Critical Infrastructure	0.09	0.12	0.01	0.04	0.12		0.17	0.20
High Density Commercial	0.12	0.30	0.06	0.15	0.30		0.51	1.00
Urban and Regional Centres	0.34	0.35	0.42	0.25	0.35		1.02	2.00
High Density Rural	0.77	0.71	1.55	0.54	0.71		2.8	4.00
Low Density Rural	0.82	0.83	1.62	0.98	0.83		3.43	6.00

Table 1: Category Performance by Frequency

Community category	Duration of Interruptions (minutes) as at 31 March 2010							
	3rd Quarter 09/10		2009/10 Financial Year					
	Long Term Average	Actual	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Actual YTD	Annual Category Limit
Critical Infrastructure	12	12	1	6	12		19	30
High Density Commercial	18	38	11	13	38		62	60
Urban and Regional Centres	34	41	94	35	41		170	120
High Density Rural	86	99	539	71	99		709	480
Low Density Rural	115	120	662	135	120		917	600

Table 2: Category Performance by Duration

Community category	TEC Community Performance for 12 months ending 31 March 2010					
	Frequency		Duration		Non-Compliant in Either	Non-Compliant in Both
	Individual Community Limit	Non-Compliant Communities	Individual Community Limit	Non-Complying Communities		
Critical Infrastructure	0.2	1/1	30	1/1	1/1	1/1
High Density Commercial	2	0/8	120	0/8	0/8	0/8
Urban and Regional Centres	4	2/32	240	16/32	16/32	2/32
High Density Rural	6	6/33	600	12/33	13/33	5/33
Low Density Rural	8	2/27	720	15/27	15/27	2/27
Totals		11/101		44/101	45/101	10/101

Table 3: Individual community performance against TEC Standards

The standard (Individual Community Limit) associated with the Urban and Regional Centres (Urban) category is recognised by Aurora and the Regulator as the most challenging of the standards to meet. This is due to the communities transferred to the category from the lower “Rural” classification of the previous regulatory period, where they had been subject to a lower reliability standard. As shown in Table 3 above, 16 of the 32 Urban communities are non-compliant (exceeding the set community performance limit).

The number of non-complying communities in the High and Low Density Rural categories (13 and 15 respectively) has stayed much the same since last quarter, these figures can be largely attributed to severe storms in the state in the 1st Quarter of 2009/10.

2.2.2.1. Community Performance by Frequency

The following figures show the overall frequency performance for each of the five categories for the last quarter compared to the long-term quarterly averages. The error bars for the long-term quarterly averages indicate plus/minus one standard deviation from the average; in a normally distributed data set, 66 per cent of values fall within one standard deviation of the average.

The overall frequency values for each of the five categories were above their long term averages for the quarter with the exception of High Density Rural which was lower. All categories, with the exception of High Density Commercial, were within one standard deviation of the average quarter performance observed over the previous five years. High Density Commercial was impacted by a switch gear failure in the Launceston CBD which tripped two feeders. This incident, occurring on the 6th February 2010, resulted in outages of up to 8 hours for some residents and businesses. Details of the incident were reported separately to the Regulator as a notifiable incident in a report dated 23rd March 2010.

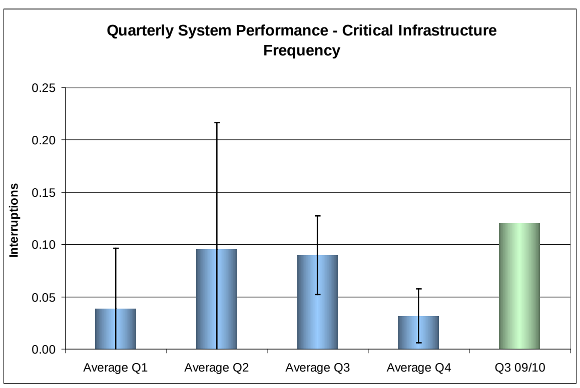

Figure 3: Critical Infrastructure

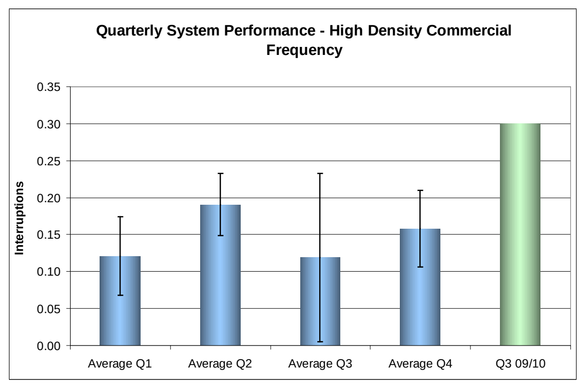

Figure 4: High Density Commercial

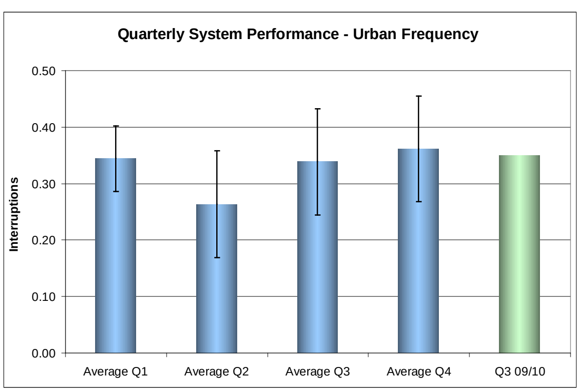

Figure 5: Urban

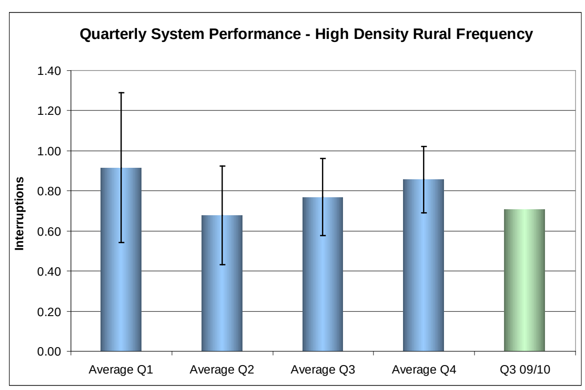

Figure 6: High Density Rural

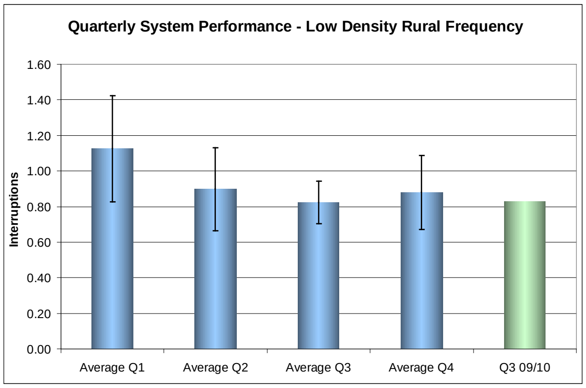

Figure 7: Low Density Rural

2.2.2.2. Community Performance by Duration

The following figures show the overall duration performance for each of the five categories for the last quarter compared to the long-term quarterly averages. The error bars for the long-term quarterly averages indicate plus/minus one standard deviation from the average; in a normally distributed data set, 66 per cent of values fall within one standard deviation of the average.

The quarterly duration value for Critical Infrastructure was below the long term average while the remaining categories were above. All five categories, with the exception of High Density Commercial, were within one standard deviation of the average quarter performance observed over the previous five years. High Density Commercial was impacted by a switch gear failure in Launceston CBD which tripped two feeders. This incident, occurring on the 6th February 2010, resulted in outages of up to 8 hours for some residents and businesses. Details of the incident were reported separately to the Regulator as a notifiable incident in a report dated 23rd March 2010.

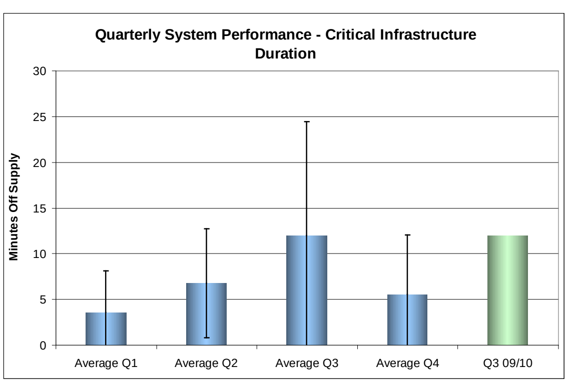

Figure 8: Critical Infrastructure

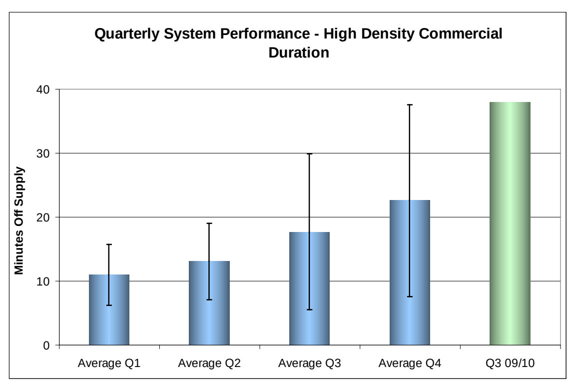

Figure 9: High Density Commercial

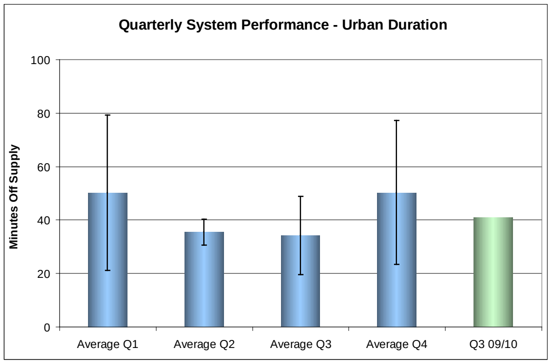

Figure 10: Urban

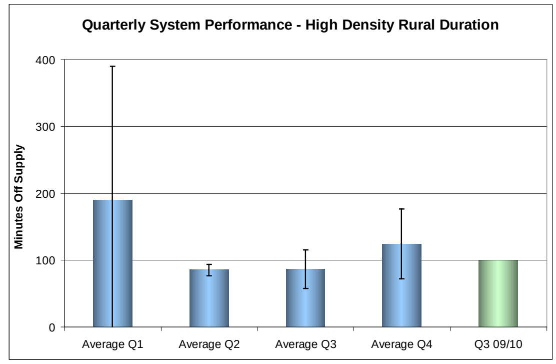

Figure 11: High Density Rural

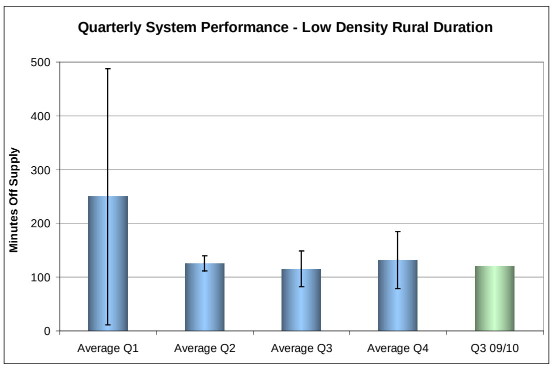

Figure 12: Low Density Rural

2.2.3. Guaranteed Service Levels

Timely restoration payments are made to customers residing at installations that experience a continuous outage greater than the outage duration standard for their community classification, as shown in Table 4.

Community Classification	Outage Duration (hours)	
Critical Infrastructure, High Density Commercial and Urban	> 8	> 16
High Density Rural	> 8	> 16
Low Density Rural	> 12	> 24
Timely Restoration Payment	$80	$160

Table 4: GSL conditions for timely restoration payments

Reliable supply payments are made to customers residing at installations that experience more outages than the outage count standard for their community classification in a rolling 12-month period, as shown in Table 5.

Community Classification	Outage Count
Critical Infrastructure, High Density Commercial and Urban	10
High Density Rural	13
Low Density Rural	16
Timely Restoration Payment	$80

Table 5: GSL conditions for reliable supply payments

The numbers of payments made to individual customers for the quarter are shown in Table 6. These figures relate to installations that became eligible for payment during the quarter and have been issued GSL payments accordingly.

