Economic Benchmarking RIN

Audited Response

At 30 June 2013

As Submitted to the AER

CONTACT

This document is the responsibility of the Commercial, Regulatory and Strategy Group within the Distribution Business of Aurora Energy Pty Ltd (ABN 85 082 464 622). Please contact the indicated owner of the document with any queries or suggestions.

RESPONSIBILITIES

Document Owner

Network Regulatory Manager - Distribution Business
Aurora Energy Pty Ltd
21 Kirksway Place
Hobart TAS 7000
email: RRP2012@auroraenergy.com.au

Document Management

Commercial, Regulatory and Strategy Group

Contents

Abbreviations

AER	Australian Energy Regulator
Asset History	The Distribution Business asset history data warehouse (owned by the Asset Investment & Performance team) - generally contains historical asset information
Aurora	Aurora Energy Pty Ltd
CAM	Cost Allocation Method
DUoS	Distribution Use of System
ICAM	Indirect Cost Allocation Model
OTTER	Office of the Tasmanian Electricity Regulator
POW	Program of Work
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	Aurora Distribution Business custom asset reporting database (SAM reporting)
SDW	Spatial Data Warehouse - generally contains 'live' data
Transend	Transend Networks Pty Ltd
TUoS	Transmission Use of System
WASP	WASP (Works, Assets, Solutions and People) - program-of-work management system.

Confidentiality

Aurora has assessed the confidentiality of this Economic Benchmarking RIN Response in accordance with the AER's Confidentiality Guideline (November 2013).

Confidentiality Claims						
Document	**Description**	**Topic**	**Category**	**Explanation**	**Detriment from disclosure**	**Detriment v public benefit**
Title, page and paragraph number of document containing confidential information	*Description of the confidential information*	*Topic the confidential information relates to (e.g. capex, opex, WACC)*	*Confidentiality category*	*Explanation of categorisation*	*Detriment to Aurora associated with disclosure of the identified information*	*Information supporting why the identified detriment outweighs the public benefit of publication*
Economic Benchmarking RIN Audited Response at 30 June 2013 Page 6. First paragraph.	Home address of Aurora Chief Executive Officer.	Statutory Declaration. True and accurate certification for RIN response (in accordance with RIN Appendix C).	Personal information.	Release of Aurora Chief Executive Officer's home address raises material privacy issues.	Breach of the personal privacy of the Aurora Chief Executive Officer.	There is no public benefit from the publication of the home address of the Aurora Chief Executive Officer. Home address provided to ensure a compliant Statutory Declaration in accordance with the *Oaths Act 2001*.

Proportion of confidential material					
Submission title	**Pages with confidential content**	**Pages with no confidential content**	**Total pages**	**Percentage of pages with confidential content**	**Percentage of pages with no confidential content**
Economic Benchmarking RIN Audited Response at 30 June 2013	1	80	81	1%	99%

Statutory Declaration

OATHS ACT 2001

STATUTORY DECLARATION

I (full name) ....Peter Leigh Davis....

of (residential address)...[redacted]

Occupation ....Chief Executive Officer....

do solemnly and sincerely declare that:

1. I am an officer, for the purposes of the *National Electricity (Tasmania) Law* (**NEL**), of Aurora Energy Pty Ltd (ACN 082 464 622), a regulated network service provider for the purposes of section 28D of the NEL. I am authorised by Aurora Energy Pty Ltd to make this statutory declaration as part of the response of Aurora Energy Pty Ltd (**Aurora Energy**) to the Regulatory Information Notice dated 28 November 2013 (**Notice**) served on Aurora Energy by the Australian Energy Regulator (**AER**).

2. Having had regard to the Notice, I say that the actual information provided in Aurora Energy's response to the Notice is, to the best of my information, knowledge and belief:

   (a) in accordance with the requirements of the Notice; and

   (b) true and accurate.

