Office of the Tasmanian Energy Regulator

Aurora Energy

Office of Energy Planning and Conservation

Joint Working Group Final Report

Distribution Network Reliability Standards

Volume II – Appendices

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PROJECT BRIEF

June 2006

Tasmanian Distribution Network Performance Requirements

Background

In setting price controls for a monopoly service provider, there is a concern that the entity may reduce costs (and thus increase profits) at the expense of service quality. To prevent this behaviour, regulators may link price with service quality by, amongst other approaches, requiring average and minimum standards of service.

Aurora Energy is the monopoly provider of electricity distribution network services in mainland Tasmania and, as such, it is regulated by the Regulator. The Regulator's objectives are set out in the *Electricity Supply Industry Act 1995* (ESI Act). They include "to promote efficiency and competition in the electricity supply industry" and "to protect the interest of consumers of electricity". The Act also requires that the Regulator must not unfairly discriminate between electricity entities, customers for electricity or other persons. Under Tasmania's policy of uniform electricity distribution charges for small customers, there is an equitable balance such that urban consumers do not unduly subsidise consumers in higher cost supply areas (e.g. remote rural) to the same level of reliability. In determining network performance requirements, there may be broader community and social objectives that the community considers should be taken into account.

At present the legislation charges the Regulator with the responsibility for determining reliability standards, but this may change if Government intends to specify reliability requirements for the State. Whether performance standards are ultimately set by Government, for example through Regulations, or by the Regulator through the 2007 Determination of maximum prices for electricity distribution services, a similar process will be required to establish those standards. The Regulator's setting of performance requirements will be bounded by the specific requirements of the ESI Act in regard to his functions, powers and duties of administrative fairness. The Government's setting of Regulations, while bounded by the scope and purpose of the Act, may adopt a broader set of public purpose objectives.

The Role of the Working Group

The role of the working group is to develop a proposal for consideration by the Regulator in consultation with advisory bodies, including the Reliability and Network Planning Panel, and interested parties.

Composition of the Working Group

The outcomes of the project will impact on electricity users, through price and standards of reliability, and on the broader economy. The principal stakeholders are thus Government, in regard to community interests, Aurora Energy Pty Ltd as the owner of the distribution network, and the Regulator as the person responsible under the ESI Act to protect the interests of consumers of electricity and to determine maximum prices. The working group will comprise:

- Chairman –appointed by the Regulator in consultation with the Director Energy Planning and
- Government appointees (2) - to confirm State infrastructure requirements;
- Aurora Energy (2) – to provide data of historic performance, network development planning and projected performance, incremental costs for improvements of reliability;
- Regulator (2) – project design and consistency with the Tasmanian Regulatory Framework.

Current Performance Requirements

Requirements for distribution network performance in Tasmania are currently set in three ways:

- by supply area categories[17] through the Tasmanian Electricity Code (TEC);
- by State-wide averages through the 2003 Pricing Determination (the Determination sets target levels of State-wide average reliability with financial penalties and bonuses for variations from the targets); and
- by minimum individual customer performance (Guaranteed Service Levels (GSL)), determined by the Regulator and given expression in Aurora's Customer Charter.

The present approach reflects limitations in the previously available data. It was impossible to accurately ascertain the level of service delivered to the individual customer. Performance data was available for feeders, and it was on this basis that performance standards were originally set. It is generally accepted that various areas of the State will have different performance outcomes due to the length of feeders

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[17] These categories being CBD, Urban and Other.

and the terrain through which feeders cross. Thus the performance of feeders supplying the central business districts of Hobart and Launceston were expected to be better than the performance of feeders supplying rural Tasmania. The introduction of the GSL scheme was recognition of the fact that while the average performance of a feeder could be adequate, some customers could experience very poor service.

The Regulator is concerned that while incentives may encourage improvements in average performance, there is a risk that performance measures, if focussed on average performance, may neglect addressing priority supply areas and customers experiencing very poor performance. Thus the Regulator is seeking a set of performance measures and standards that will reflect priorities for network reliability, including average performance measures for particular regions, in addition to measures and targets for individual customers.

Project Scope

The performance requirements will be the parameters on which Aurora will prepare or revise Asset Management Plans which will be the basis of the Aurora submission to the 2007 Investigation, leading to the Determination of Maximum Prices for electricity distribution services. The costs of achieving the reliability standards will be reviewed by the Regulator as part of the Investigation. Further, the Regulator will establish the performance incentive regime, including penalty and incentive rates, as part of the Determination. Thus it is important that network performance objectives are capable of being translated into measures and standards for quantitative reporting and for financial incentives.

Terms of Reference

The working group is to develop a draft set of performance categories and associated performance targets for the distribution network on mainland Tasmania.

The working group should:

(1) Establish an analytical method for determining the boundaries of geographic regions that may have different performance standards from neighbouring regions. It is desirable that the same definitions of regions will be used for the individual customer performance (GSL scheme) and for use in the incentive part of the Pricing Determination. The working group should not be constrained to using feeders to define regions. Nevertheless, feeder performance will continue to be measured for comparative performance monitoring. The regions should take account of demographics; ie the number and nature of the customers, an assessment of the value of reliability to the customers, the relative size of customer loads, contribution to the State economy and strategic significance. The number of regions should be kept to a workable size.

It may be desirable but not essential to match regions to pre-existing geographic boundaries such as census districts, postcodes, municipal boundaries, land use zones etc.

(2) Group the regions into a small number of categories (suggested no more than five). For example, each region could be categorised as either CBD, urban, rural or remote.

(3) Develop a set of performance measures; some suitable for groups of customers and some suitable for measuring the performance experienced by an individual customer. The measures for groups of customers should include SAIDI and SAIFI. The group should also consider whether MAIFI is appropriate to include in the performance measures[18]. Performance standards for individual customers should be expressed in terms of the number of outages per year and the duration of an individual outage (as currently defined in the GSL scheme). While the performance measures for individuals and groups will be separate, they are correlated and consistency between them is required.

(4) Develop performance targets for each category as well as a minimum acceptable performance level. The minimum acceptable performance level will be that level at which, if not met by any region in the category, the Regulator would expect immediate attention. The working group will also need to set the minimum acceptable level of performance for individual users in each category which will be used in the GSL scheme.

(5) The working group should take into account:

(a) the historical performance for the region and category ;

(b) the new performance standards for a region should not be worse than the historical performance standards;

(c) the importance of reliability for each category taking account of the economic impact of outages on those customers and the Tasmanian economy;

(d) the comparative reliability performance for each of the categories in Tasmania and in other jurisdictions within Australia with similar economic characteristics;

(e) the cost of upgrading the network (or of other strategies) to meet higher targets of reliability for particular regions;

(f) information from surveys in Tasmania and in other States of customer's willingness to pay for higher reliability of supply;

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[18] The working group is also invited to propose variations on the present 12 month rolling average for reporting SAIDI and SAIFI if the working group considers such a change has significant benefits.

(g) the ability of customers, as individuals or collectively, to negotiate premium quality supply or arrange their own supply security;

(h) the policy that the distribution tariff for small customers (those supplied at low voltage) belonging to a particular class on mainland Tasmania is to be uniform, regardless of where in mainland Tasmania that customer is supplied with electricity;

(i) how exclusions (for example Major Event Days) will be incorporated into the proposal;

(j) how changes in expectations over the 5 year period commencing January 2008 will affect the performance measures (the performance standards will be incorporated into the next Determination and will have a life of up to 5 years from 1 January 2008. It is thus necessary to include in the performance standards any predictable changes in expectations over that period as far as possible);

(k) the 2020 Aurora network planning horizon

(l) current practice in Tasmania and in other jurisdictions (particularly Victoria and South Australia).

(m) that the scheme should not be overly complex.

(6) The working group will need to ascertain the 'gap' between the present expected network performance and the proposed performance levels. From this gap it will be necessary for Aurora to estimate the cost of bridging the gap. Should the costs be considered by the working group to be unjustifiable then the working group should revise the proposed performance levels/boundaries or categorisation of the region(s) in question. The basis for the working group's proposals, including the principles on which the proposal is based should be documented. The group should also recommend whether a transition strategy is required to maintain continuity of data for trend analysis (especially where it applies to the present TEC standards).

(7) The working group is requested to develop performance standards for the distribution network. Customers may also experience loss of supply through failures of the transmission network and from other third party causes.

Timetable

A proposal is to be presented to the Regulator by mid August 2006, in anticipation for the Regulator to advise Aurora of target categories and reliability improvement priorities by end October 2006, to inform the Aurora submission to the 2007 Determination of prices for electricity distribution services.

The Chair is to advise the Regulator of key milestones and targets within 3 weeks of establishment of the working group.

APPENDIX B – METHODOLOGY

Defining Regions

Area Categories

The working group considered that five community categories should be defined:

- Critical Infrastructure – an area of concentrated critical infrastructure where a network solution for enhanced reliability is an efficient solution;
- High Density Commercial – areas of high annual consumption coinciding with the CBDs of the State's cities;
- Urban and Regional Centres – a city, town or other urban centre with annual electricity consumption at or higher than the electricity consumption density within the existing urban areas under the GSL scheme;
- Higher Density Rural – higher consumption rural areas and low-density peri-urban areas; and
- Lower Density Rural – the remaining regions of the State.

Choice of Data

The terms of reference stipulate that the regions should take account of demographics; ie the number and nature of the customers, an assessment of the value of reliability to the customers, the relative size of customer loads, contribution to the State economy and strategic significance.

The proposed regions have been classified based on electricity consumption density per unit area. The ability of Aurora Energy to relate sales data to connection points within its geographical information system (GIS) has enabled this approach. In taking this approach, the working group has assumed that in areas where electricity use is higher, reliability will consequently have a higher value. The working group noted that, in reality, the value of reliability is highly variable within areas, between different consumers and even between times of day.

The working group examined a number of measures by which regions might be classified according to their value of reliability. Land use and land value data was considered and the views of DED sought as to industries that might have a high value of reliability. Geographically related data from the State Infrastructure Planning System (SIPS) was obtained from DIER, including built-up areas, planning schemes, land use and the location of key community facilities (such as medical centres, emergency services and educational institutions).

The subjectivity involved in turning this material into a rigorous basis on which to define regions decided the working group against this approach. The volume of information, together with the generally dispersed nature of various commercial and agricultural activities and facilities, made handling the data almost impossible. Further, the pursuit of these options so far as they were completed tended to confirm, rather than supplement, the validity of electricity consumption density as the best proxy for value of reliability.[19] Thus, electricity consumption density represents a compromise proxy for value of reliability that is manageable, generally applicable and meaningful.

The working group adopted the position that distribution standards exist for the protection of customers who receive supply from a monopoly provider, and who are not in a position to negotiate the level of service required, as they would be able to in a competitive market. Very large customers, who receive a dedicated supply, command sufficient authority to negotiate their own reliability standards directly with the DNSP, and are supplied separately from the general distribution network in any event. As such, the consumption of customers who take supply directly from the transmission system or via a dedicated feeder in the distribution system has been excluded when deriving region boundaries.

The consumption of larger customers embedded in the distribution network is included in the consumption density calculation. Concentrations of high consumption activity can thus determine the overall classification of a region, which is an appropriate and desirable outcome, given the likelihood that the value of reliability, and the broader economic cost of outages, is higher for these customers.

To assist in the classification and definition of areas, Aurora Energy undertook vector and raster geographic analysis of electrical energy consumption for its customer installations. This information was mapped to land parcel information provided by the Department of Primary Industries and Water.

Table B.1: Data sources for spatial analysis

Dataset	Description	Source
Electricity consumption	2000-05 electrical energy consumption data by installation and tariff	Aurora's billing system
Address points	Address points generated from DPIW's statewide cadastral database, dataset 2004, second set	DPIW
Grid cells	500m x 500m square vector cells used for vector analysis of consumption data	Aurora
Background data	Geographical and topographical background to maps	The LIST www.thelist.tas.gov.au

[19] The working group notes that, having established the functionality of the GIS approach to setting distribution standards, refinements able to better capture the value of reliability could be made in future. The possibility of weighting consumption data according to the distribution tariff under which energy was supplied might be such a refinement, if suitable relativities between the tariffs could be found to reflect differing utilities.

The spatial analysis component of this study was undertaken using Intergraph Corporation's GeoMedia Professional and GeoMedia Grid Geographic Information System (GIS) applications. Information was obtained from the sources presented in Table B.1.