	Qualifying Installations*	Payments made	$ paid
Timely Restoration > 8 or 12 hours	112	14,676	1,174,080
Timely Restoration > 16 or 24 hours	7	10,754	1,720,640
Sub Total Timely Restoration	119	25,430	2,894,720
Reliable Supply payments > 10 count (Critical Infrastructure, HD Commercial & Urban)	2	91	7,280
Reliable Supply payments > 13 count (HD Rural)	40	180	14,400
Reliable Supply payments > 16 count (LD Rural)	54	131	10,480
Sub Total Reliable Supply	96	402	32,160
Total GSL	**215**	**25,832**	**2,926,880**

Table 6: GSL Payments

* These installations qualified for GSL payments during the reporting period, however whether they were paid or not in that timeframe is dependent on how close the outage was to the end of the quarter, the degree of data validation required to confirm the outage, and if payments were on hold because they pertained to outages occurring on a day for which Aurora has sought to have the outage treated as an exempt outage for the purpose of the GSL Scheme.

2.3. Causes of Supply Interruptions

Causes of interruptions to supply are, in most cases, identified based on information provided by field crews who have located the fault and restored supply.

Analysing causes of faults can assist Aurora in understanding how the distribution network performs under different influences. Whilst Aurora has no control over when or where gale force winds blow or lightning strikes, it can strive to improve how the network operates under these conditions.

The breakdown and associated impact on supply reliability of the various causes is shown figures 13, 14 and 15.

Asset related outages also include service fuses that have high volumes but low impacts on the overall performance of the distribution network. There were 886 asset related events for the quarter (including 366 service fuse failures), which gives an exclusive count of 520. This is an increase on the previous quarter's count of asset related events, which was 464 excluding service fuse failures.

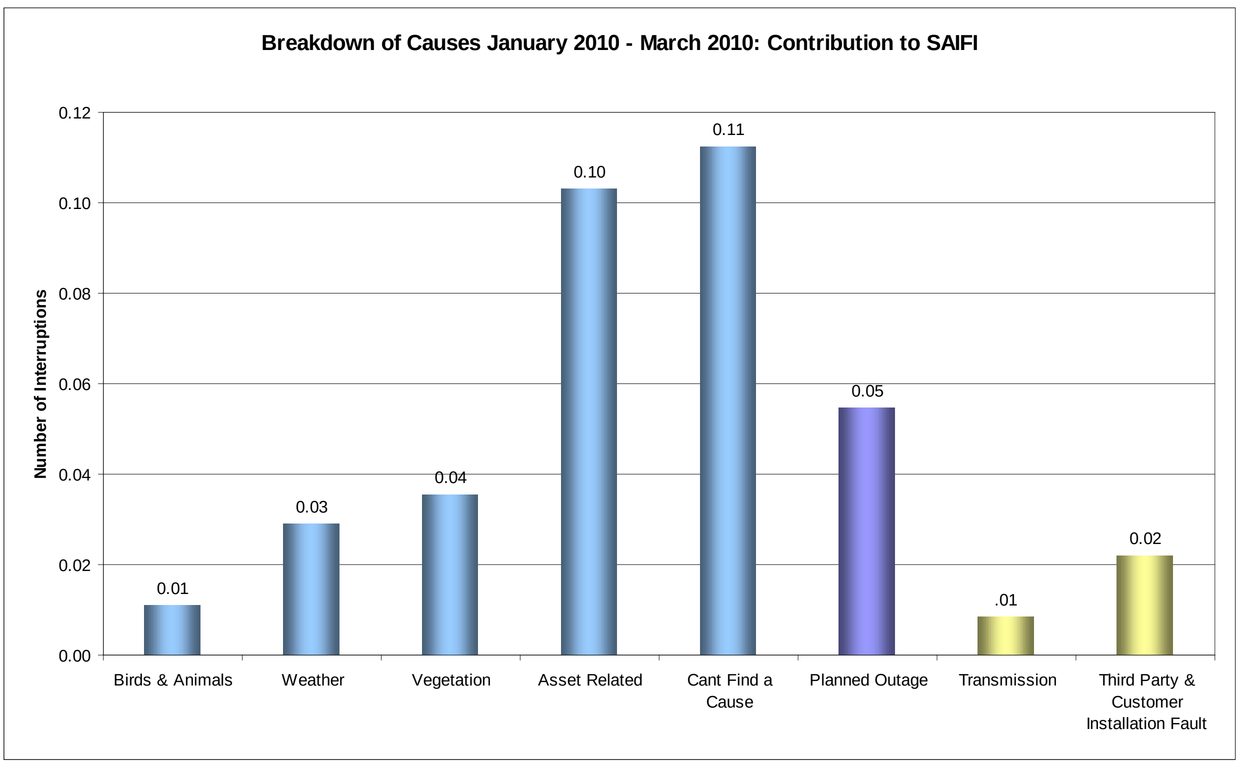

Figure 13: Contributions to SAIFI 1 January 2010 to 31 March 2010

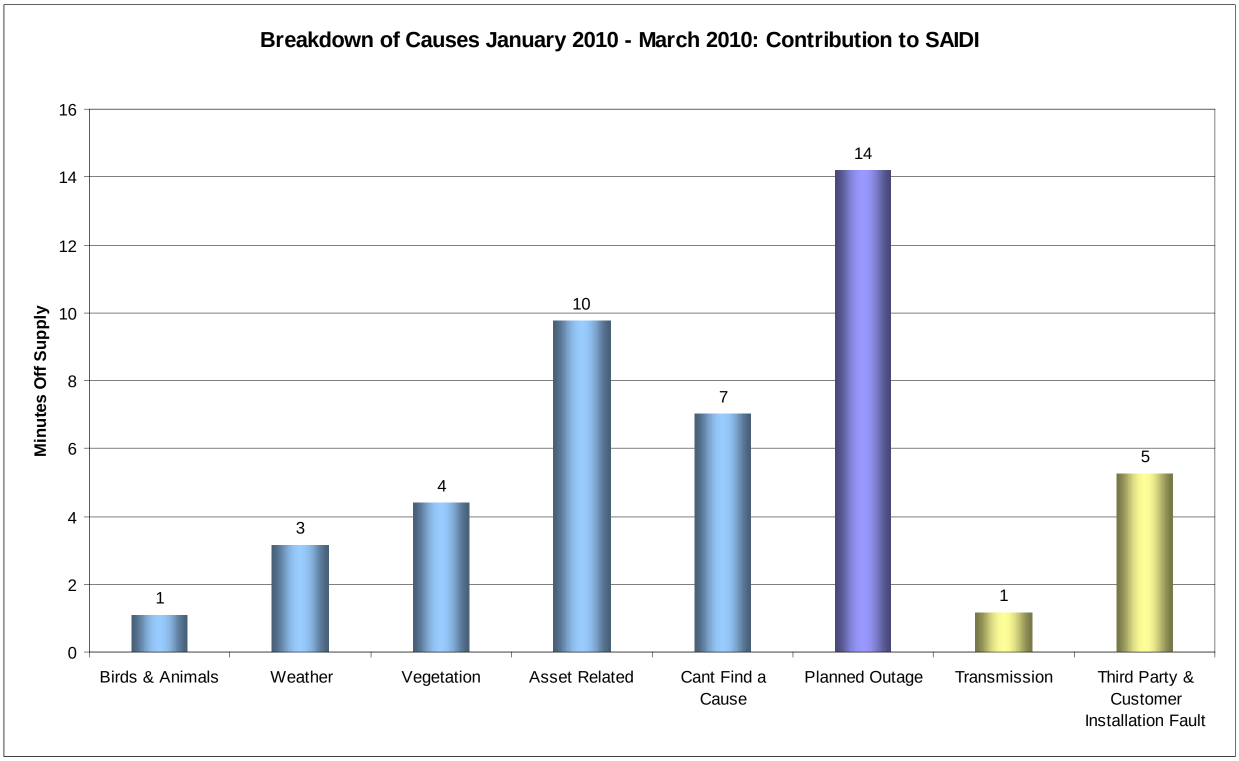

Figure 14: Contribution to SAIDI 1 January 2010 to 31 March 2010

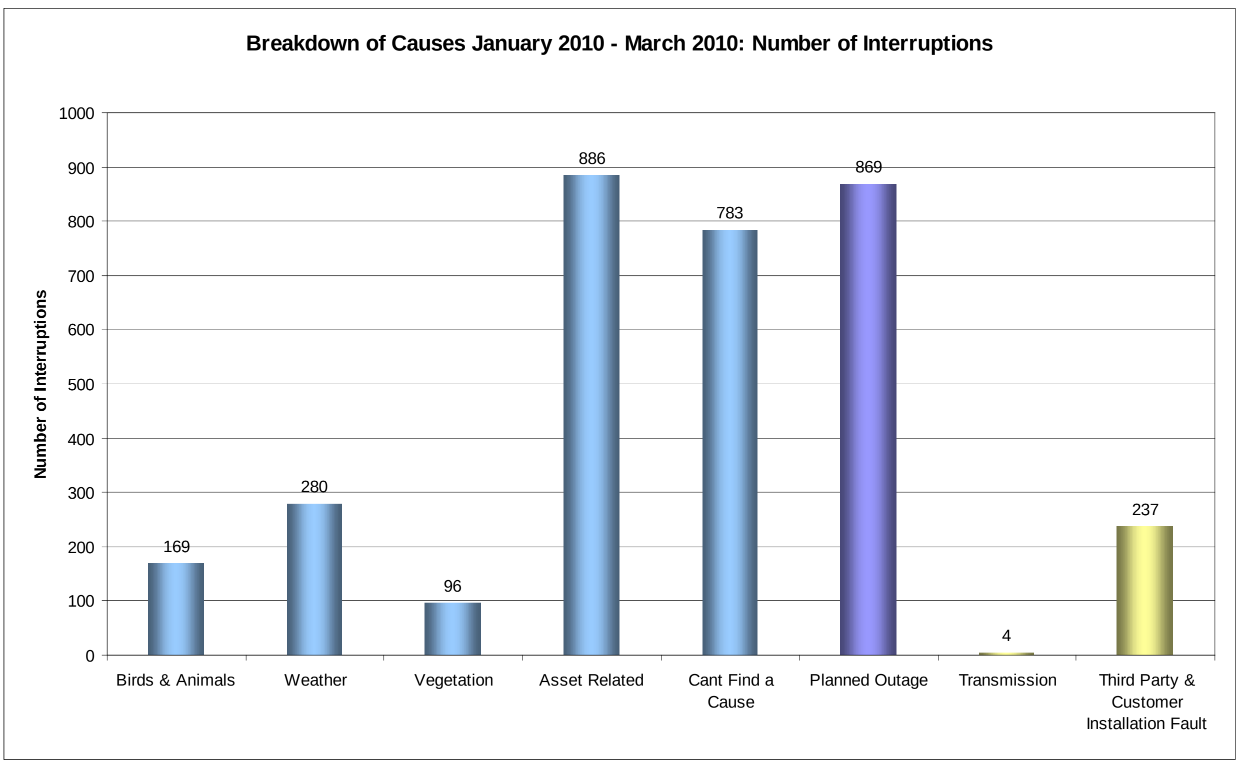

Figure 15: Number of Interruptions 1 January 2010 to 31 March 2010

2.3.1. Asset Related Interruptions

Figures 16, 17 and 18 show the impact of asset related interruptions on the performance of the distribution network for the quarter compared to the long-term quarterly averages. The error bars for the long-term quarterly averages indicate plus/minus one standard deviation from the average; in a normally distributed data set, 66 per cent of values fall within one standard deviation of the average.

There were a total of 886 asset related interruptions for the quarter. This value is greater than the long term average of 658 interruptions for the quarter but is within one standard deviation of the observed long-term average (± 245 events).

The contribution to SAIFI of 0.10 interruptions from asset related interruptions is less than the long-term average value of 0.14 interruptions for the quarter and is within one standard deviation of the observed long-term average (± 0.05 interruptions).

The contribution to SAIDI of 10 minutes from asset related interruptions is less than the long-term average value (13 minutes) for the quarter but is within one standard deviation of the observed long-term average (± 4 minutes).