Mapping Electricity Consumption

The working group used two approaches to map electricity consumption, a conventional grid square (vector) summation of electricity use per unit area, and a smoothed contour spatial relationship (raster) between proximate points of consumption. The vector map was used as a high-level indicator of where high consumption localities were sited, while the raster map was used for detailed determination of boundaries. The methodology used to establish the two electricity consumption density maps is outlined below.

Building the grid square (vector) consumption density map

The following methodology was used by Aurora Energy to establish the vector map of consumption density:

(1) acquired annual average electricity consumption (last five years of consumption) by installation identifier and tariff from Aurora's billing system;

(2) aggregated electricity consumption to installations to give total electricity use per annum (kWh) for each installation;

(3) joined aggregated electricity consumption data to spatial address points joining map features to electricity consumption data on installation identifier (Figure B.1);

(4) created new address point/electricity consumption dataset;

(5) created 500m square vector regions (cells) (Figure B.2);

(6) performed spatial aggregation of sum of electricity consumption for address point electricity consumption data to cells; and

(7) created new cell/electricity consumption static dataset and thematically mapped cell/electricity consumption by custom electricity ranges (Figure B.3 and Figure B.4).

Figure B.1. Map of electrical installations, Midway Point, 1:15000 (*actual value not shown)

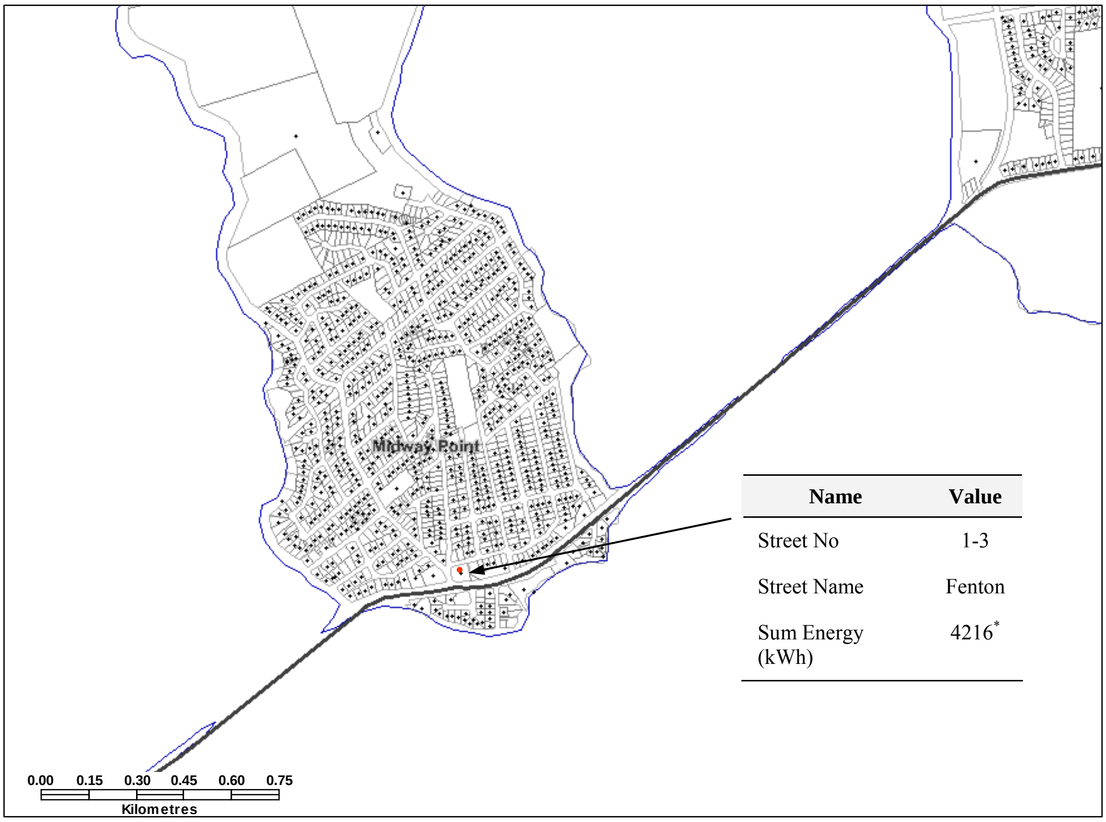


Figure B.2 Vector grid, Midway Point, 1:15000

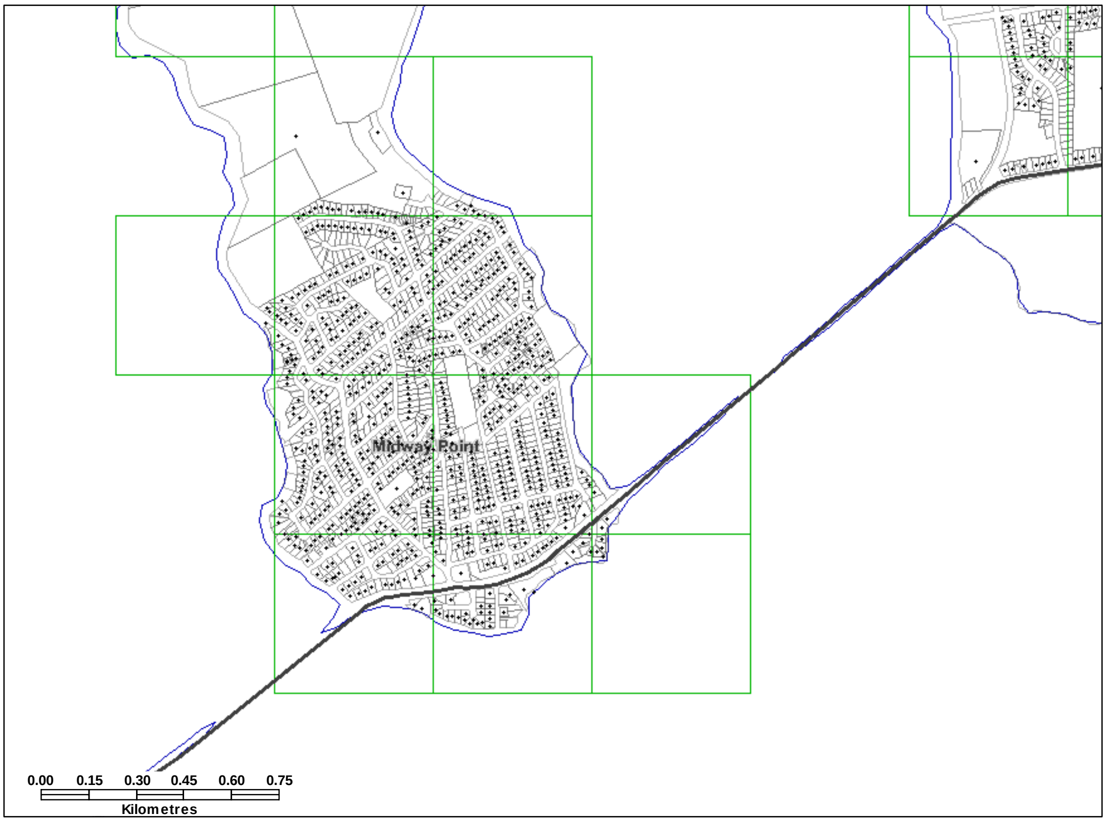


Figure B.3. Vector consumption density map, Midway Point, 1:15000

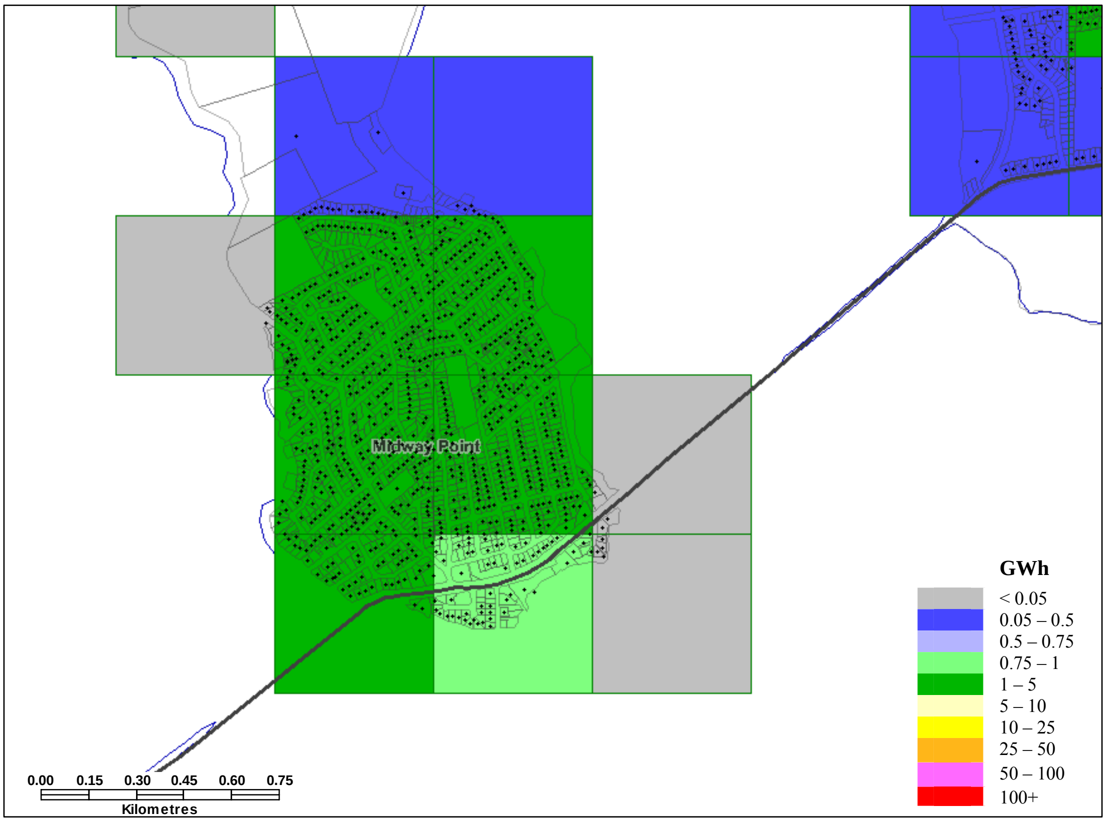
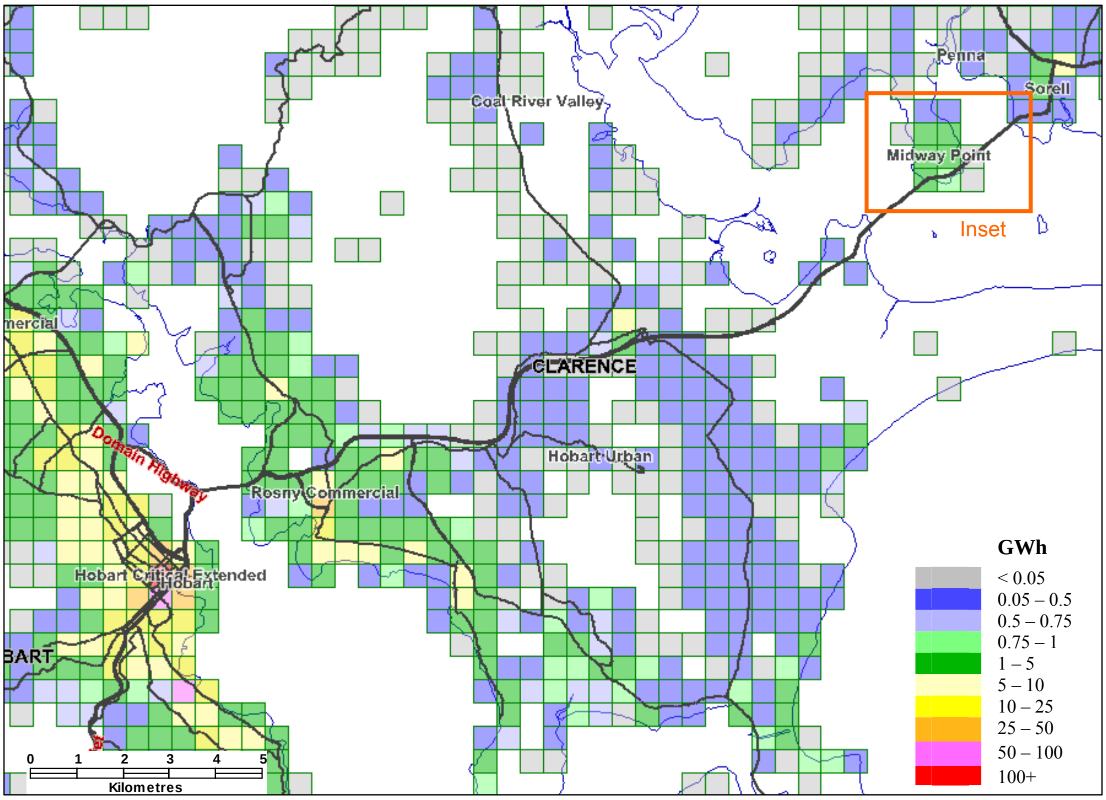


Figure B.4. Vector consumption density map, Greater Hobart, 1:100000



Building the smoothed contour (raster) consumption density map

The following methodology was used by Aurora Energy to establish the raster map of consumption density:

(1) obtained address point/electricity consumption dataset, as per steps 1-4 of the methodology for the vector map outlined above;

(2) weighted each address point relative to proximate consumption;

(3) calculated weighted consumption for each address point; and

(4) created new raster electricity consumption static dataset and thematically mapped weighted consumption by custom electricity ranges (Figure B.5 and Figure B.6).