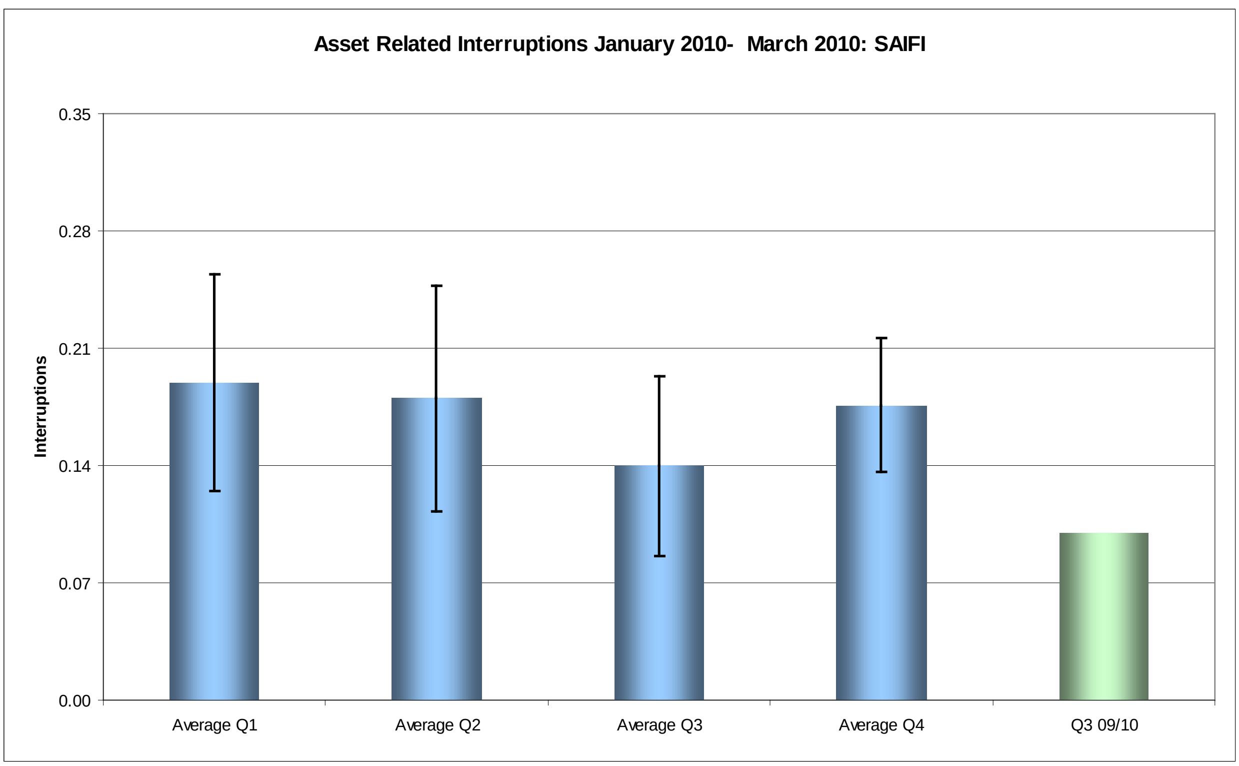

Figure 16: Contribution to SAIFI 1 January 2010 to 31 March 2010

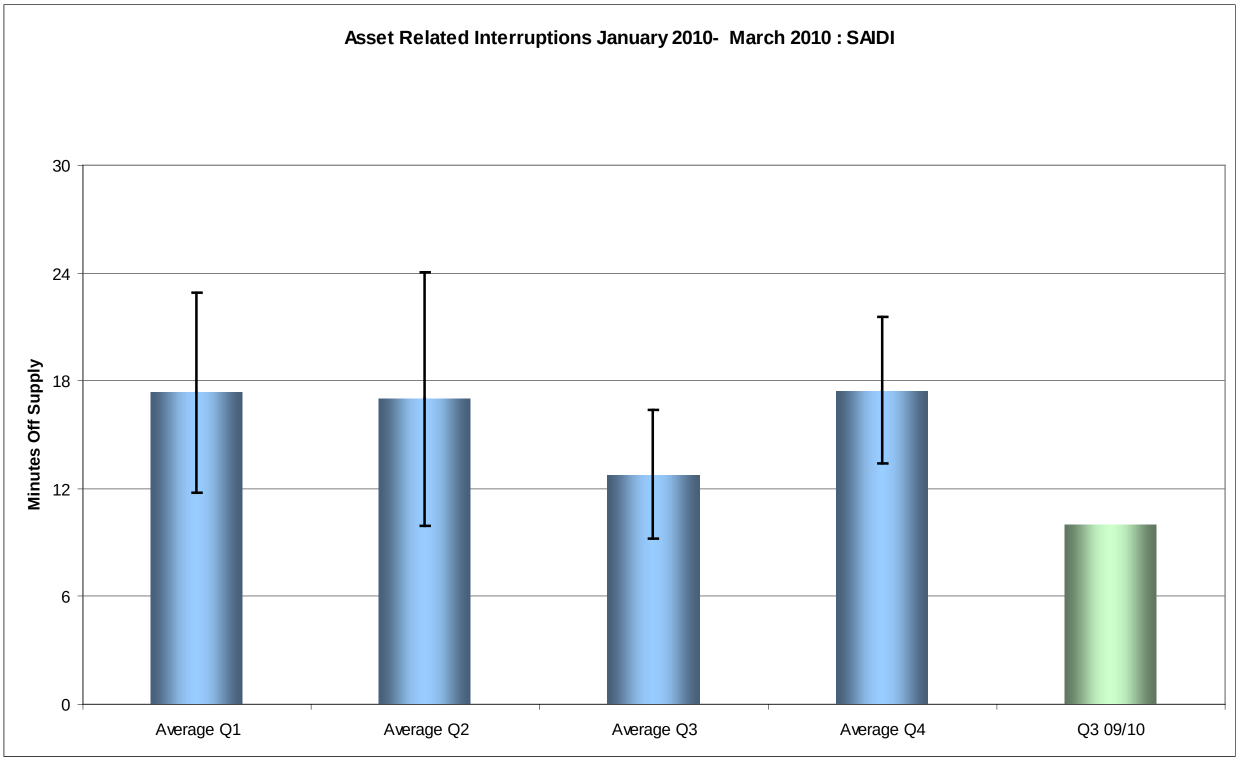

Figure 17: Contribution to SAIDI 1 January 2010 to 31 March 2010

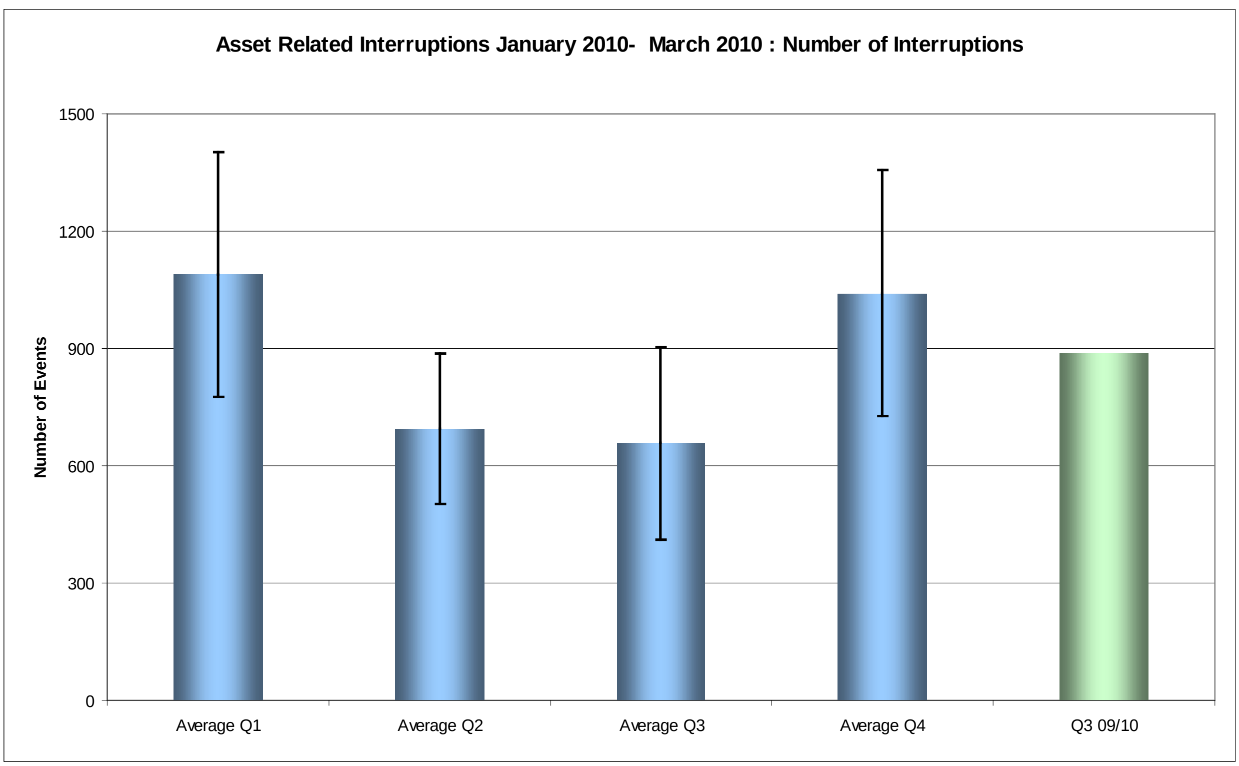

Figure 18: Number of Interruptions 1 January 2010 to 31 March 2010

2.3.2. Vegetation Related Interruptions

Figures 19, 20 and 21 show the impact of vegetation related interruptions on the performance of the distribution network for the quarter compared to the long-term quarterly averages. The error bars for the long-term quarterly averages indicate plus/minus one standard deviation from the average; in a normally distributed data set, 66 per cent of values fall within one standard deviation of the average.

There were 96 vegetation related interruptions during the quarter. This value is greater than the long-term average for the quarter (92) but within one standard deviation (± 24 events) of the long-term average. Of the 96 interruptions, 65 were caused by vegetation from outside the clearance zone and, therefore, beyond the control of Aurora's normal vegetation management practices.

The contribution to SAIFI of 0.04 interruptions from vegetation related interruptions is equal to the long-term average of 0.04 interruptions for the quarter.

The contribution to SAIDI of 4 minutes from vegetation related interruptions is equal to the long-term average of 4 minutes for the quarter.