Figure B.5. Raster consumption density map, Midway Point, 1:15000

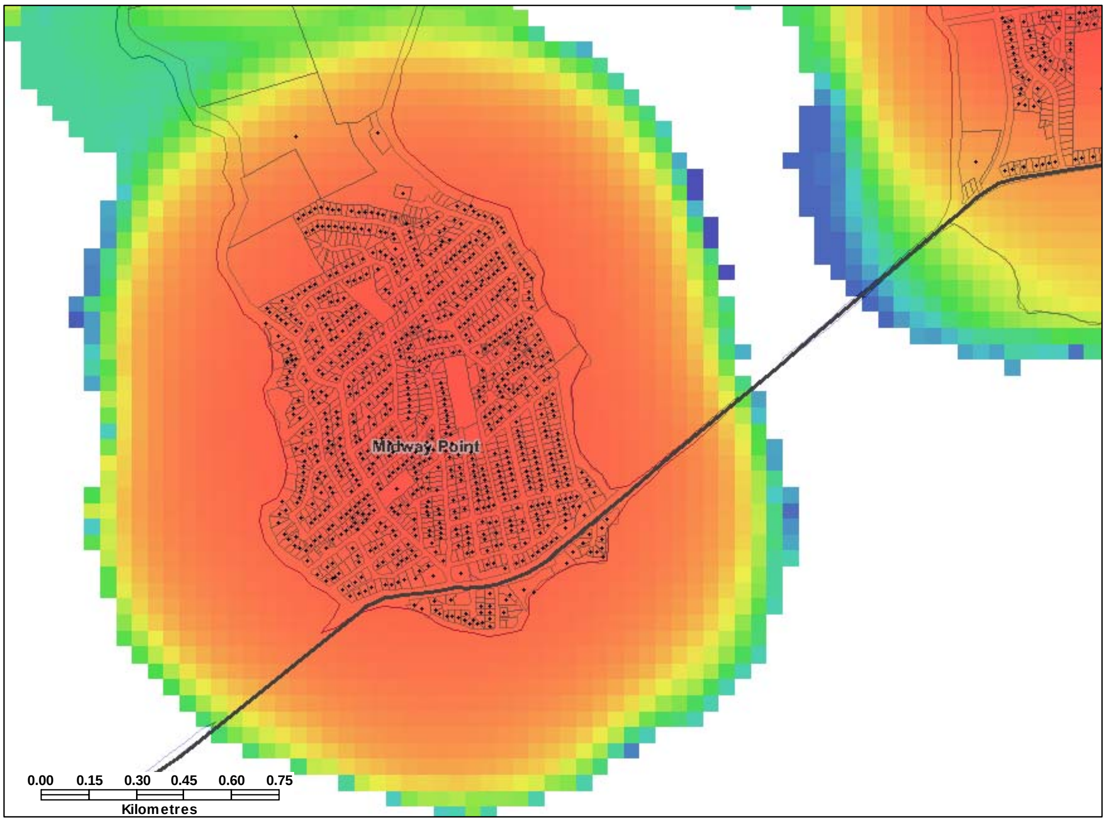
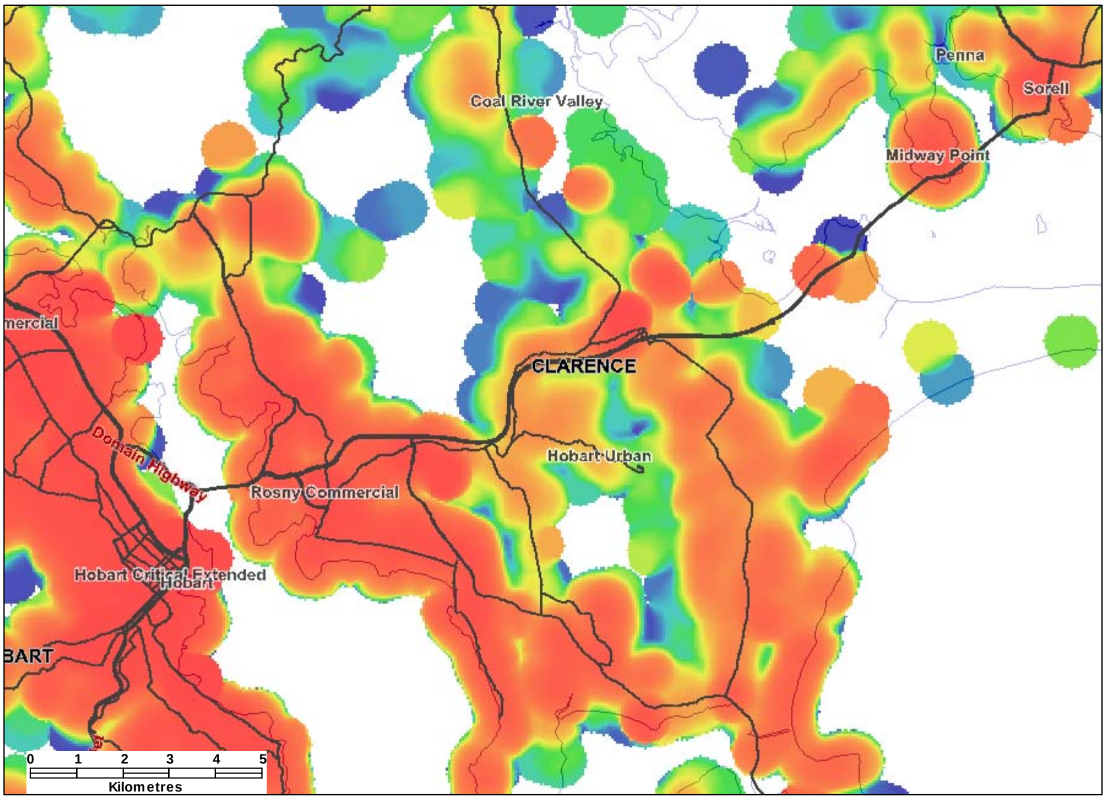


Figure B.6. Raster consumption density map, Greater Hobart, 1:100000



Defining Areas

The criteria and consumption thresholds used to derive region boundaries and classifications from the electricity consumption density maps are outlined below.

Urban areas

Candidate urban areas were identified from the vector map where:

(1) closely grouped cells had electricity consumption > 0.75 GWh per cell (set to match the existing urban boundary under the GSL scheme, Figure B.7);

(2) property parcel and electrical installation density in these areas confirmed:

(i) a town of regional significance exists, and

(ii) a concentration of high-density property parcels exist (Figure B.8).

This process identified communities where electricity consumption density matched or exceeded that found within the existing GSL urban category. Having identified these areas, Aurora Energy then manually digitised boundaries around high-density land parcels using cadastre or logical boundaries such as highways, major arterial roads or drainage features (Figure B.9). This process defined discrete regions that could be described in terms of a set of attributes, such as number of customers and average annual consumption. Boundaries were verified by reference to the raster map (Figure B.10). In general, urban boundaries are readily identifiable from the limits of housing sub-divisions.

From this list of candidate areas, communities were defined as urban where average annual total electricity consumption was found to be greater than 6 GWh.

Figure B.7. Identifying Urban consumption, North Coast, 1:150000

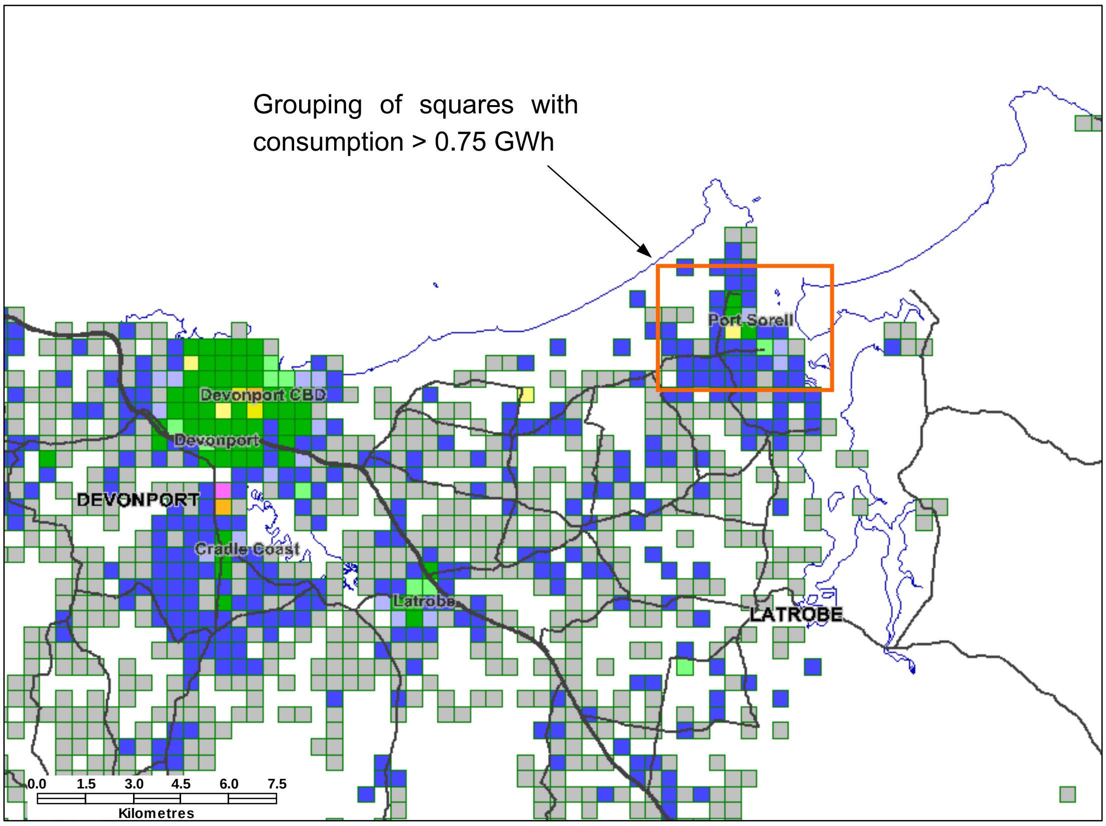


Figure B.8. Property parcels and installations, Port Sorell, 1:40000

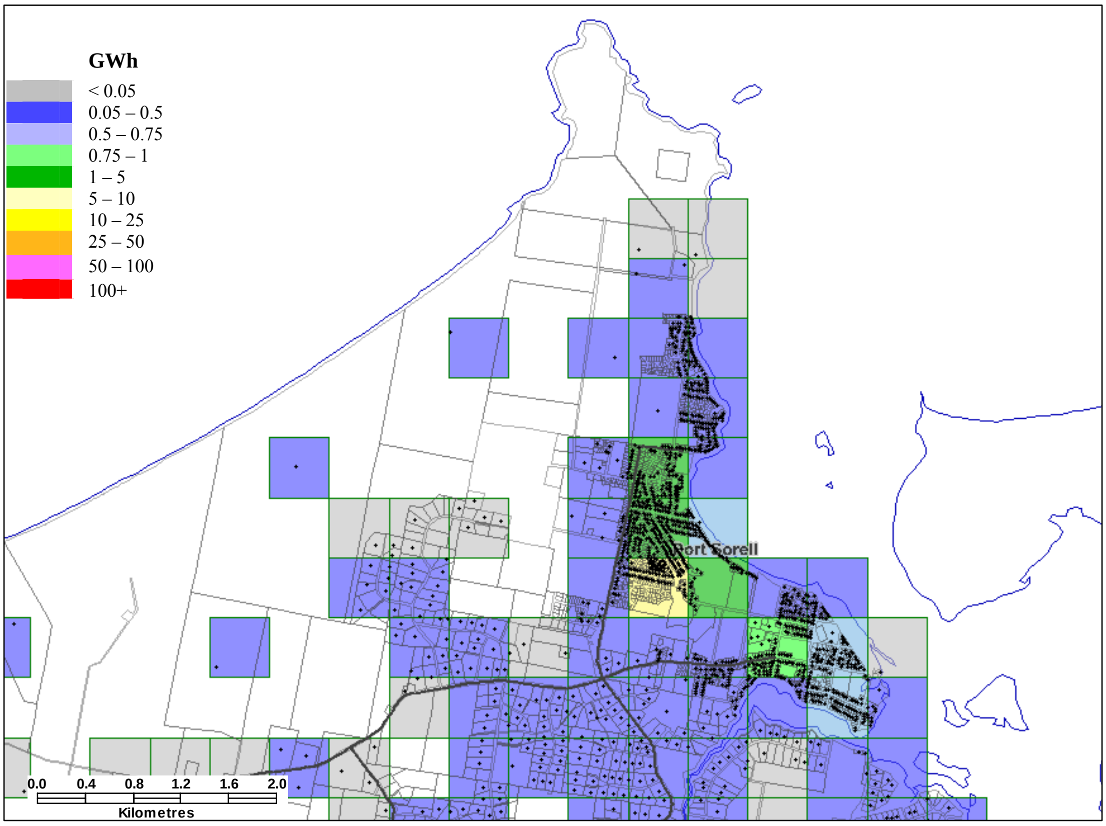


Figure B.9. Urban boundary, Port Sorell, 1:40000

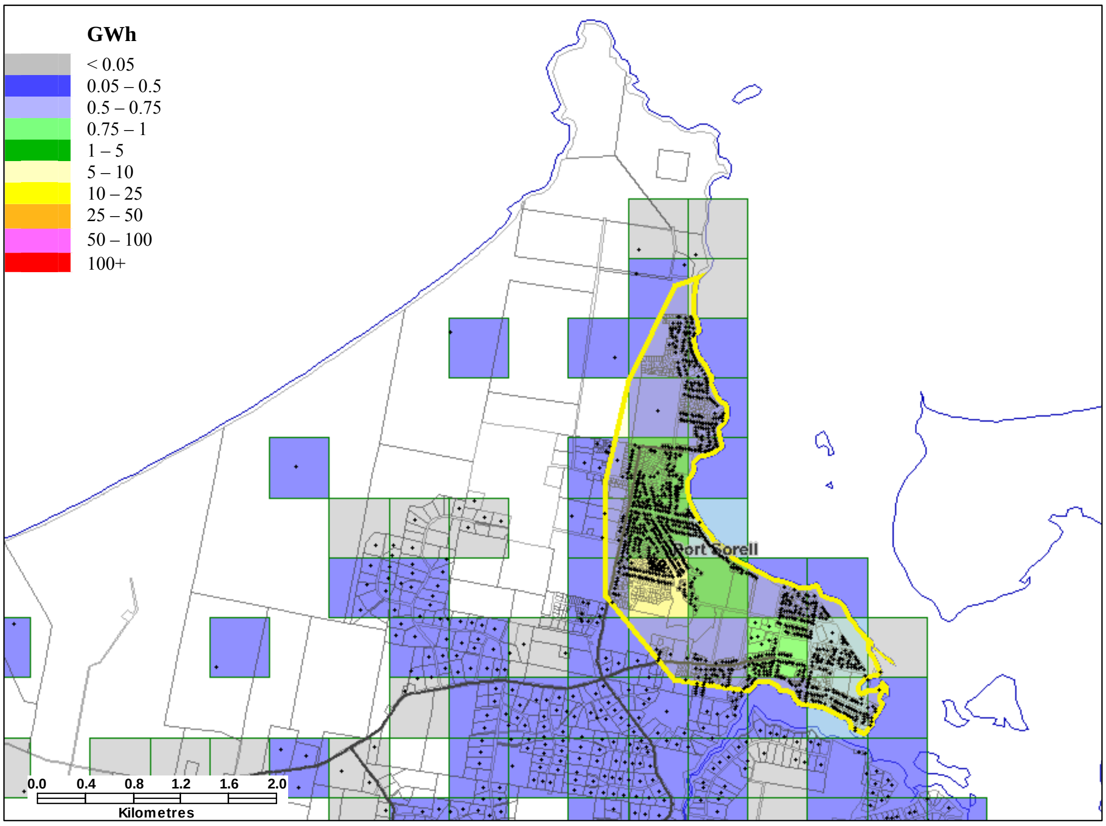
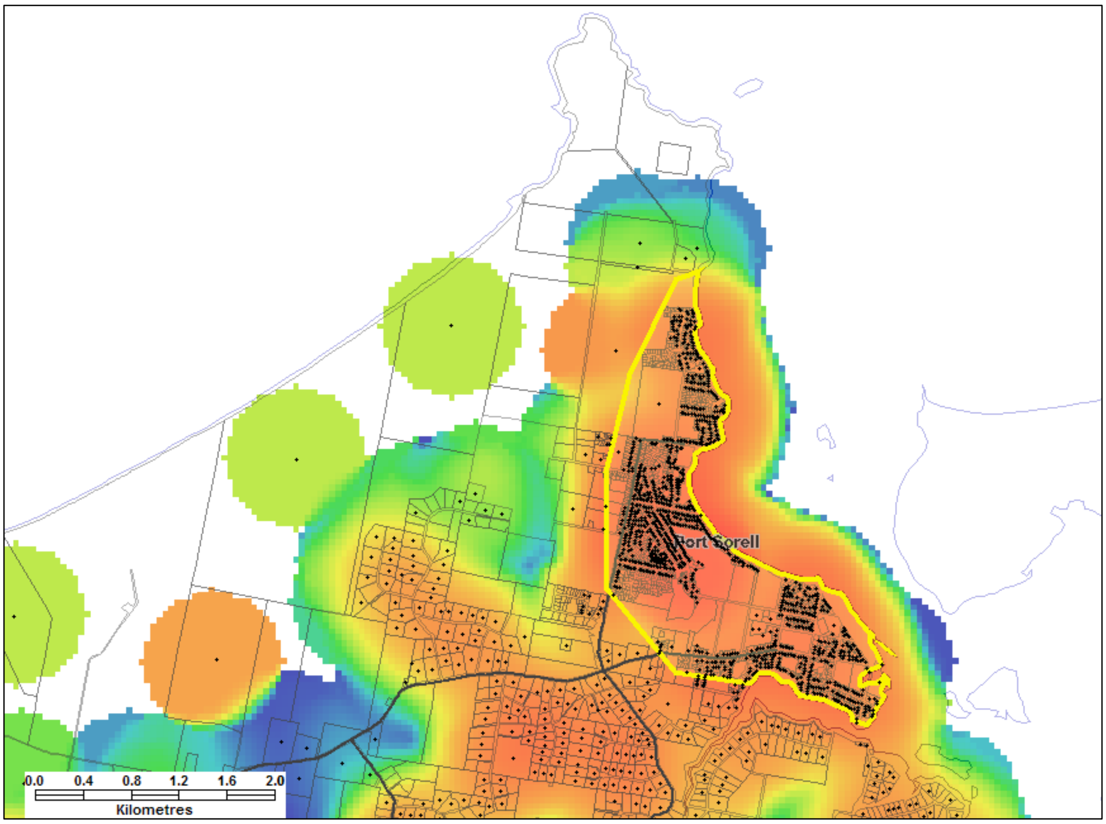


Figure B.10. Using the raster map to confirm boundary, Port Sorell, 1:40000



Higher Density Rural areas

The working group considered that two types of areas might present as candidate Higher Density Rural areas: semi-urbanised rural residential areas and areas of high-consumption agricultural activity.

The following methodology was used to identify candidate Higher Density Rural areas:

(1) identified areas of higher electricity consumption compared to the surrounding area outside defined urban areas and where significant rural centres are located, using the smoothed contour (raster) map;

(2) considered urban fringes where rural residential properties are contained in planning scheme (West Tamar was used as the benchmark to define a consumption threshold, using same approach as the existing GSL boundary for Urban, Figure B.11);

(3) manually digitised boundaries to encompass low-density development around peri-urban areas or regional towns (eg Campbell Town, Figure B.12).

Figure B.11. West Tamar Higher Density Rural defined via the raster map, Tamar, 1:80000

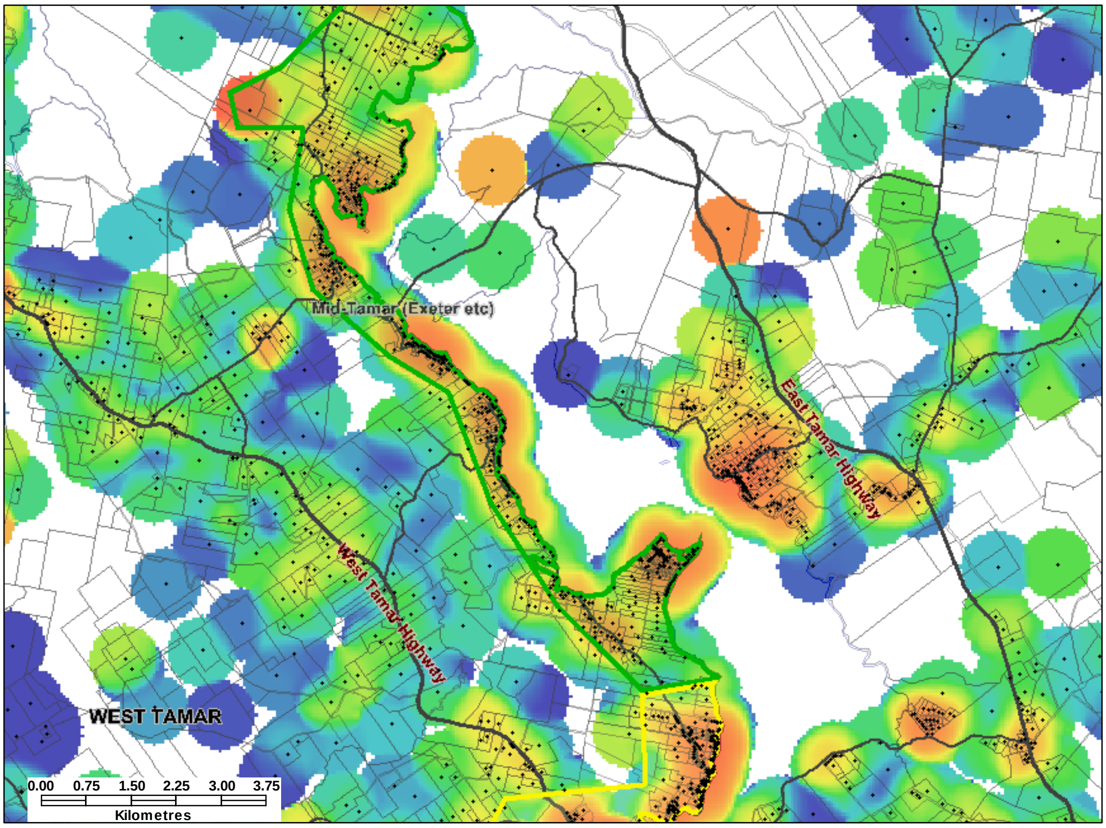
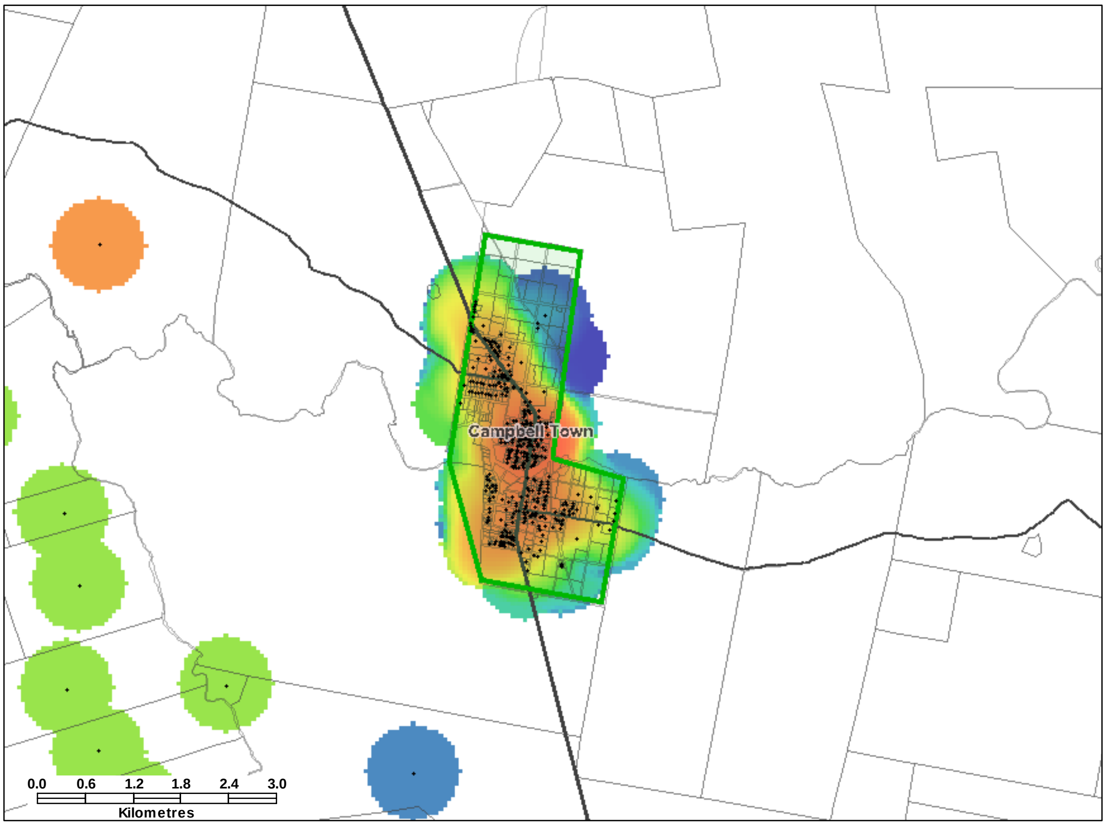