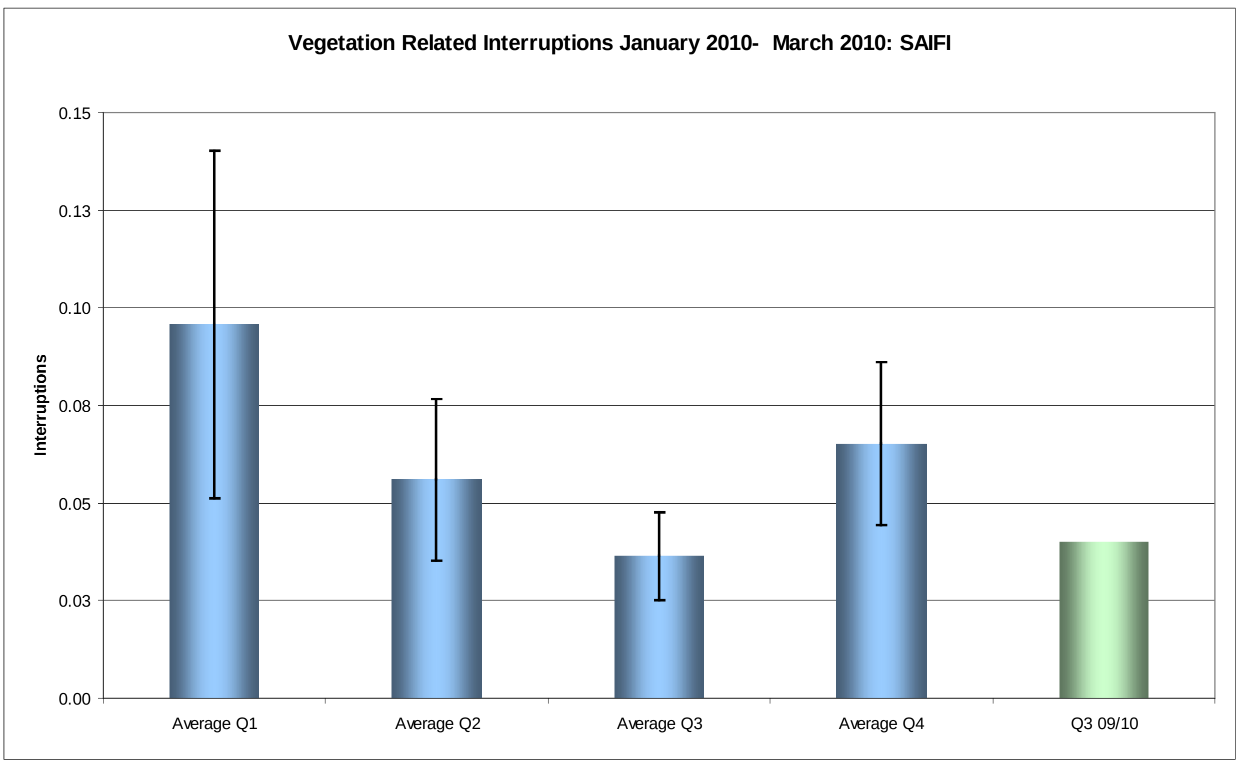

Figure 19: Contribution to SAIFI 1 January 2010 to 31 March 2010

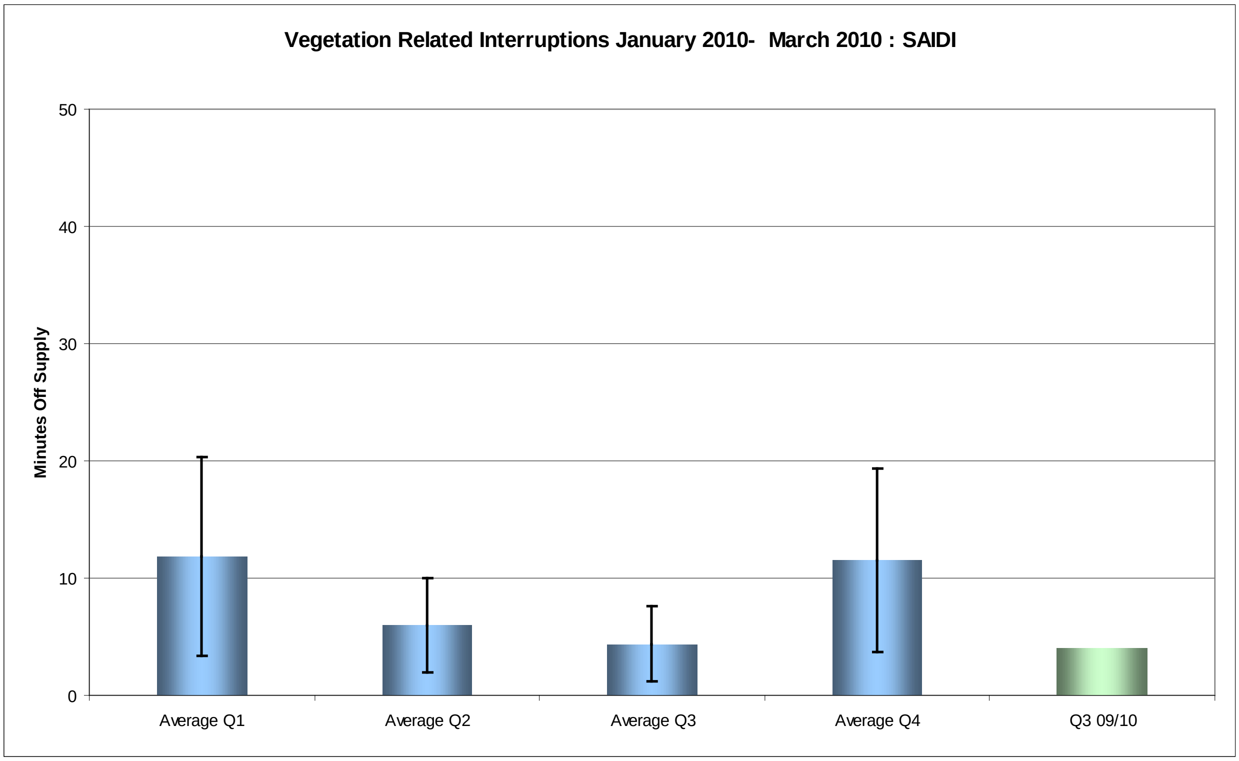

Figure 20: Contribution to SAIDI 1 January 2010 to 31 March 2010

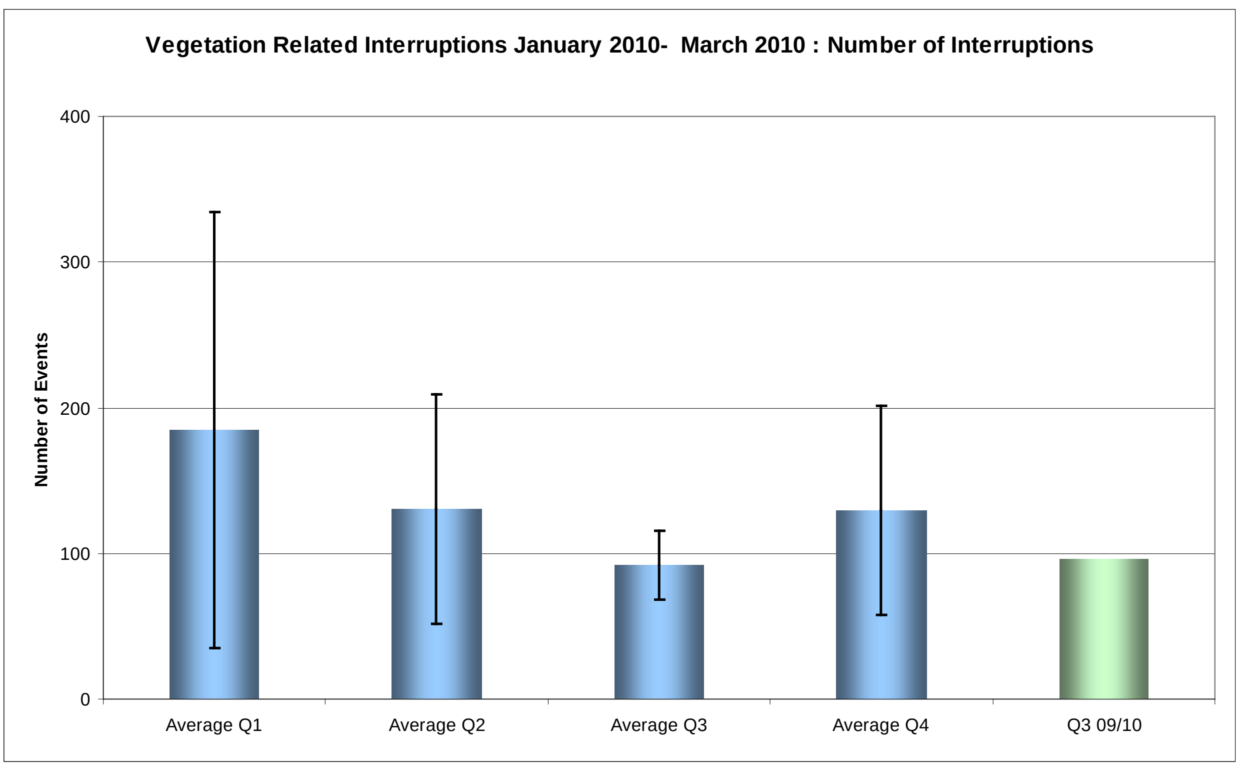

Figure 21: Number of Interruptions 1 January 2010 to 31 March 2010

3. CUSTOMER SERVICE

3.1. Management of Unplanned Interruptions

Aurora's 24-hours per day customer contact fault centre provides a continuous facility for customers to contact Aurora for fault and emergency situations. The Fault and Emergency Call Centre (Fault Centre) also dispatches field crews to attend on site, locate the fault, make repairs and restore supply. The Fault Centre receives information back from the field crews and records details regarding the fault, repairs undertaken and restoration details, enabling the Fault Centre operators to update customers and provide timely details affecting their supply.

The TVD Avalanche Trouble Call Management Suite (TVD) is the call management system that is used at the Fault Centre for dealing with fault and emergency calls. A feature of TVD is the ability to post recorded messages directly to the Telstra telephone exchange to manage inbound calls during outage situations. New messages can be updated and posted to the exchange in six seconds.

If a customer does not hear or understand the recorded message clearly (thus requiring more information) or the customer wishes to report new faults or additional information, calls are transferred through to our Fault Centre. This greatly increases the ability to quickly and effectively answer calls from many more customers during major faults.

A flowchart of the TVD system is shown in Figure 22 and includes calls volumes for this quarter for each stage of the process.

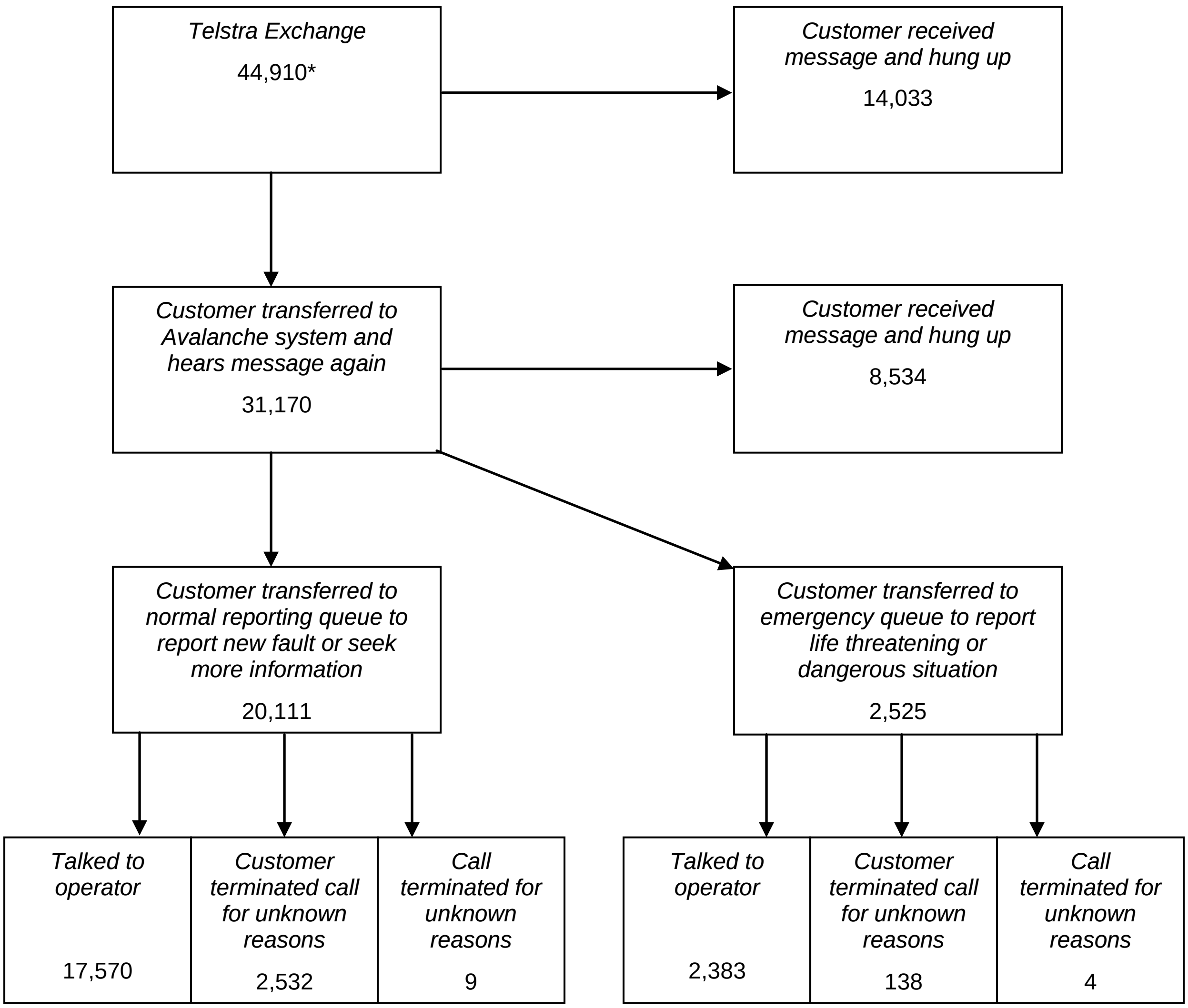

Figure 22: Fault Centre Calls –TVD Call Management System

NB The call volumes provided in the above table include calls from customers residing on King and Flinders Islands. This inclusion is occasioned by the fact that the TVD Call Management System is unable to breakdown the figures by region, and therefore we provide an inclusive total number of calls to the Telstra exchange also. This is the only instance in this report whereby data pertaining to customers of the Bass Strait Islands is included.