Figure B.12. Regional centre Higher Density Rural, Campbell Town, 1:60000



This process outlined candidate Higher Density Rural areas. Given that these boundaries did not necessarily conform to land parcel boundaries (as was the case for Urban regions) and that the total size of regions was highly varied, two threshold criteria were established to define Higher Density Rural regions:

- where the candidate area has average annual electricity consumption greater than 1. 5 GWh (and the area is a defined built-up area, such as a rural town, that did not have sufficient annual consumption to qualify as Urban); and
- where the candidate area has average annual electricity consumption per unit line length greater than 0.1 GWh/km (and the area is predominantly non-urban; consumption per unit line length used to account for variable region size).

Aurora Energy then expanded Higher Density Rural corridors between adjacent Higher Density Rural areas where appropriate.

Lower Density Rural areas

Lower Density Rural is classed as those areas not meeting "Urban and Regional Centres", "High-Value Commercial" or "Higher Density Rural" criteria. For the purposes of identifying localised reliability and for use in network planning, Aurora Energy created 27 Lower Density Rural regions, with boundaries based on network service areas and logical divisions within the existing distribution system.

High Density Commercial areas

The following methodology was used to determine High Density Commercial areas:

(1) identified CBD and significant commercial districts using electricity consumption data from the vector map (locations with consumption greater than 100 GWh/km^2, expressed as 25 GWh aggregated on the ½ km square grid);

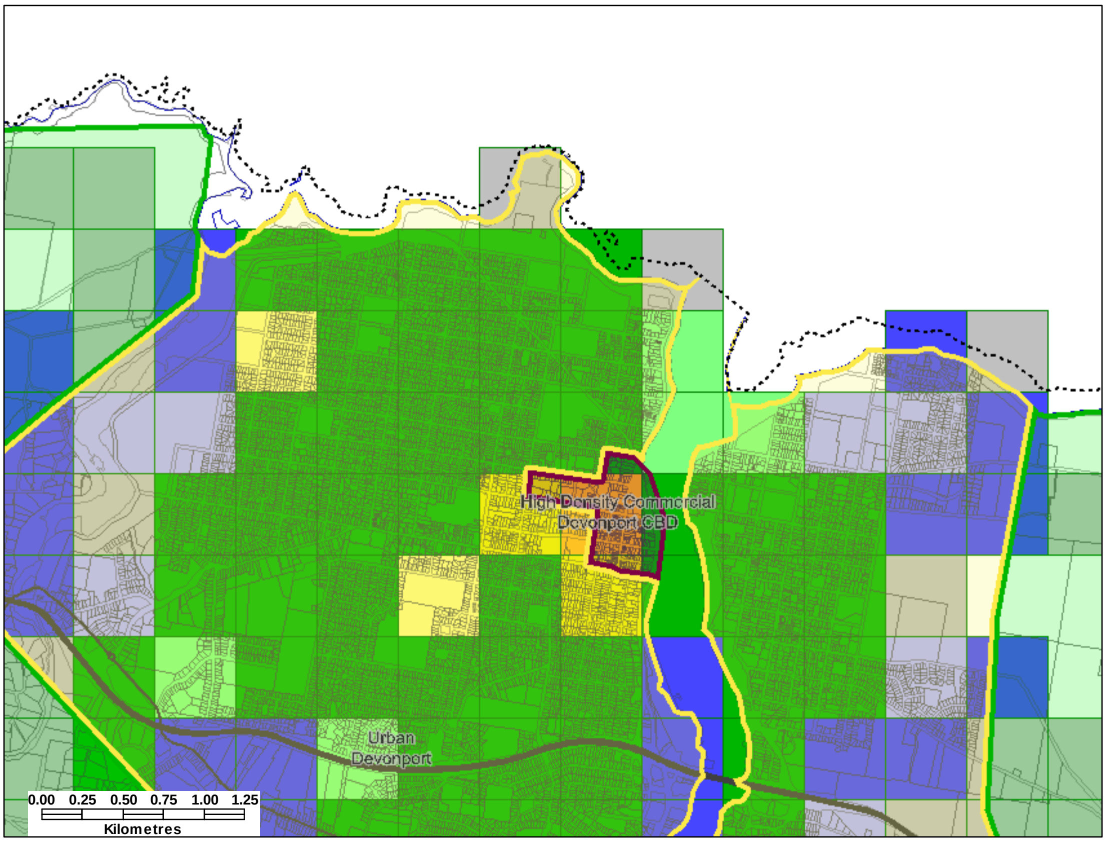
(2) defined boundaries based on Tasmanian Towns Street Atlas Edition 7 "City Centre" enlargements for Hobart, Launceston, Burnie, Devonport, Glenorchy and Rosny (Figure B.13);

(3) defined boundaries around other areas of intensive commercial activity at Kingston and Kings Meadows;

(4) manually digitised boundaries to contain Commercial properties or aligned boundaries to logical features such highways, major arterial roads or drainage features; and

(5) confirmed boundaries with local planning bodies.

Figure B.13. Grid square with consumption > 25 GWh, Devonport, 1:30000



Critical Infrastructure area

The working group defined an area where a concentration of critical infrastructure makes it appropriate to provide a higher level of reliability and security as a network solution. The working group noted that security of supply is generally most efficiently supplied to critical point loads through emergency generation, and that a concentration of such critical loads is required before a network solution becomes efficient in this regard. A concentration of critical loads was identified in Hobart.

Defining Measures and Targets

As outlined in section 3.1 above, the terms of reference require that the working group consider the following reliability measures in designing a new framework:

- System Average Interruption Frequency Index (SAIFI);
- System Average Interruption Duration Index (SAIDI);
- Momentary Average Interruption Frequency Index (MAIFI); and
- minimum individual customer reliability indices (GSL levels).

The terms of reference mandate the inclusion of SAIFI, SAIDI and GSL standards for individual areas. The working group's approach to implementing each of these measures is outlined below.

System Average Interruption Frequency Index (SAIFI)

SAIFI is a measure of the average number of outages experienced per customer per year in a given region, and is defined in Appendix D. However, Aurora Energy's reliability data allows it to record outage incidents at the individual customer level; that is, it is possible to determine the number of outages any individual customer has experienced in a defined period. Given this, it is possible to aggregate customers and number of outages at either the individual community or area category levels. Moreover, provided that the area under consideration is small enough, there is no numerical difference between the SAIFI of the area and the actual number of outages. In consequence, for simplicity of calculation and understanding, it was decided to consider the actual number of outages.

Two standards were established for each area classification, being an annual outage count for the classification, and a minimum annual outage count for each area within the classification. Standards were set for outages on high voltage distribution feeders (11kV and 22kV).

The annual outage count standard for all customers within a given classification was established by finding the average of this measure over the last five years (individual financial years 2001-02 to 2005-06) and rounding to the nearest half-integer.

The minimum annual outage count standard of any individual area within a classification was nominally set at twice the category average. This standard was then adjusted down, in the case of the Rural classifications, for two reasons: first, doubling the category average produced a minimum standard that was worse than the existing TEC standard; and second, to provide a true target for Aurora, rather than a standard that could be met with little effort. In the case of the Critical Infrastructure classification, with only one defined area, the statewide and classification average will be the same. The working group would consider that remedial action should be taken in any area being non-compliant in consecutive years.

System Average Interruption Duration Index (SAIDI)

SAIDI is a measure of the average duration of outages experienced per customer per year in a given region, and is defined in Appendix D. Like SAIFI, SAIDI is an average measure that can hide extreme performance. Also, like SAIFI, provided that the area under consideration is small enough, there is no numerical difference between the SAIDI of the area and the actual cumulative outage duration. Again, for simplicity, it was decided to consider the actual cumulative outage duration.

Unlike outage counts, Aurora Energy's reliability data system has only allowed it to record outage durations at the individual transformer level for the most recent financial year (2005-06). Prior to this, all transformers affected by an outage were ascribed an outage duration equal to the time required to restore the last transformer in an outage, rather than the actual time off supply.[20] Bearing this in mind, the working group used the historical, feeder level data, to set the cumulative outage duration standards and, to allow appropriate comparison, proposes that reporting against these outage standards be made using similar, feeder level data. The working group intends the cumulative outage duration measures to be established for reporting purposes only.

Nonetheless, the working group considers that reliability standards and measures that most accurately reflect customer experience are preferable, and recommends that Aurora move towards data collection processes that allow cumulative outage duration to be determined at a customer level. When an appropriate data set at this level is collected, the working group notes that the methodology applied to obtain the current cumulative outage duration targets may be applied to the customer-level data set to provide customer cumulative outage duration targets.

As with the outage count standards, two cumulative outage duration standards were established for each area category: an annual cumulative outage duration for the classification, and a minimum annual cumulative outage duration for each area within the classification. Standards were set for outages on high voltage distribution feeders (11kV and 22kV). The process used to set the standards was the same as that used in setting the outage count standards. The annual cumulative outage duration standard for all customers within a given classification was established by finding the

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[20] Where progressive restoration occurs, ie the fault is isolated on a feeder section and supply to the remainder of the feeder is restored before the affected section, this method of data recording will ascribe the outage duration for the last transformer to be re-energised to all affected transformers, and hence considerably overstate the actual customer experience of outage duration.

average of this measure over the last five years (individual financial years 2001-02 to 2005-06) and rounding to the nearest half-integer. The minimum annual cumulative outage duration standard of any individual area within a classification was nominally set at twice the category average. This standard was then adjusted down, in the case of the Rural classifications, for two reasons: first, doubling the category average produced a minimum standard that was worse (from a customer viewpoint) than the existing TEC standard; and second, to provide a true target for Aurora, rather than a standard that could be met with little effort. For the High Density Commercial classification, it was recognised that the excessive outage durations had a significant impact upon the customers within this classification, which should be reflected within the standards.

Matters Raised in Submissions

In its submission, Aurora Energy noted the absence from the Draft Report of formal mathematical derivations of the two sets of targets:

> Aurora notes that there is no explicit methodology (mathematical notation) to explain the derivation of the two sets of proposed Performance Standards (number of outages and cumulative outage duration). Moreover, there is no explanation given as to how Aurora's performance against these standards is to be measured; that is, how the average number of outages and average cumulative durations for the classifications and areas are to be calculated, nor, indeed, is there an indication of what actually constitutes an outage. Provision of such detail would remove any ambiguity that may arise in calculating distribution network performance for comparison with the proposed standards. Aurora suggests that this clarification is undertaken by the working group and included in the final report.[21]

In regard to the lack of an explicit methodology in mathematical notation to explain the derivation of the two sets of standards, the working group considers that the additional complexity involved in including this material is not warranted, given that submissions supported the standards proposed and the methodology followed is outlined above.