3.2. Complaints

Aurora continues to improve its complaints and claims handling process, including electronic data capture and reporting facilities within the supply quality and reliability areas. Dedicated officers focus on dealing with complaints and initiating investigations and, where appropriate, remedial work.

Complaints from customers relating to the reliability and quality of supply for the reporting period are shown in Table 7.

	Jan – Mar 2010
Total number quality and reliability of supply complaints	209
Complaints total as a percentage of the number of installations*	0.08%
**Number of installations at 30 September 2009: 276,866*	

Table 7: Number of customer complaints

3.3. Customer Charter Payments

Aurora's Electricity Distribution Customer Charter (Customer Charter) communicates Aurora's service guarantees to customers. Every customer service standard is aimed at ensuring that Aurora maintains high standards in delivering electricity to its customers. Some of the service standards are backed up by a guarantee, which means that if Aurora doesn't meet the standard then customers are able to claim a credit to their account within one month of the incident.

The breakdown of Customer Charter payments can be seen in Tables 8, 9 and 10. See page 14 for more details regarding Guaranteed Service Level payments.

3.3.1. New Connections and Reconnections

Aurora's guarantee for connections and reconnections is a $30 credit to the customer's electricity account for each business day late, up to a maximum of $150. Claims for new connections can be made when Aurora has failed to connect supply by the customer agreed date. Claims for reconnections may be made when Aurora has failed to reconnect supply within the next business day.

The breakdown of new connections and reconnections is shown in Table 8.

	Jan - Mar 2010
Total new connections	1,197
Total new connections completed by scheduled date	1,144
Total new connections where timeframe is negotiated	375
Percentage of connections where timeframe is negotiated	26.3%
Total Customer Charter Payments for new connections (number / $)	45 / $6,120
Total reconnections	4,069
Total reconnections completed by scheduled date	4,068
Total Customer Charter Payments for reconnections (number / $)	0 / $0

Table 8: Customer Charter Payments for Connections and Reconnections

3.3.2. Planned Interruptions

Where Aurora plans an interruption to the power supply, its reason, expected duration and general timing is provided to each affected customer in writing at least four business days prior to the interruption. Information is also given to customers on ways to best prepare for an interruption to their supply.

For outages at the transformer level and above, notification cards are automatically mailed out to customers. For smaller outages the traditional method of hand delivered notification cards is used. At times Aurora will also use forms of public media to supplement written notification.

If Aurora fails to notify affected customers of planned interruptions at least four business days prior to the interruption, customers are able to claim for a $30 credit to their electricity account.

Customer Charter payments due to customers not being notified of planned interruptions are shown in Table 9.

	Jan – Mar 2010
Total number of planned interruptions	813
Total Customer Charter Payments (number / $)	68 / $2,040

Table 9: Customer Charter Payments for Planned Outages

3.3.3. Street Lighting

Aurora's guarantee to customers is that any defective street lighting adjacent to that customer's home or business will be repaired within seven business days of notification of the fault. If the fault requires more than a lamp replacement, Aurora advises the customer on how long the repairs will take.

If a customer is the first person to report a street lighting outage and Aurora does not meet its seven business day guarantee, the customer is able to claim for a $30 credit to their electricity account for each day that Aurora is late, up to a maximum of $150.

Customer Charter payments due to street lighting repairs are shown in Table 10.

	Jan - Mar 2010
Total number of street lights (as at 31 Dec 2009)	47,651
Number of reported faults	553
Number repaired within 7 business days of fault being reported	484
Number not repaired within 7 business days of fault being reported	53
Number not repaired*	16
Total Customer Charter Payments (number / $)	3 / $330

Table 10: Customer Charter Payments for Street Lighting

** This is the number of street lighting faults reported during the Quarter but which had not been repaired come the end of the reporting period. The faults may or may not be repaired within 7 business days of being reported, and the corresponding data will be published in the ensuing Quarterly report.*

4. RELIABILITY IMPROVEMENT PROJECTS

The status of reliability improvement projects currently underway and planned is shown in Table 11.

Strategy	Year	Project	Status
Targeted Reliability Improvement Program	07/08	Burnie CBD	Complete
		Derby – Ringarooma	Complete
		Longford	Complete
		Perth	Complete
		Longford Rural	Complete
		Kings Meadows	Complete
		Devonport CBD	Complete
		Westbury	Complete
	08/09	Coles Bay / Bicheno Swansea	Complete
		Swansea	Complete
		Turner's Beach	Complete
		Somerset / Wynyard	Complete
		Dilston Windermere	Complete
		Sheffield	Complete
		Derby/Ringarooma Stage 2	Complete
		George Town	Complete
		Ulverstone	Complete
		Forrestier Peninsula	Ready for construction
		Pirates Bay/Nubeena/Port Arthur stage 1	Complete
		St Helens	Ready for construction
	09/10 - Proposed	North Coast	Feasibility study completed
		Burnie/Penguin	Feasibility study completed
		North West	Feasibility study completed

Strategy	Year	Project	Status
		Mid Tamar	Feasibility study completed
		Port Sorell	Feasibility study completed
		Queenstown	Feasibility study completed
		Cradle Coast	Feasibility study completed
		Winnaleah	Feasibility study completed
		Lewisham – Dodges Ferry	Feasibility study completed
		Pirates Bay/Nubeena/Port Arthur stage 2	Feasibility study completed
		Forrestier Peninsula – non critical vegetation	Feasibility study completed
	10/11-Proposed **List not complete	North East Rural	Not yet started
		Scottsdale	Not yet started
		Midway Point	Not yet started
		Oatlands	Not yet started
		Bridport	Not yet started
Reliability Analysis Improvements	07/08	Active Recloser List	Complete
		Protection	Design complete
		Customer	Complete
		Planned	Complete
	08/09	Protection Zone Analysis	G-technology complete. Protection Zones available.

Table 11: Current and future Reliability Improvement Projects

Approvals

Drafted	Technical Analyst		
Reviewed	Regulatory Analyst		
Reviewed	Regulation Manager		
Submitted	Technical Leader System Performance		
Recommended	Group Manager System and Asset Management		
Recommended	Group Manager Commercial Management		
Approved	General Manager Network		

Appendix A. Individual Community Performances

Colour	Meaning	Detail	
GREEN	***OK***	***average performing communities***	***(above the Average Reliability)***
BLUE	***OK***	***below average performing communities***	***(just below Average reliability)***
ORANGE	***NOT OK***	***low performing communities***	***(nearing the Lower Bound Limits)***
RED	***NOT OK***	***poor performing communities***	***(at or below the Lower Bound Limits)***

The Tasmanian Electricity Code - clause 8.6.11(a) 'Interruptions to supply', sets standards or limitations for the frequency and duration of interruptions to customers.

Performance levels, for this reporting period, have been measured against the new TEC standards.

The new standards for the average reliability and the lower bound of reliability, for each supply area category, are:

Community category	Lower bound of reliability per category		Lower bound of reliability per community	
	Annual number of supply interruptions	Annual total interruption time	Annual number of supply interruptions	Annual total interruption time
Critical Infrastructure	0.2	30	0.2	30
High Density Commercial	1	60	2	120
Urban	2	120	4	240
Higher Density Rural	4	480	6	600
Lower Density Rural	6	600	8	720

SAIFI Performance

Area Name	Area Class.	Tx in Area	Area Load (kVA)	Target Annual Freq.	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Hobart Critical Extended	Crit. Inf	89	115	0.20	**0.44**	**0.43**	**0.45**	**0.58**	**0.30**	**0.24**	0.19	0.07	0.07	0.07	0.16	0.17	0.20
Burnie CBD	HD Comm.	23	18	2.00	0.13	0.26	0.18	0.32	0.31	0.17	0.28	0.22	0.85	0.85	1.14	0.81	0.19
Devonport CBD	HD Comm.	11	8	2.00	**3.17**	**3.00**	**2.09**	0.43	0.43	0.43	1.40	1.23	1.66	1.66	0.72	0.69	0.22
Glenorchy Commercial	HD Comm.	9	11	2.00	0.41	0.55	0.48	0.55	0.34	0.20	0.20	0.07	0.14	0.14	0.14	0.91	0.41
Hobart	HD Comm.	44	40	2.00	0.73	0.99	0.95	1.11	0.53	0.32	0.27	0.08	0.20	0.20	0.44	0.43	0.43
Kings Meadows	HD Comm.	3	2	2.00	0.08	0.08	0.08	1.08	1.00	1.00	1.00	0.00	1.00	1.00	**2.08**	**2.08**	1.08
Kingston Commercial	HD Comm.	5	4	2.00	0.16	0.16	0.37	0.37	0.37	0.47	1.11	**2.32**	**2.32**	**2.32**	1.50	0.00	0.00
Launceston CBD	HD Comm.	33	34	2.00	0.02	0.11	0.17	0.26	0.73	0.75	0.69	0.59	0.17	0.17	0.21	0.21	0.53
Rosny Commercial	HD Comm.	10	9	2.00	0.25	0.50	0.75	0.75	0.75	0.55	0.80	1.05	0.80	0.80	0.52	0.52	0.64
Bridport	Urban	33	5	4.00	3.68	1.57	1.65	2.47	1.33	2.25	**5.23**	2.47	1.49	1.49	1.34	1.09	1.22
Brighton	Urban	30	5	4.00	0.62	0.28	0.26	0.87	1.96	1.94	1.81	2.26	2.32	2.32	**4.15**	3.24	3.12
Burnie - Penguin	Urban	388	96	4.00	1.14	1.45	1.43	1.69	1.97	1.54	2.57	2.15	2.15	2.15	1.69	2.31	2.17
Deloraine	Urban	50	11	4.00	2.63	1.28	1.68	1.64	2.02	2.02	2.11	3.11	1.93	1.93	3.35	**4.91**	**4.80**

Area Name	Area Class.	Tx in Area	Area Load (kVA)	Target Annual Freq.	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Devonport	Urban	352	122	4.00	2.17	1.83	1.35	0.74	0.66	0.42	1.08	1.44	1.54	1.54	0.87	0.72	0.61
George Town	Urban	60	16	4.00	1.38	1.72	1.71	3.22	3.59	3.12	2.17	1.47	1.01	1.01	0.93	3.56	3.31
Hadspen	Urban	24	5	4.00	0.35	0.24	0.17	0.43	0.47	0.47	0.26	1.39	1.39	1.39	2.62	1.23	1.68
Hobart Urban	Urban	1,828	652	4.00	1.24	0.92	0.91	0.94	0.84	0.85	0.93	0.87	0.80	0.80	0.78	0.81	0.92
Huonville	Urban	23	6	4.00	1.25	1.20	1.09	0.95	0.58	0.42	0.57	0.76	0.70	0.70	0.52	1.31	1.36
Kingston - Blackmans Bay	Urban	167	57	4.00	0.40	0.39	0.62	0.41	0.48	0.56	1.10	1.41	1.33	1.33	1.43	1.73	1.96
Latrobe	Urban	52	12	4.00	2.38	**6.28**	**6.28**	**6.36**	**4.45**	0.41	0.35	1.34	1.27	1.27	1.33	1.40	2.47
Launceston Urban	Urban	1,056	370	4.00	1.30	1.18	1.32	1.35	1.67	1.87	1.64	1.38	0.94	0.94	1.94	2.10	2.05
Lewisham - Dodges Ferry	Urban	88	10	4.00	0.38	1.43	1.41	1.45	1.83	0.84	1.83	1.82	2.46	2.46	1.27	2.21	1.25
Longford	Urban	47	10	4.00	**5.43**	3.88	2.29	3.21	2.80	2.80	2.12	2.54	2.27	2.27	2.48	1.66	2.34
Margate - Snug	Urban	104	18	4.00	0.27	0.30	0.82	0.83	1.06	1.10	0.91	1.00	0.78	0.78	1.04	1.85	2.32
Midway Point	Urban	18	4	4.00	1.09	0.88	0.31	0.27	1.27	1.39	1.25	1.29	0.69	0.69	1.38	1.31	0.92
New Norfolk	Urban	84	20	4.00	0.78	0.99	1.27	1.52	1.22	1.03	0.46	0.61	0.60	0.60	1.38	1.23	1.21
Perth	Urban	38	6	4.00	1.72	1.77	1.79	**4.74**	**4.11**	**4.03**	**4.11**	1.21	1.25	1.25	1.37	1.44	1.39
Port Sorell	Urban	49	11	4.00	0.57	1.87	1.69	2.82	3.71	2.45	3.51	**4.78**	**4.81**	**4.81**	**5.59**	3.25	2.25