The working group agrees with Aurora Energy's comments with respect to the inclusion of formal definitions of the reliability measures to be implemented, to remove the potential for ambiguity. Formal definitions of measures that the working group propose be used are included in Appendix D.

Momentary Average Interruption Frequency Index (MAIFI)

MAIFI is a measure of the number of very short interruptions to supply experienced per customer per year in a given region, and is defined in Appendix D. Momentary interruptions typically arise from the operation of reclosers, where sections of lines are briefly de-energised as a result of a fault, then automatically re-energised after a

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[21] Aurora Energy submission to the Joint Working Group *Distribution Network Performance Standards – Draft Report*, 1 December 2006.

set period of time. If the fault has rectified itself (such as might happen if a piece of bark had briefly shorted across a feeder and then blown off, or wires had clashed in high winds), supply will be restored. If the fault has not rectified itself, the recloser will again automatically open off the feeder section. If the recloser unsuccessfully attempts to restore supply more than a few times, it will open off the feeder section indefinitely, until a service crew repairs the fault.[22]

Momentary interruptions typically occur in radial networks (where there are no alternative sources of supply). As such, they are more common in rural areas. A few very short outages are generally seen as preferable to one prolonged outage, which would occur if a feeder tripped with no recloser installed.

The terms of reference require that the working group consider whether it is appropriate to include MAIFI in the reliability measures. The working group examined the capability of Aurora Energy's data systems to record MAIFI, and the historical information available on which to base a set of standards. Aurora Energy has advised that almost all reclosers now automatically log momentary interruptions, but that little reliable historical data exists.

The working group agreed that the Regulator should require Aurora Energy to commence reporting MAIFI data from the beginning of the new Pricing Determination, and that the Regulator would monitor MAIFI and determine whether reliability standards were required when standards are next reviewed. If such standards are required, a sufficient data set will have been collected through this process.

Minimum Individual Customer Reliability Indices (GSL Levels)

As noted above, the working group considered that the current operation of the GSL scheme is adequate, and that the stipulated triggers for payments, and levels of payments, are appropriate. As such, no additional analysis was conducted to redefine these measures.

The working group notes that the new standards would result in a 30 per cent increase in the number of customers classified as urban, in comparison to the existing reliability standards. Consequently, the working group examined the approximate cost that would be incurred by Aurora Energy in applying the current GSL standards to the reclassified customer base. The results of this analysis are contained in section 5.

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[22] For more information, refer to Aurora Energy's pamphlet *Momentary Power Interruptions*, November 2003.

APPENDIX C – DEFINED REGIONS

Critical Infrastructure

Area Name	Average (5 year) Annual Consumption (GWh)	Number of Installations
Hobart Critical	266.5	2 200

High Density Commercial

Area Name	Average (5 year) Annual Consumption (GWh)	Number of Installations
Burnie CBD	33.11	540
Devonport CBD	26.8	500
Glenorchy Commercial	27.86	270
Hobart CBD	93.55	3 420
Kings Meadows	8.13	140
Kingston Commercial	3.77	130
Launceston CBD	86.92	1 380
Rosny Commercial	34.61	520
TOTAL	**314.75**	**6 900**

Urban and Regional Centres

Area Name	Average (5 year) Annual Consumption (GWh)	Number of Installations
Bridport	7.56	880
Brighton	7.77	600
Burnie - Penguin	218.18	8 160
Deloraine	17.73	1 230
Devonport	282.43	11 610
Georgetown	18.35	1 650
Hadspen	7.64	740
Hobart Urban	1 434.08	103 550
Huonville	13.77	590

Area Name	Average (5 year) Annual Consumption (GWh)	Number of Installations
Kingston - Blackmans Bay	94.84	8 060
Latrobe	17.23	1 130
Launceston Urban	657.93	38 990
Lewisham - Dodges Ferry	11.36	1 520
Longford	14.86	1 330
Margate - Snug	13.82	1 120
Midway Point	9.56	920
New Norfolk	33.84	2 030
Perth	10.17	1 000
Port Sorell	19.24	2 100
Queenstown	16.73	1 120
Rosebery	6.03	590
Scottsdale Urban	11.78	940
Sheffield	6.79	490
Smithton	52.83	1 830
Somerset - Wynyard	70.87	3 710
Sorell	13.85	850
St Helens	10.73	790
Strahan	6.48	460
Tamar South	34.9	2 590
Turners Beach	10.4	890
Ulverstone	62.86	4 840
Westbury	18.09	600
TOTAL	**3 212.7**	**188 800**

Higher Density Rural

Area Name	Average (5 year) Annual Consumption (GWh)	Number of Installations
Beaconsfield - Beauty Point	63.13	1 220
Bicheno	4.53	480
Brighton Rural	8.29	740
Cambridge - Richmond	8.81	730

Area Name	Average (5 year) Annual Consumption (GWh)	Number of Installations
Campbell Town	5.34	480
Coles Bay	3.42	420
Copping - Dunalley	4.62	510
Cradle Coast	135.25	7 650
Derby - Ringarooma	8.29	440
Devon Hills-Evandale	13.06	1 010
Dilston - Windemere	3.1	240
Forcett - Dodges Ferry	2.37	260
Forestier Peninsula	2.88	420
Geeveston - Franklin	10.46	960
Granton-Magra	7.05	640
Huon-Channel	43.77	3 300
Huonville - Cygnet	4.53	400
Longford Higher Density Rural	32.53	2 290
Meander Valley Higher Density Rural	16.31	940
Oatlands	3.04	320
Penna	2.79	240
Pirates Bay - Nubeena - Port Arthur	6.97	1 250
Primrose Sands	2.6	720
Scottsdale Rural	9.97	580
Sidmouth - Deviot	5.29	570
Smithton Rural	57.53	2 470
South Arm	16.46	1 820
St Marys	1.49	170
Swansea	4.42	280
Triabunna - Orford	8.47	1 260
Wayatina	2.51	40
Winnaleah	1.8	120
Zeehan	4.7	450
TOTAL	**505.78**	**30 600**

Lower Density Rural

Area Name	Average (5 year) Annual Consumption (GWh)	Number of Installations
Bothwell Rural	1.52	220
Bruny Island	4.01	900
Burnie Rural	31.34	1 570
Channel Rural	16.74	2 150
Coal Valley Rural	7.75	880
Cressy - Blessington Rural	21.87	1 690
Derwent Valley Rural	24.54	2 500
Dover Rural	5.61	720
Far North East Rural	6.92	640
Fingal Valley Rural	11.78	680
George Town Industrial	0.06	10
Highlands	0.93	390
Huon Rural	10.98	1 330
Kempton Rural	6.96	880
North Coast	10.9	920
North East Rural	21.53	2 240
North West	24.05	1 760
Oatlands - Buckland Rural	7.53	1 120
Railton Rural	39.61	3 840
Ross Rural	4.55	510
Sorell - Dunalley	5.12	550
St Helens Rural	11.16	1 890
Tamar East Rural	16.85	1 800
Tamar West	19.06	2 290
Tasman Peninsula Rural	3.84	670
Triabunna - St Marys Rural	4.94	850
West Coast	2.43	320
TOTAL	**334.36**	**31 100**

APPENDIX D – DEFINITIONS AND MEASURES OF RELIABILITY

There are four commonly used measures of reliability for an electricity network, which are referred to in this report:

Term	Meaning		Definition
SAIFI	System Average Interruption Frequency Index	=	$\frac{\text{Total number of customer interruptions}}{\text{Total number of customers}}$
SAIDI	System Average Interruption Duration Index	=	$\frac{\text{The sum of customer interruption durations}}{\text{Total number of customers}}$
CAIDI	Customer Average Interruption Duration Index	=	$\frac{\text{The sum of customer interruption durations}}{\text{Total number of customer interruptions}}$
MAIFI	Momentary Average Interruption Frequency Index	=	$\frac{\text{Total \# of customer momentary interruptions}}{\text{Total number of customers}}$

In reality, SAIFI and SAIDI, the measures of frequency and duration of interruptions per customer, are commonly replaced by analogous indices based on installed capacity, not customers, as follows:

Term	Meaning		Definition
ASIFI	Average System Interruption Frequency Index	=	$\frac{\text{Total connected kVA interrupted}}{\text{Total connected kVA}}$
ASIDI	Average System Interruption Duration Index	=	$\frac{\Sigma\ \text{Connected kVA duration interrupted}}{\text{Total connected kVA}}$

Aurora Energy currently records and reports ASIFI and ASIDI, rather than SAIFI and SAIDI.

Method of Calculation of Classification and Area Annual Performance for Comparison with the Standards

Target	Column		Definition
Classification Number of Interruptions	(Column A)	=	$\dfrac{\Sigma\ \Phi_{(j,C)}}{n_C}$
Individual Area Outage Number	(Column B)	=	$\dfrac{\Sigma\ \Phi_{(j,R)}}{n_R}$
Classification Number of Interruptions	(Column C)	=	$\dfrac{\Sigma\ \Delta_{(j,C)}}{n_C}$
Individual Area Outage Duration	(Column D)	=	$\dfrac{\Sigma\ \Delta_{(j,R)}}{n_R}$

Where: $\Phi_{(j,C)}$ is the number of interruptions for transformer *j* in category *C* in a year;
$\Phi_{(j,R)}$ is the number of interruptions for transformer *j* in region *R* in a year;
n_c is the number of transformers in category *C*;
n_R is the number of transformers in region *R*;
$\Delta_{(j,C)}$ is the duration of outages for transformer *j* in category *C* in a year;
$\Delta_{(j,R)}$ is the duration of outages for transformer *j* in region *R* in a year.

Column refers to the relevant target as outlined in Table 4.1 and Table 4.2.

Φ and Δ exclude outages resulting from generation, transmission and third party causes.

APPENDIX E – CAPITAL COSTS

The following table shows the indicative estimated cost per community to meet the proposed standards, for those areas where current reliability would be non-compliant. The table shows the capital cost required, the capital cost converted to an annuity and expressed per unit consumption of customers within the area, and the impact that the annualised cost would have on distribution tariffs if spread across all customers.

While distribution tariffs generally include a standing charge and a variable (per unit consumption) component, in this instance an averaged distribution tariff of 3.2 c/kWh has been calculated and used, averaging both the fixed and variable charges, and the various rates for differing customer classes. Capital costs have been annualised assuming a 35-year asset life and an interest rate of 7 per cent.

The value of 3.2 c/kWh gives a meaningful context for the annualised cost per unit consumption of installations within an area, representing the cost that customers receiving the benefit would bear if only those customers, and not the entire customer base, paid for the capital work.

In comparison, the final column demonstrates the impact of the cost of the reliability projects on all customers' distribution tariffs; that is, the annualised project cost as a proportion of current tariffs. This figure represents the impact if the cost is spread over the entire customer base. This figure does not represent a percentage tariff increase, as Aurora Energy currently allocates expenditure to reliability projects, and these works will be carried out in line with that practice, but rather gives an indication of the relative impact on all customers of individual projects.

All figures in the following table are indicative only; detailed project costs will be developed and submitted to the Regulator as part of Aurora Energy's submission for the Price Determination for distribution services.

Classification	Area name	Additional capital to meet standards ($)	Annualised cost per area annual consumption (c/kWh)	Proportion of all customers' distribution tariffs (%)
High Density Commercial	Devonport CBD	350 000	0.10	0.02
	Kings Meadows	300 000	0.28	0.02
	Total HDC	**650 000**	**0.14**	**0.03**
Urban	Georgetown	100 000	0.04	0.01
	Longford	300 000	0.16	0.02
	Perth	450 000	0.34	0.02
	Sheffield	100 000	0.11	0.01
	Somerset - Wynyard	800 000	0.09	0.04

Classification	Area name	Additional capital to meet standards ($)	Annualised cost per area annual consumption (c/kWh)	Proportion of all customers' distribution tariffs (%)
	St Helens	350 000	0.25	0.02
	Strahan	750 000	0.89	0.04
	Tamar South	850 000	0.19	0.04
	Turners Beach	950 000	0.70	0.05
	Ulverstone	750 000	0.09	0.04
	Westbury	400 000	0.17	0.02
	Total Urban	**5 800 000**	**0.17**	**0.30**
Higher Density Rural	Derby - Ringarooma	100 000	0.09	0.01
	Dilston - Windemere	210 000	0.52	0.01
	Forestier Peninsula	550 000	1.47	0.03
	Longford Higher Density Rural	400 000	0.09	0.02
	Oatlands	400 000	1.01	0.02
	Pirates Bay - Nubeena - Port Arthur	1 100 000	1.21	0.06
	Sidmouth - Deviot	500 000	0.73	0.03
	Swansea	400 000	0.70	0.02
	Total Higher Density Rural	**3 660 000**	**0.42**	**0.19**
Lower Density Rural	Bruny Island	3 000	0.01	0.00
	North Coast	1 500 000	1.06	0.08
	North East Rural	900 000	0.32	0.05
	North West	750 000	0.24	0.04
	Total Lower Density Rural	**3 153 000**	0.40	**0.16**
TOTAL		**13 263 000**	0.24	**0.69**

APPENDIX F – SUBMISSIONS

Table F.1 lists submissions that were received in response to the Draft Report.

Table F.1 Submissions received in response to the Draft Report

Interested party	Date received
Hobart City Council	14 November 2006
Mr Tim McManus	14 November 2006
Mr Dennis Crawford	21 November 2006
Department of Economic Development	21 November 2006
Essential Services Commission, Victoria	27 November 2006
Aurora Energy Pty Ltd	1 December 2006
EnergyAustralia Pty Ltd	15 January 2007

All submissions may be downloaded in full from the Regulator's website at www.energyregulator.tas.gov.au.

APPENDIX G – HISTORICAL RELIABILITY

The following charts present the historical average number and duration of interruptions for each region each year for the last six years.

Figure G.1. High Density Commercial number of interruptions

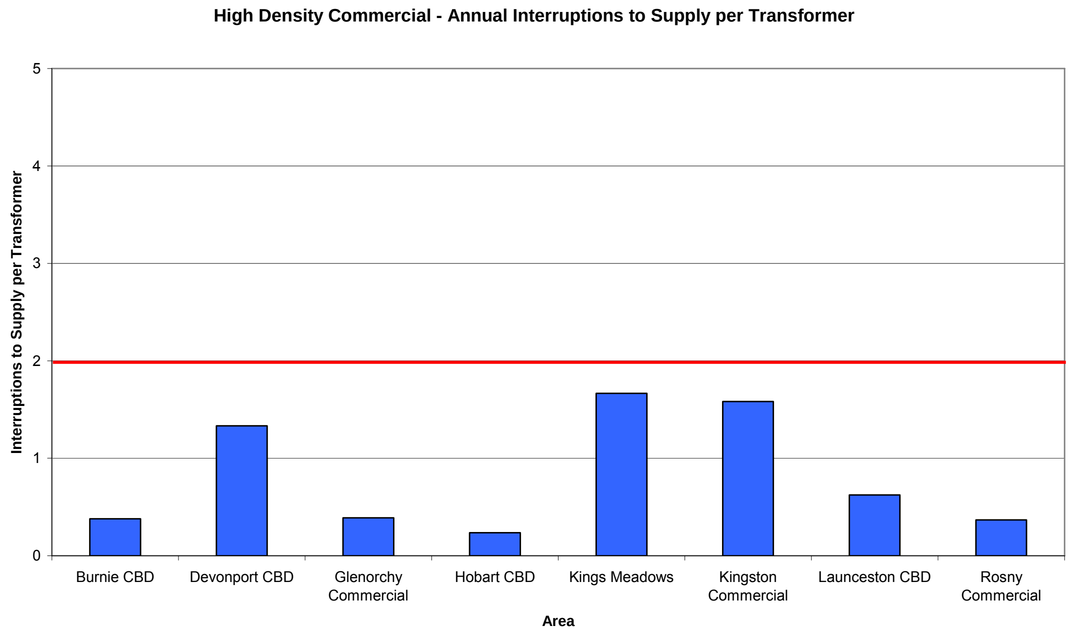

Figure G.2. High Density Commercial duration of interruptions

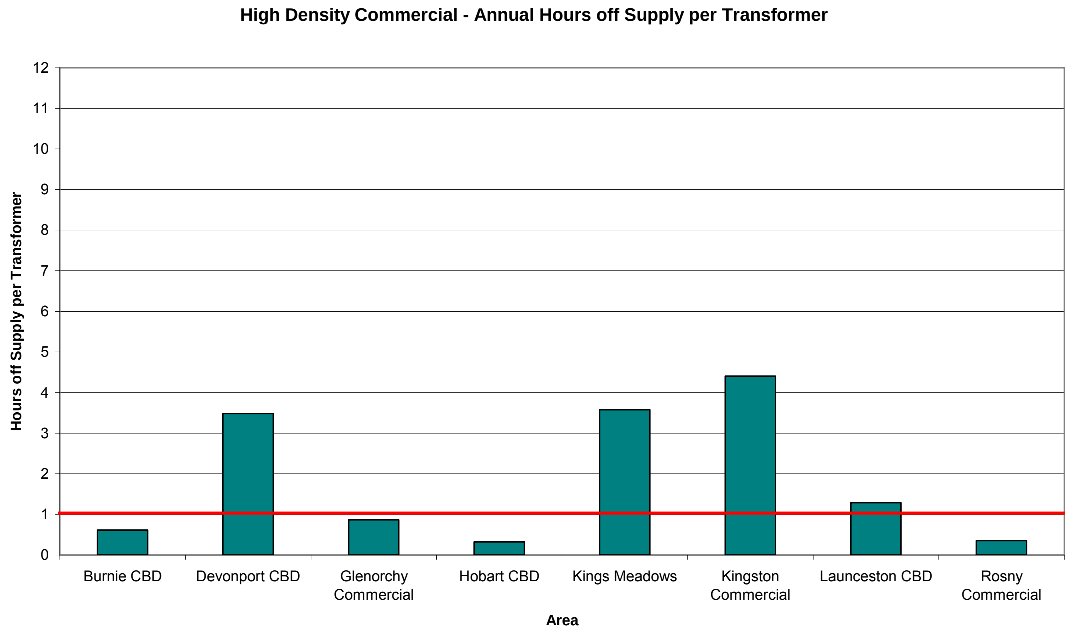

Figure G.3. Urban number of interruptions

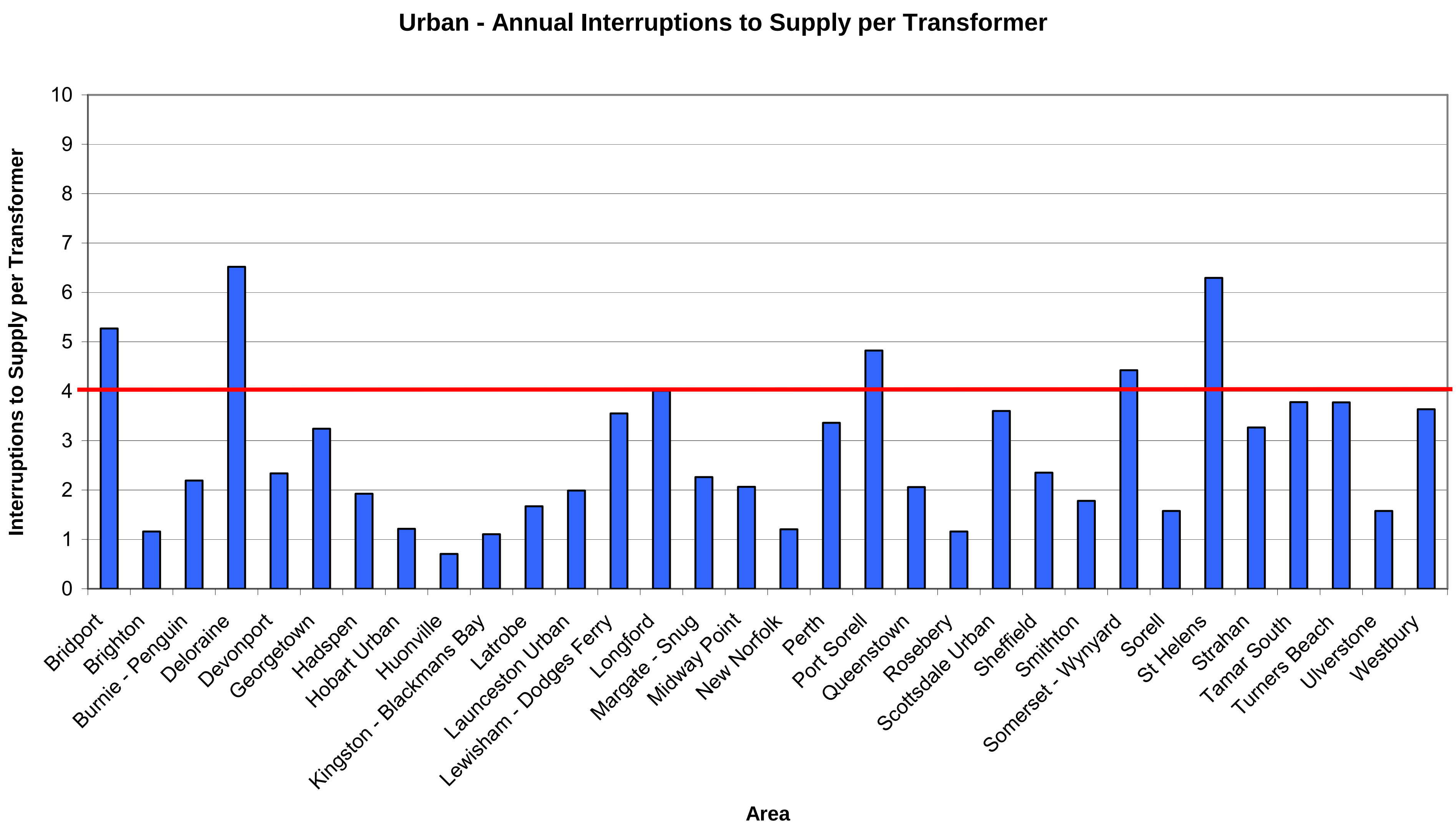

Figure G.4. Urban duration of interruptions

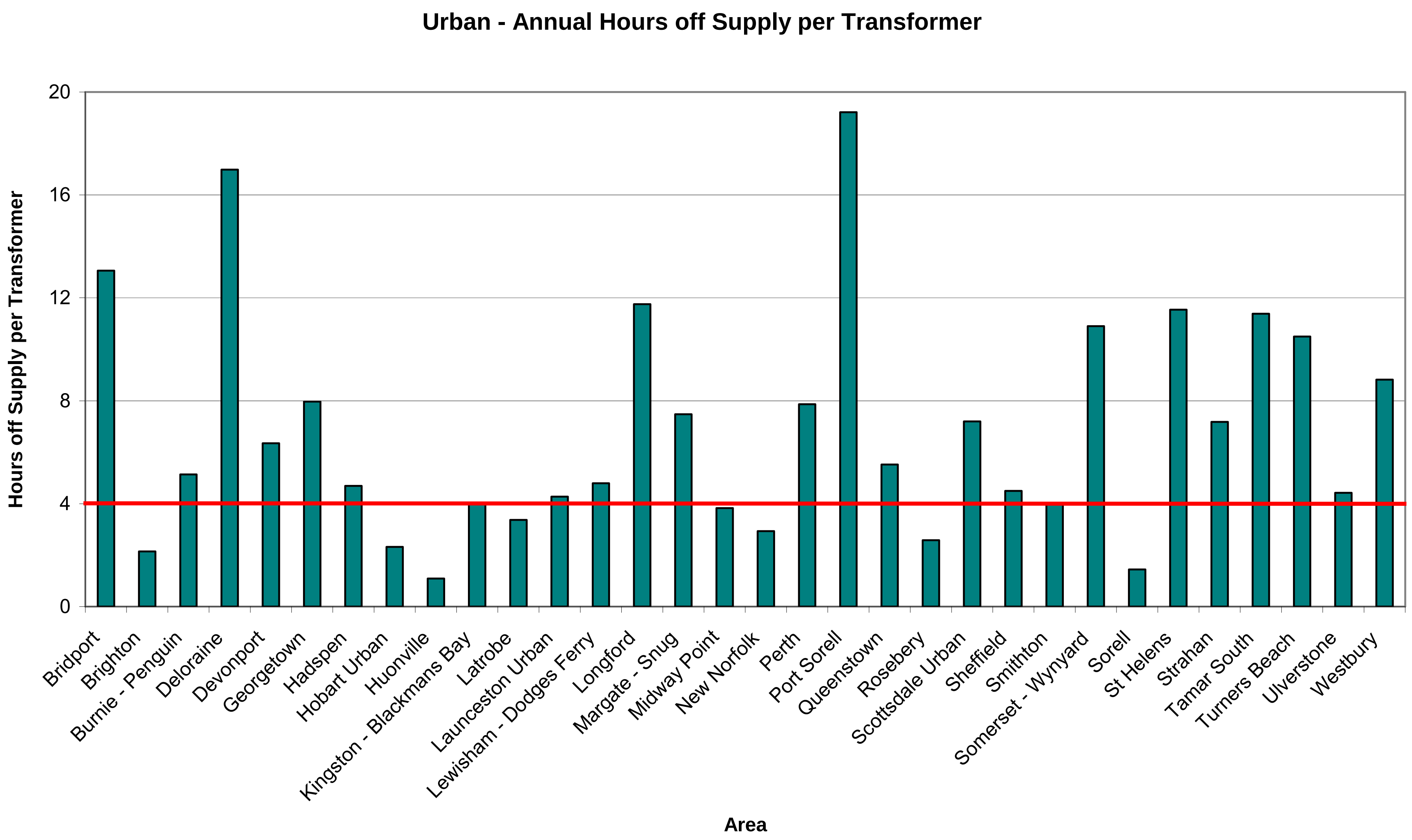

Figure G.5. Higher Density Rural number of interruptions

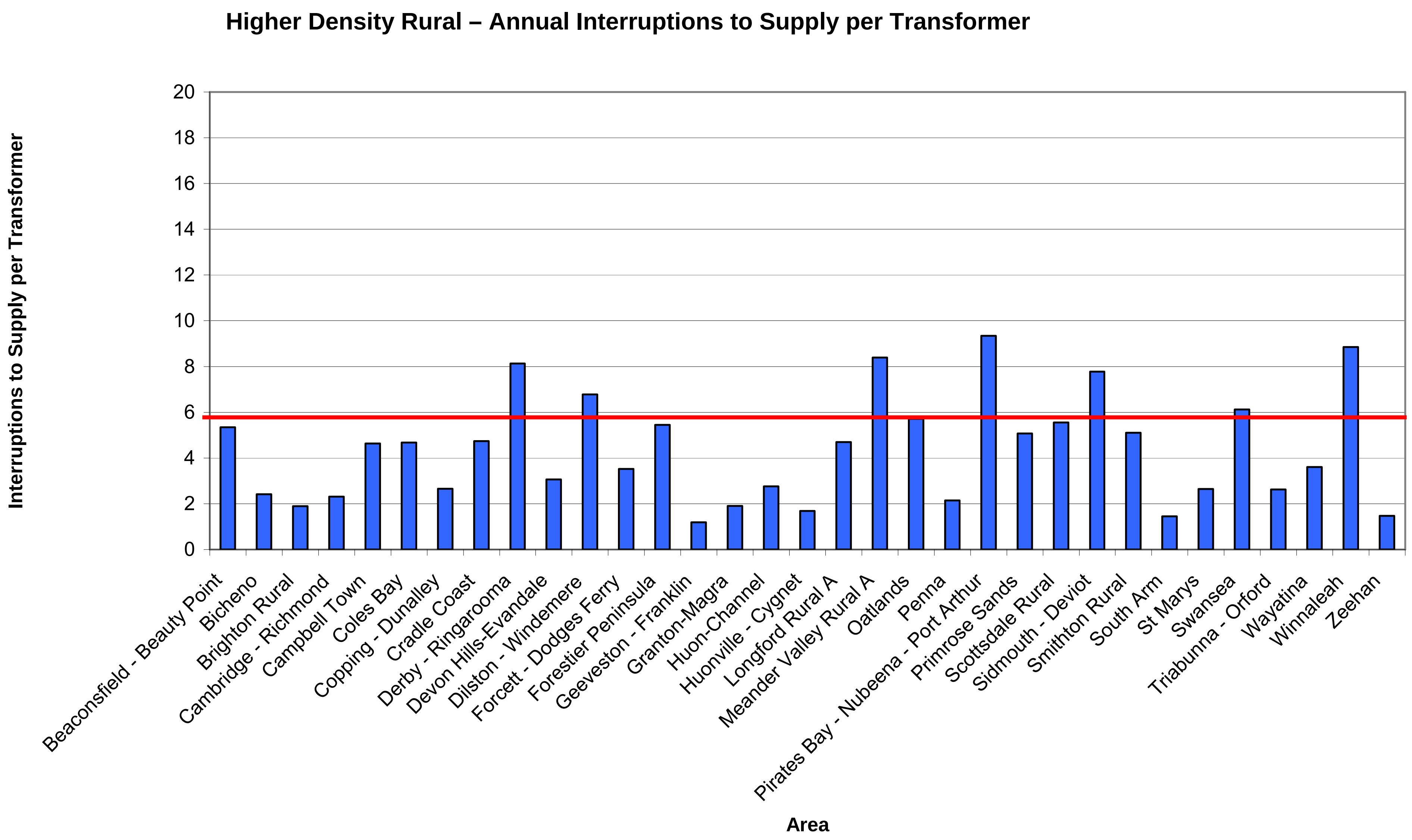

Figure G.6. Higher Density Rural duration of interruptions

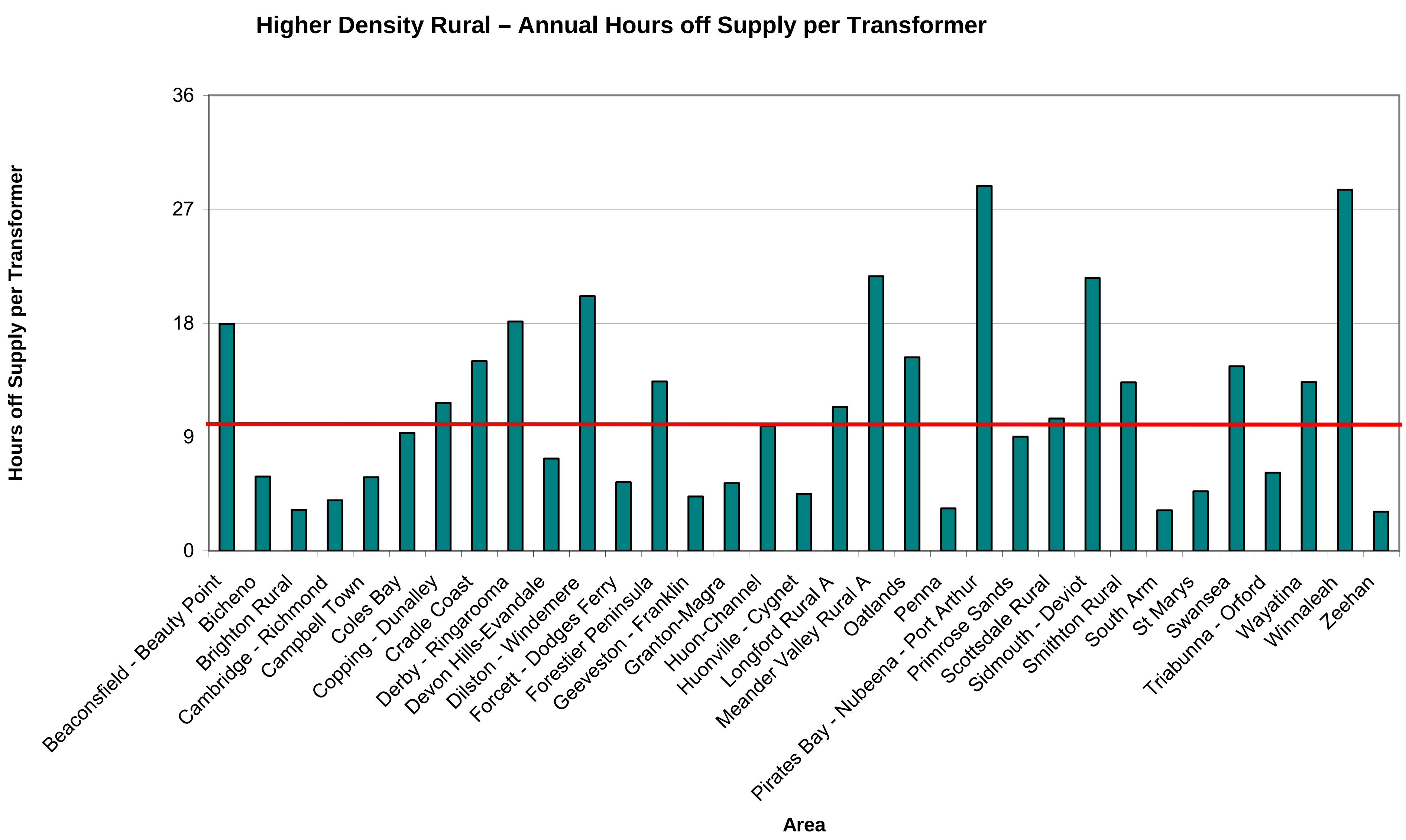

Figure G.7. Lower Density Rural number of interruptions

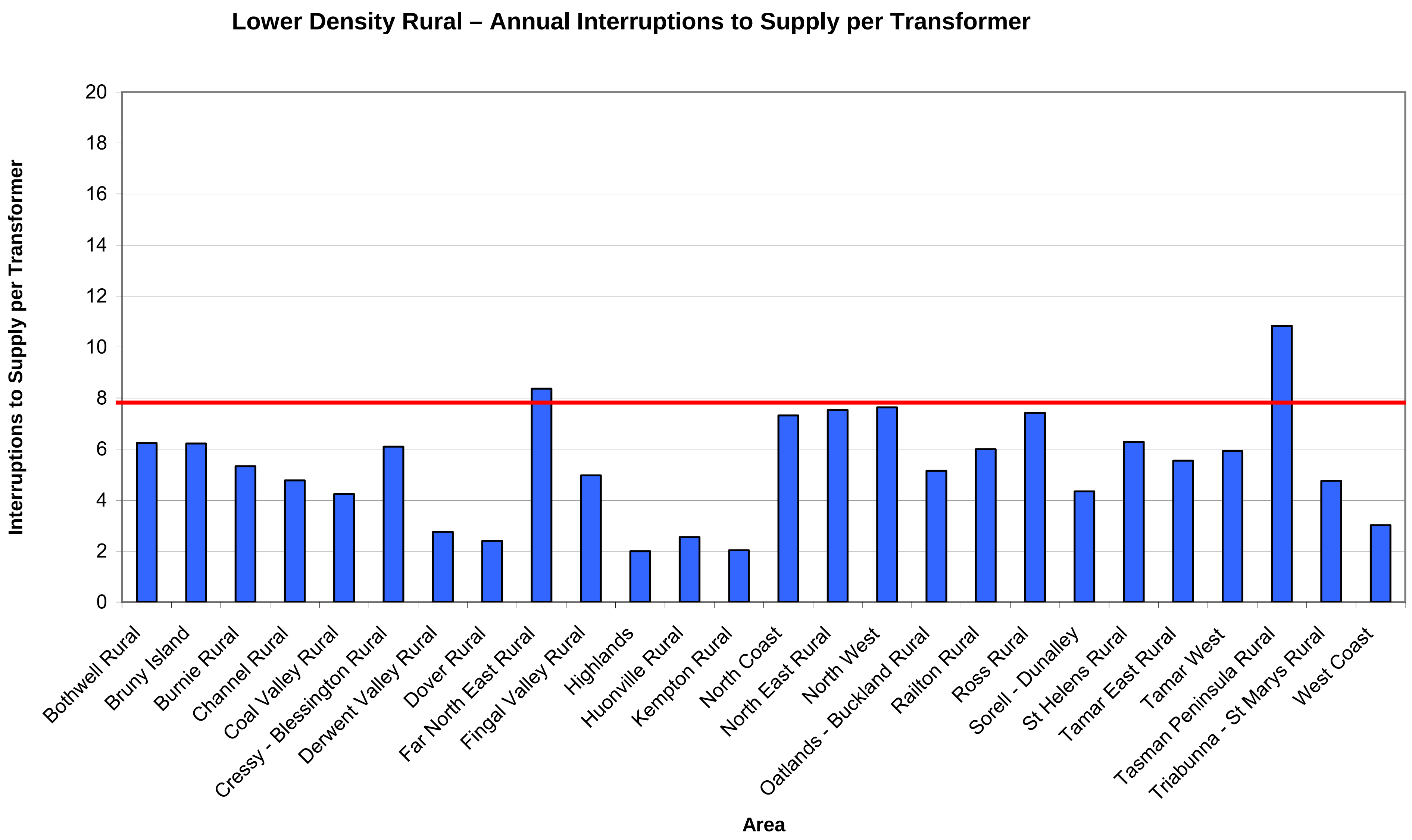

Figure G.8. Lower Density Rural duration of interruptions