Area Name	Area Class.	Tx in Area	Area Load (kVA)	Target Annual Freq.	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Queenstown	Urban	49	11	4.00	1.29	1.94	2.04	1.63	1.63	1.60	1.89	1.48	1.45	1.45	0.23	2.70	2.83
Rosebery	Urban	28	20	4.00	0.37	0.77	0.43	0.72	0.73	0.33	0.33	0.09	0.05	0.05	0.17	0.50	0.50
Scottsdale	Urban	31	9	4.00	1.07	0.08	0.10	0.62	1.63	1.75	1.67	1.31	0.45	0.45	0.46	0.74	0.62
Sheffield	Urban	21	4	4.00	**5.83**	**4.96**	**4.97**	2.04	1.13	1.21	1.52	1.48	1.56	1.56	1.31	1.39	2.56
Smithton	Urban	62	30	4.00	0.54	0.64	0.55	0.56	0.49	0.38	0.67	0.62	0.64	0.64	0.49	0.71	0.75
Somerset - Wynyard	Urban	132	35	4.00	**4.14**	**4.51**	3.93	**4.79**	**4.54**	3.00	**4.19**	3.46	2.75	2.75	2.82	3.49	3.06
Sorell	Urban	29	10	4.00	0.18	0.10	1.38	1.40	1.43	1.36	0.08	0.16	0.35	0.35	0.45	0.36	0.46
St Helens	Urban	39	7	4.00	**9.15**	**6.08**	**6.04**	**6.09**	1.15	2.19	2.29	1.24	2.26	2.26	1.43	1.72	0.72
Strahan	Urban	38	6	4.00	2.59	2.28	0.36	1.89	1.86	3.00	3.17	2.70	3.66	3.66	**5.40**	**5.86**	**5.92**
Tamar South	Urban	270	29	4.00	2.32	1.71	2.02	2.30	2.73	2.76	2.06	1.39	1.03	1.03	1.91	2.79	2.55
Turners Beach	Urban	55	8	4.00	1.65	2.52	2.74	2.91	2.86	1.56	2.35	3.30	3.35	3.35	3.52	3.82	2.85
Ulverstone	Urban	160	44	4.00	0.78	0.74	1.03	1.22	1.34	0.94	0.80	1.07	1.31	1.31	2.39	2.82	2.67
Westbury	Urban	30	8	4.00	2.84	1.07	1.17	1.17	1.15	1.15	0.20	0.20	0.20	0.20	1.11	2.64	2.16
Bicheno	HD Rural	38	6	6.00	**10.22**	**9.19**	**8.29**	**8.39**	2.42	3.58	3.38	2.26	2.20	2.20	1.27	1.28	1.24
Brighton Rural	HD Rural	244	22	6.00	1.41	1.16	0.79	0.87	1.18	0.83	0.83	1.16	1.11	1.11	2.69	2.36	2.77

Area Name	Area Class.	Tx in Area	Area Load (kVA)	Target Annual Freq.	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Campbell Town	HD Rural	38	4	6.00	4.52	4.60	4.33	2.26	2.33	1.35	0.39	0.43	1.50	1.50	3.39	3.63	2.37
Coal River Valley	HD Rural	144	10	6.00	1.98	2.35	2.80	2.92	3.46	2.99	3.20	3.12	2.03	2.03	1.15	1.35	1.63
Coles Bay	HD Rural	31	4	6.00	**13.04**	**13.14**	**12.15**	**11.31**	3.24	4.39	4.38	3.22	3.20	3.20	1.74	1.67	1.62
Copping - Dunalley	HD Rural	140	7	6.00	3.83	4.92	3.93	2.46	1.45	0.32	0.15	0.17	4.14	4.14	**6.96**	**7.73**	5.00
Cradle Coast	HD Rural	2,434	187	6.00	2.99	3.36	3.62	3.92	4.33	3.46	3.43	3.62	2.57	2.57	3.36	4.83	4.96
Derby - Ringarooma	HD Rural	175	11	6.00	2.36	1.51	2.21	4.54	4.12	4.06	3.19	1.50	1.23	1.23	3.16	4.67	3.91
Devon Hills-Evandale	HD Rural	213	26	6.00	1.35	1.53	1.44	3.98	4.21	3.85	3.98	1.33	1.21	1.21	1.84	1.86	1.94
Dilston - Windemere	HD Rural	46	2	6.00	**8.50**	**6.61**	5.05	5.62	**6.71**	**8.07**	**7.56**	5.22	2.74	2.74	4.36	3.91	4.86
Forcett - Dodges Ferry	HD Rural	110	4	6.00	1.75	1.70	1.86	1.37	0.88	1.05	1.40	1.15	2.35	2.35	1.99	3.50	2.35
Forestier Peninsula	HD Rural	107	4	6.00	4.34	4.27	3.63	4.28	3.95	3.51	3.30	2.04	3.32	3.32	4.28	**7.24**	5.87
Granton-Magra	HD Rural	212	16	6.00	1.08	1.59	2.01	1.74	1.75	1.13	0.61	0.61	0.72	0.72	1.04	1.66	1.64
Huon-Channel	HD Rural	959	62	6.00	2.36	2.03	2.33	2.11	1.63	1.77	2.10	2.42	1.93	1.93	1.91	3.54	3.80
Huonville - Cygnet	HD Rural	145	11	6.00	1.35	0.57	0.65	0.56	0.56	0.52	0.35	1.30	1.22	1.22	1.45	2.77	3.60

Area Name	Area Class.	Tx in Area	Area Load (kVA)	Target Annual Freq.	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Longford Rural	HD Rural	818	57	6.00	3.66	2.68	2.70	3.50	3.20	3.22	2.80	2.88	3.06	3.06	3.73	3.67	3.56
Meander Valley Rural	HD Rural	456	24	6.00	4.83	3.49	3.08	3.35	3.84	3.83	3.43	4.55	3.16	3.16	**6.31**	**8.69**	**8.36**
Mid-Tamar (Exeter etc)	HD Rural	126	5	6.00	2.17	3.26	3.68	3.53	5.44	4.14	4.85	4.21	2.55	2.55	1.81	**6.68**	5.64
Oatlands	HD Rural	13	2	6.00	5.68	**7.13**	5.66	3.96	2.75	1.36	2.76	5.62	**6.83**	**6.83**	**10.37**	**10.44**	**10.24**
Penna	HD Rural	72	4	6.00	0.90	0.97	0.97	0.84	1.01	0.90	1.19	1.11	1.49	1.49	1.52	1.95	1.12
Pirates Bay - Nubeena - Port Arthur	HD Rural	218	15	6.00	**7.46**	**8.24**	**6.18**	5.09	5.63	4.96	5.52	4.13	4.71	4.71	**9.50**	**11.24**	**9.64**
Primrose Sands	HD Rural	30	3	6.00	4.61	2.39	0.49	0.39	1.39	1.56	2.38	2.64	2.69	2.69	1.42	2.15	1.66
Scottsdale Rural	HD Rural	309	22	6.00	3.33	2.17	2.04	2.55	2.35	2.76	3.70	1.94	1.59	1.59	1.50	1.98	2.10
Smithton Rural	HD Rural	763	54	6.00	4.75	4.99	5.14	5.33	4.70	3.58	3.67	3.41	2.32	2.32	3.04	4.45	4.52
South Arm	HD Rural	414	20	6.00	1.39	1.38	1.57	2.20	2.56	2.59	2.80	2.12	1.17	1.17	1.96	2.53	3.05
St Marys	HD Rural	16	2	6.00	2.65	1.22	1.13	1.18	1.21	1.55	1.43	1.48	1.46	1.46	2.01	1.96	1.62
Swansea	HD Rural	24	5	6.00	2.67	3.69	3.52	1.47	1.29	3.54	5.53	**7.54**	**8.21**	**8.21**	5.35	5.71	4.62
Triabunna - Orford	HD Rural	95	11	6.00	0.88	1.36	1.90	1.78	2.21	1.32	0.88	1.92	1.53	1.53	2.77	3.24	3.14
Upper Tamar	HD Rural	59	17	6.00	3.41	3.51	3.60	4.23	**6.21**	5.78	4.67	4.36	4.04	4.04	4.79	3.08	2.56

Area Name	Area Class.	Tx in Area	Area Load (kVA)	Target Annual Freq.	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Wayatinah	HD Rural	5	2	6.00	4.00	2.00	2.13	1.54	1.54	1.54	0.13	0.92	0.92	0.92	0.80	0.23	0.23
West Huon River	HD Rural	259	23	6.00	1.40	1.02	1.28	1.05	1.01	0.95	0.71	0.70	0.52	0.52	0.71	1.70	1.70
Winnaleah	HD Rural	34	3	6.00	2.15	2.16	2.30	5.88	**7.39**	**8.01**	**7.57**	4.26	2.28	2.28	4.18	**6.33**	**7.36**
Zeehan	HD Rural	27	5	6.00	3.63	3.52	2.37	2.37	1.29	2.27	1.91	1.47	2.40	2.40	**9.12**	**11.54**	**9.82**
Bothwell Rural	LD Rural	145	6	8.00	4.74	5.18	6.73	3.65	4.15	3.20	1.65	1.98	1.50	1.50	**8.31**	**9.29**	**11.47**
Bruny Island Rural	LD Rural	264	9	8.00	3.15	3.34	3.60	3.90	2.64	4.31	2.69	2.42	2.42	2.42	1.19	5.21	7.05
Burnie Rural	LD Rural	707	31	8.00	3.68	3.94	4.04	4.02	4.59	4.84	3.81	4.73	3.89	3.89	5.17	7.04	6.99
Channel Rural	LD Rural	912	30	8.00	2.20	1.78	1.50	1.03	1.22	1.84	2.20	2.83	2.50	2.50	2.29	6.18	7.31
Coal Valley Rural	LD Rural	592	24	8.00	1.94	2.23	2.26	2.24	5.48	5.17	4.61	4.45	1.69	1.69	1.27	1.45	1.29
Cressy - Blessington Rural	LD Rural	907	50	8.00	4.94	4.34	3.57	3.60	4.19	4.62	4.27	5.02	4.72	4.72	6.52	5.86	6.09
Derwent Valley Rural	LD Rural	1,240	73	8.00	2.38	2.52	2.39	2.39	3.17	2.96	2.81	2.88	2.31	2.31	2.77	3.08	3.01
Dover Rural	LD Rural	328	20	8.00	1.32	0.97	1.24	1.58	0.95	0.95	1.28	1.63	1.76	1.76	2.52	2.25	2.07
Far North East Rural	LD Rural	361	20	8.00	5.73	4.60	5.01	**9.80**	**8.07**	**8.52**	**8.44**	3.91	3.29	3.29	4.40	6.33	5.70

Area Name	Area Class.	Tx in Area	Area Load (kVA)	Target Annual Freq.	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Fingal Valley Rural	LD Rural	350	28	8.00	3.55	3.97	4.40	4.38	4.79	3.91	3.34	2.82	2.47	2.47	3.12	4.69	5.48
George Town Industrial	LD Rural	81	41	8.00	0.20	0.16	0.72	1.90	2.79	3.20	2.96	2.74	2.02	2.02	1.76	0.95	1.19
Highlands	LD Rural	201	19	8.00	3.97	5.12	4.99	5.02	3.93	2.62	1.93	1.60	1.35	1.35	1.67	2.69	4.01
Huonville Rural	LD Rural	525	18	8.00	3.18	3.25	3.16	2.81	1.72	1.86	2.45	2.46	2.29	2.29	2.36	2.84	3.26
Kempton Rural	LD Rural	557	19	8.00	1.70	1.94	2.01	1.83	3.09	2.25	2.16	2.59	2.48	2.48	3.62	3.42	3.39
North Coast	LD Rural	420	15	8.00	3.86	4.21	5.78	6.79	6.94	7.09	5.60	5.98	5.11	5.11	5.06	**8.11**	6.80
North East Rural	LD Rural	1,070	47	8.00	4.73	2.87	3.06	6.16	6.63	6.92	**8.19**	4.30	3.54	3.54	3.85	5.26	6.02
North West	LD Rural	582	26	8.00	6.15	6.67	6.16	6.33	6.96	5.47	6.08	5.35	3.65	3.65	3.43	6.50	6.98
Oatlands - Buckland Rural	LD Rural	606	21	8.00	3.75	4.68	4.14	3.39	2.72	1.65	2.40	2.85	3.51	3.51	4.81	6.30	6.73
Railton Rural	LD Rural	1,773	95	8.00	4.66	4.22	4.34	3.25	2.86	2.62	2.30	3.37	2.52	2.52	3.71	5.87	6.09
Ross Rural	LD Rural	259	12	8.00	6.67	6.48	7.83	5.65	6.98	5.61	4.27	3.85	2.45	2.45	6.55	**8.27**	6.62
Sorell - Dunalley	LD Rural	339	11	8.00	4.27	3.81	3.25	2.27	0.99	1.15	1.30	0.98	2.44	2.44	3.27	5.10	3.25
St Helens Rural	LD Rural	418	24	8.00	7.09	5.09	4.94	5.58	2.80	3.47	3.38	1.97	1.65	1.65	1.32	1.57	1.21
Tamar East Rural	LD Rural	605	35	8.00	3.34	3.38	3.30	3.95	4.41	4.31	3.84	2.41	1.49	1.49	2.20	4.10	4.15

Area Name	Area Class.	Tx in Area	Area Load (kVA)	Target Annual Freq.	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Tamar West	LD Rural	989	42	8.00	1.90	3.09	3.27	4.39	5.92	4.64	3.94	3.43	2.97	2.97	3.85	4.83	4.68
Tasman Peninsula Rural	LD Rural	243	7	8.00	**9.46**	**9.84**	6.74	5.89	5.45	4.70	6.26	5.32	**8.57**	**8.57**	**10.09**	**14.54**	**13.06**
Triabunna - St Marys Rural	LD Rural	583	34	8.00	4.39	5.05	4.86	4.83	2.29	2.52	3.52	3.50	3.72	3.72	3.51	3.85	3.55
West Coast	LD Rural	130	36	8.00	1.36	1.34	1.20	1.57	1.64	1.62	1.41	0.77	0.97	0.97	1.91	2.46	2.32

SAIDI Performance

Area Name	Area Class.	Tx in area	Area Load (kVA)	Target Annual Duration	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Hobart Critical Extended	Crit. Infr.	89	115,250	30	21	26	**35**	**43**	28	20	14	12	13	**58**	**34**	**52**	**56**
Burnie CBD	HD Comm.	23	18,000	120	38	69	33	48	47	16	71	66	114	**137**	**124**	77	50
Devonport CBD	HD Comm.	11	8,750	120	**386**	**212**	**129**	20	20	20	35	73	**144**	**218**	**153**	114	32
Glenorchy Commercial	HD Comm.	9	11,000	120	37	40	30	18	9	7	4	2	19	40	17	83	45
Hobart	HD Comm.	44	40,200	120	40	59	58	86	54	41	38	9	20	35	77	76	85
Kings Meadows	HD Comm.	3	2,450	120	3	3	3	65	62	62	62	0	21	21	39	39	18

Area Name	Area Class.	Tx in area	Area Load (kVA)	Target Annual Duration	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Kingston Commercial	HD Comm.	5	4,750	120	36	36	54	54	52	84	34	195	168	396	156	0	0
Launceston CBD	HD Comm.	33	34,550	120	1	4	21	31	46	54	38	28	22	15	33	33	32
Rosny Commercial	HD Comm.	10	9,050	120	22	142	149	149	141	54	127	139	125	92	21	107	112
Bridport	Urban	33	5,404	240	207	120	129	169	111	100	508	543	140	113	213	127	156
Brighton	Urban	30	5,978	240	50	25	50	40	95	95	102	410	385	600	680	376	354
Burnie - Penguin	Urban	388	96,959	240	84	125	140	274	281	235	433	306	282	316	207	701	726
Deloraine	Urban	50	11,478	240	78	84	106	99	136	109	288	643	500	455	686	767	737
Devonport	Urban	352	122,752	240	160	181	121	91	111	74	171	267	251	291	168	122	110
George Town	Urban	60	16,063	240	73	139	163	305	299	207	185	113	105	234	85	219	235
Hadspen	Urban	24	5,543	240	39	16	21	45	58	58	24	173	173	247	262	89	378
Hobart Urban	Urban	1,828	652,186	240	85	88	102	119	121	116	148	139	131	143	119	134	153
Huonville	Urban	23	6,320	240	124	221	228	215	136	45	48	56	59	71	44	265	272
Kingston - Blackmans Bay	Urban	167	57,658	240	38	41	100	90	114	110	156	191	167	347	185	220	287
Latrobe	Urban	52	12,693	240	214	512	529	530	364	56	41	47	49	46	75	88	138
Launceston	Urban	1,056	370,360	240	122	122	164	179	203	206	196	158	110	207	216	232	225

Area Name	Area Class.	Tx in area	Area Load (kVA)	Target Annual Duration	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Urban																	
Lewisham - Dodges Ferry	Urban	88	10,441	240	33	**469**	**472**	**477**	**514**	119	**605**	**646**	**610**	**597**	91	93	82
Longford	Urban	47	10,740	240	**366**	**340**	**399**	**520**	**366**	**366**	**279**	**459**	**350**	**372**	**401**	131	164
Margate - Snug	Urban	104	18,126	240	42	47	67	61	69	66	146	150	165	**294**	135	**476**	**531**
Midway Point	Urban	18	4,815	240	106	81	23	44	137	143	140	120	78	80	**303**	**308**	**257**
New Norfolk	Urban	84	20,189	240	96	121	148	147	137	120	80	161	162	**386**	**365**	**241**	**263**
Perth	Urban	38	6,530	240	156	166	177	**311**	198	187	**334**	209	223	**281**	158	138	125
Port Sorell	Urban	49	11,303	240	103	**578**	**553**	**667**	**708**	**248**	**266**	**409**	**424**	**379**	**1491**	**867**	**782**
Queenstown	Urban	49	11,353	240	150	191	220	218	213	**253**	**417**	**331**	**329**	**240**	28	**298**	**333**
Rosebery	Urban	28	20,885	240	23	51	37	41	43	15	15	4	10	84	25	70	70
Scottsdale	Urban	31	9,018	240	26	7	8	98	193	215	**463**	**398**	**322**	68	81	102	73
Sheffield	Urban	21	4,540	240	**542**	**481**	**475**	202	**278**	**304**	**354**	**349**	117	109	79	96	165
Smithton	Urban	62	30,280	240	47	40	38	55	54	60	76	60	69	73	52	89	107
Somerset - Wynyard	Urban	132	35,110	240	199	**331**	**377**	**479**	**476**	**346**	**615**	**633**	**496**	**520**	**645**	**809**	**786**
Sorell	Urban	29	10,315	240	24	11	42	52	54	45	14	64	121	81	133	74	75

Area Name	Area Class.	Tx in area	Area Load (kVA)	Target Annual Duration	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
St Helens	Urban	39	7,575	240	**1042**	**1005**	**1228**	**1231**	**351**	**379**	**403**	40	137	115	133	182	103
Strahan	Urban	38	6,169	240	69	80	87	**247**	**241**	**270**	**261**	185	**847**	**1293**	**1186**	**1308**	**579**
Tamar South	Urban	270	29,154	240	202	199	**349**	**257**	**274**	**287**	182	163	192	**267**	234	**316**	**290**
Turners Beach	Urban	55	8,902	240	165	**330**	**358**	**367**	**341**	150	**805**	**1096**	**1101**	**1092**	**547**	**867**	**746**
Ulverstone	Urban	160	44,457	240	85	127	124	200	216	133	181	168	159	170	**396**	**559**	**576**
Westbury	Urban	30	8,040	240	161	34	18	19	15	14	15	30	30	206	49	**330**	182
Bicheno	HD Rural	38	6,343	600	**664**	**641**	543	**1360**	**907**	**1308**	**1275**	437	422	106	106	107	104
Brighton Rural	HD Rural	244	22,871	600	166	225	192	190	116	39	48	185	187	471	597	481	511
Campbell Town	HD Rural	38	4,991	600	456	378	207	155	163	145	31	33	87	583	**806**	**836**	**758**
Coal River Valley	HD Rural	144	10,413	600	158	152	219	231	243	226	365	351	269	193	62	180	247
Coles Bay	HD Rural	31	4,041	600	**1054**	**1079**	**1002**	**1725**	**960**	**1405**	**1383**	535	505	124	152	144	142
Copping - Dunalley	HD Rural	140	7,431	600	419	494	480	126	117	41	67	73	284	278	**606**	**819**	**646**
Cradle Coast	HD Rural	2,434	187,012	600	290	414	511	564	**666**	536	540	541	483	**795**	576	**1822**	**1830**
Derby - Ringarooma	HD Rural	175	11,810	600	276	217	133	**783**	**823**	**812**	567	254	190	408	536	**625**	555
Devon Hills- Evandale	HD Rural	213	26,113	600	38	82	110	250	254	220	464	326	343	377	162	158	178

Area Name	Area Class.	Tx in area	Area Load (kVA)	Target Annual Duration	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Dilston - Windemere	HD Rural	46	2,640	600	**812**	**806**	**714**	476	**823**	**1065**	**762**	570	461	**606**	597	557	**631**
Forcett - Dodges Ferry	HD Rural	110	4,660	600	189	187	279	283	197	208	413	342	364	346	85	226	192
Forestier Peninsula	HD Rural	107	4,102	600	416	505	417	375	389	284	**760**	**703**	**741**	**684**	416	478	496
Granton-Magra	HD Rural	212	16,619	600	145	203	216	160	170	108	66	103	123	258	298	326	333
Huon-Channel	HD Rural	959	62,810	600	274	288	333	291	178	144	318	394	373	**633**	310	**802**	**790**
Huonville - Cygnet	HD Rural	145	11,097	600	132	86	95	86	82	68	57	132	119	256	204	**794**	**915**
Longford Rural	HD Rural	818	57,098	600	250	232	250	315	355	376	370	422	397	516	513	560	457
Meander Valley Rural	HD Rural	456	24,919	600	269	269	265	367	448	425	515	**796**	**658**	**838**	**1166**	**1490**	**1434**
Mid-Tamar (Exeter etc)	HD Rural	126	5,328	600	336	411	579	488	**834**	**770**	**780**	**613**	194	479	289	**926**	**818**
Oatlands	HD Rural	13	2,905	600	299	415	355	424	344	229	407	446	530	**651**	**826**	**874**	**747**
Penna	HD Rural	72	4,035	600	137	130	134	88	96	92	384	354	334	339	104	136	113
Pirates Bay - Nubeena - Port Arthur	HD Rural	218	15,148	600	**649**	**736**	**635**	384	427	384	**680**	**652**	**629**	**656**	**956**	**1370**	**1285**
Primrose Sands	HD Rural	30	3,925	600	453	278	74	48	141	219	**678**	**721**	**671**	576	92	92	138

Area Name	Area Class.	Tx in area	Area Load (kVA)	Target Annual Duration	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Scottsdale Rural	HD Rural	309	22,264	600	293	216	227	333	327	366	470	200	125	146	203	264	297
Smithton Rural	HD Rural	763	54,602	600	449	531	**717**	**758**	**750**	**687**	522	473	324	**614**	525	**868**	**868**
South Arm	HD Rural	414	20,101	600	210	211	237	455	395	390	**603**	370	293	237	284	**611**	**614**
St Marys	HD Rural	16	2,078	600	178	238	201	200	149	53	34	52	35	125	287	281	301
Swansea	HD Rural	24	5,000	600	309	399	380	174	118	475	495	552	515	**614**	155	247	393
Triabunna - Orford	HD Rural	95	11,066	600	37	111	144	139	451	385	354	381	64	60	338	**681**	**673**
Upper Tamar	HD Rural	59	17,726	600	247	322	408	323	583	566	478	520	422	452	597	324	165
Wayatinah	HD Rural	5	2,075	600	463	396	562	238	238	238	48	200	200	297	173	30	30
West Huon River	HD Rural	259	23,756	600	112	123	152	123	111	91	70	77	74	138	68	330	343
Winnaleah	HD Rural	34	3,032	600	245	244	214	292	434	534	545	405	240	129	**921**	**1320**	**1571**
Zeehan	HD Rural	27	5,325	600	305	304	397	249	227	282	93	110	118	**640**	**844**	**1130**	**1165**
Bothwell Rural	LD Rural	145	6,252	720	**722**	**904**	**1144**	614	612	377	269	298	294	**1238**	**1634**	**1921**	**2523**
Bruny Island Rural	LD Rural	264	9,136	720	376	426	601	695	377	**803**	403	329	330	**1123**	505	**2491**	**2605**
Burnie Rural	LD Rural	707	31,320	720	448	545	**722**	630	655	640	410	650	639	**1142**	**865**	**4438**	**4375**
Channel Rural	LD Rural	912	30,196	720	323	277	230	169	193	276	391	431	399	461	290	**2301**	**2389**

Area Name	Area Class.	Tx in area	Area Load (kVA)	Target Annual Duration	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Coal Valley Rural	LD Rural	592	24,887	720	267	309	315	248	360	317	446	457	261	307	103	232	232
Cressy - Blessington Rural	LD Rural	907	50,368	720	383	377	398	402	470	686	608	**859**	**812**	**1098**	**1217**	**1330**	**1087**
Derwent Valley Rural	LD Rural	1,240	73,744	720	337	450	419	551	616	497	512	391	402	553	598	**753**	**733**
Dover Rural	LD Rural	328	20,059	720	128	127	214	265	204	207	283	299	332	282	209	254	202
Far North East Rural	LD Rural	361	20,820	720	560	513	664	**1608**	**1431**	**1454**	**1477**	636	476	**727**	663	**944**	**897**
Fingal Valley Rural	LD Rural	350	28,463	720	524	646	508	575	653	567	591	547	456	615	**780**	**1061**	**1138**
George Town Industrial	LD Rural	81	41,565	720	17	28	48	85	208	285	410	602	354	359	289	67	127
Highlands	LD Rural	201	19,086	720	605	**807**	**839**	**909**	719	532	382	285	282	690	390	**755**	**918**
Huonville Rural	LD Rural	525	18,827	720	522	639	685	666	432	339	547	511	477	704	407	620	683
Kempton Rural	LD Rural	557	19,658	720	161	356	369	330	355	167	176	346	321	**740**	707	662	627
North Coast	LD Rural	420	15,807	720	425	471	**1086**	**1106**	**1137**	**1338**	**722**	**935**	**876**	**1228**	574	**4096**	**4041**
North East Rural	LD Rural	1,070	47,169	720	392	192	285	**972**	**1142**	**1228**	**1463**	670	500	519	637	703	**762**
North West	LD Rural	582	26,866	720	644	**854**	**905**	**950**	**1209**	**1088**	**1042**	**889**	615	**764**	**755**	**2377**	**2560**
Oatlands -	LD Rural	606	21,093	720	255	267	267	253	171	104	255	254	272	443	487	**746**	**804**

Area Name	Area Class.	Tx in area	Area Load (kVA)	Target Annual Duration	Q3 05/06 - Q2 06/07	Q4 05/06 - Q3 06/07	Q1 06/07 - Q4 06/07	Q2 06/07 - Q1 07/08	Q3 06/07 - Q2 07/08	Q4 06/07 - Q3 07/08	Q1 07/08 - Q4 07/08	Q2 07/08 - Q1 08/09	Q3 07/08 Q2 08/09	Q4 07/08 - Q3 08/09	Q1 08/09 - Q4 08/09	Q2 08/09 - Q1 09/10	Q3 08/09 Q2 09/10
Buckland Rural																	
Railton Rural	LD Rural	1,773	95,166	720	487	485	515	457	435	418	403	501	428	668	703	**1956**	**1980**
Ross Rural	LD Rural	259	12,496	720	630	625	544	529	537	513	**763**	577	314	**1031**	**1571**	**1673**	**1518**
Sorell - Dunalley	LD Rural	339	11,892	720	449	447	434	401	270	269	332	173	244	189	228	448	352
St Helens Rural	LD Rural	418	24,687	720	**801**	**813**	**955**	**1065**	496	482	512	137	99	275	188	209	241
Tamar East Rural	LD Rural	605	35,125	720	423	454	472	525	513	529	539	344	222	447	303	619	591
Tamar West	LD Rural	989	42,376	720	147	311	444	548	677	517	443	360	263	380	404	502	589
Tasman Peninsula Rural	LD Rural	243	7,453	720	**760**	**810**	599	532	543	490	**1461**	**1820**	**2102**	**1947**	**1638**	**2182**	**2240**
Triabunna - St Marys Rural	LD Rural	583	34,672	720	239	455	439	**729**	656	617	605	313	308	244	211	288	408
West Coast	LD Rural	130	36,307	720	215	260	255	643	668	641	641	210	297	365	373	517	417

Appendix B – Poor Performing Communities

Area Name	Area Classification	Area Load (kVA)	Community Frequency of Interruptions	Community Target Annual Frequency	Community Duration of Interruptions	Community Target Annual Duration	Planned Actions*
Hobart Critical Extended	Crit. Infr.	119,010	0.20	0.2	**56**	30	Hobart CBD Translay protection upgrade project to be completed over 3 years from 2009/10
Brighton	Urban	6,773	3.12	4	**354**	240	Install additional switchgear in 2009/10 to improve feeder redundancy.
Burnie - Penguin	Urban	100,564	2.17	4	**726**	240	TRIP to be completed in 2009/10
Deloraine	Urban	11,878	**4.80**	4	**737**	240	TRIP in planning for 2010/11
Hadspen	Urban	5,543	1.68	4	**378**	240	TRIP in planning for 2010/11
Huonville	Urban	6,420	1.36	4	**272**	240	Impacted by severe storm events, no action planned
Kingston - Blackmans Bay	Urban	61,574	1.96	4	**287**	240	No Action Planned
Margate - Snug	Urban	18,579	2.32	4	**531**	240	Impacted by severe storm events, no action planned
Midway Point	Urban	4,815	0.92	4	**257**	240	TRIP under investigation for 2011/12
New Norfolk	Urban	20,552	1.21	4	**263**	240	TRIP in planning for 2010/11
Port Sorell	Urban	11,253	2.25	4	**782**	240	TRIP to be completed in 2009/10
Queenstown	Urban	11,405	2.83	4	**333**	240	TRIP under construction in 2009/10
Somerset - Wynyard	Urban	41,895	3.06	4	**786**	240	TRIP completed in June 2009, impacted by severe storm events in Q1 2009/10

Area Name	Area Classification	Area Load (kVA)	Community Frequency of Interruptions	Community Target Annual Frequency	Community Duration of Interruptions	Community Target Annual Duration	Planned Actions*
Strahan	Urban	6,547	**5.92**	4	**579**	240	TRIP in planning for 2010/11
Tamar South	Urban	32,010	2.55	4	**290**	240	Impacted by severe storm events, no action planned
Turners Beach	Urban	8,927	2.85	4	**746**	240	TRIP completed in 2008/09
Ulverstone	Urban	45,942	2.67	4	**576**	240	TRIP completed in 2008/09
Campbell Town	HD Rural	5,206	2.37	6	**758**	600	TRIP in planning for 2010/11
Copping - Dunalley	HD Rural	7,719	5.00	6	**646**	600	Impacted by severe storm events, TRIP under investigation
Cradle Coast	HD Rural	171,089	4.96	6	**1830**	600	TRIP to be completed in 2009/10
Dilston - Windemere	HD Rural	2,690	4.86	6	**631**	600	TRIP completed in 2008/09
Huon-Channel	HD Rural	66,522	3.80	6	**790**	600	Impacted by severe storm events, Protection Upgrade and Vegetation clearing planned
Huonville - Cygnet	HD Rural	12,338	3.60	6	**915**	600	Impacted by severe storm events, no action planned
Meander Valley Rural	HD Rural	29,213	**8.36**	6	**1434**	600	TRIP in planning for 2010/11
Mid-Tamar (Exeter etc)	HD Rural	5,554	5.64	6	**818**	600	TRIP under construction in 2009/10
Oatlands	HD Rural	2,955	**10.24**	6	**747**	600	TRIP in planning for 2010/11

Area Name	Area Classification	Area Load (kVA)	Community Frequency of Interruptions	Community Target Annual Frequency	Community Duration of Interruptions	Community Target Annual Duration	Planned Actions*
Pirates Bay - Nubeena - Port Arthur	HD Rural	15,740	**9.64**	6	**1285**	600	TRIP completed in 2008/09, will continue in 2009/10
Smithton Rural	HD Rural	63,223	4.52	6	**868**	600	Impacted by severe storm events, no action planned
South Arm	HD Rural	20,562	3.05	6	**614**	600	Impacted by severe storm events, no action planned
Triabunna - Orford	HD Rural	11,114	3.14	6	**673**	600	Impacted by severe storm events, no action planned
Winnaleah	HD Rural	3,158	**7.36**	6	**1571**	600	TRIP to be completed in 2009/10
Zeehan	HD Rural	5,375	**9.82**	6	**1165**	600	No Action Planned
Bothwell Rural	LD Rural	6,458	**11.47**	8	**2523**	720	TRIP in planning for 2010/11
Bruny Island Rural	LD Rural	9,587	7.05	8	**2605**	720	Impacted by severe storm events, no action planned
Burnie Rural	LD Rural	31,100	6.99	8	**4375**	720	TRIP in planning for 2010/11, impacted by severe storm event
Channel Rural	LD Rural	32,085	7.31	8	**2389**	720	Impacted by severe storm events, no action planned
Cressy - Blessington Rural	LD Rural	58,539	6.09	8	**1087**	720	TRIP in planning for 2010/11
Derwent Valley Rural	LD Rural	76,976	3.01	8	**733**	720	Impacted by severe storm events, no action planned
Far North East Rural	LD Rural	21,165	5.70	8	**897**	720	TRIP completed on part of Far North East Rural in 2007/08, further action being investigated

Area Name	Area Classification	Area Load (kVA)	Community Frequency of Interruptions	Community Target Annual Frequency	Community Duration of Interruptions	Community Target Annual Duration	Planned Actions*
Fingal Valley Rural	LD Rural	29,918	5.48	8	**1138**	720	Impacted by severe storm events, no action planned
Highlands	LD Rural	19,927	4.01	8	**918**	720	Impacted by severe storm events, no action planned
North Coast	LD Rural	16,623	6.80	8	**4041**	720	TRIP to be completed in 2009/10, impacted by severe storm events
North East Rural	LD Rural	49,497	6.02	8	**762**	720	TRIP to be completed in 2009/10
North West	LD Rural	28,889	6.98	8	**2560**	720	TRIP to be completed in 2009/10, impacted by severe storm events
Oatlands - Buckland Rural	LD Rural	21,801	6.73	8	**804**	720	TRIP planned for 2010/11 in conjuntion with Oatlands Urban TRIP
Railton Rural	LD Rural	81,440	6.09	8	**1980**	720	TRIP under investigation for 2011/12, impacted by severe storm event
Ross Rural	LD Rural	13,430	6.62	8	**1518**	720	TRIP in planning for 2010/11, in conjunction with Campbell Town TRIP
Tasman Peninsula Rural	LD Rural	7,401	**13.06**	8	**2240**	720	TRIP completed in 2008/09, will continue in 2009/10

*NB Previous appendices of this format contained a column listing reasons as to why a community is poor performing. However, it was found that the information in this column was misleading as the performance is based on a rolling twelve-month data set. Thus, it has been excluded from this quarterly report and will continue to be excluded until the annual report.