3. Where it is not possible to provide actual information to comply with the Notice, Aurora Energy has, to the best of my information, knowledge and belief, for the purposes of complying with the Notice:

   (a) provided Aurora Energy's best estimate of the information in accordance with the requirements of the Notice; and

   (b) provided the basis for each estimate, including assumptions made and reasons why the estimate is the best estimate, given the information sought in the Notice.

I make this solemn declaration under the *Oaths Act 2001*.

Declared at ....Hobart....
(place)

on ....28 April 2014....
(date)

....
(Signature)

Before me....Solicitor admitted to practice in TAS, NSW, VIC
(Justice, commissioner for declarations or authorised person)

Janelle Maree O'Reilly
Level 2, 21 Kirksway Place, Hobart 7000.

Audit Report

Ernst & Young
8 Exhibition Street
Melbourne VIC 3000 Australia
GPO Box 67 Melbourne VIC 3001

Tel: +61 3 9288 8000
Fax: +61 3 8650 7777
ey.com/au

Independent Auditor's Report to the Directors of Aurora Energy Pty Ltd

We have audited the information within tables 2.1, 2.2, 2.3, 3.1, 3.2, 3.3, 4.1, 4.2 and 4.3 in the data template entitled *'Aurora Energy EB RIN 2013 Actual Information.xlsx'* ("Actual Financial Information") attached at Appendix A, which has been prepared in accordance with Aurora Energy Pty Ltd ("Aurora Energy")'s Basis of Preparation (the "Basis of Preparation") in response to the Economic Benchmarking Regulatory Information Notice ("the Notice") issued by the Australian Energy Regulator ("AER"), for the regulatory years 2008/09 to 2012/13 inclusive. In accordance with the requirements of the Notice, information presented in the Actual Financial Information before this date range has not been subject to audit.

The Australian Energy Regulator requires the Actual Financial Information and the accompanying Basis of Preparation for the performance of a function conferred on it under the National Electricity Law, namely conducting various benchmarking exercises as outlined in the Regulatory Information Notice issued to Aurora Energy on 28 November 2013.

Management's Responsibility for the Data Template and Basis of Preparation

Management is responsible for the preparation and fair presentation of the Actual Financial Information in accordance with the requirements of the Notice and Aurora Energy's Basis of Preparation, and for such internal controls as management determines are necessary to enable the preparation of the Actual Financial Information that is free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on the Actual Financial Information based on our audit. We conducted our audit in accordance with ASA 805 *Special Considerations – Audits of Single Financial Statements and Specific Elements, Accounts or Items of a Financial Statement* ("ASA 805"). ASA 805 requires that we comply with relevant ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Actual Financial Information is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Actual Financial Information. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the Actual Financial Information, whether due to fraud or error. In making those risk assessments, the auditor considers internal controls relevant to the entity's preparation of the Actual Financial Information in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal controls.

Independence

In conducting our procedures we have complied with the independence requirements of the Australian professional accounting bodies.

Opinion

In our opinion, the Actual Financial Information is presented fairly, in all material respects, in accordance with the requirements of the Notice and Aurora Energy's Basis of Preparation.

Restriction on Distribution

Without modifying our opinion, we draw attention to the fact that the Actual Financial Information is prepared to assist Aurora Energy to meet the requirements of the Notice. As a result, the Actual Financial Information may not be suitable for another purpose. Our report is intended solely for Aurora Energy and the AER and should not be distributed to any other parties.

Ernst & Young

Ernst & Young

Melbourne
30 April 2014

Ernst & Young
8 Exhibition Street
Melbourne VIC 3000 Australia
GPO Box 67 Melbourne VIC 3001

Tel: +61 3 9288 8000
Fax: +61 3 8650 7777
ey.com/au

Independent Assurance Practitioner's Report to the Directors of Aurora Energy Pty Ltd

We have reviewed the following information:

- The information within tables 2.1, 2.2, 3.4, and 4.2 in the data template entitled *'Aurora Energy EB RIN 2013 Estimated Information.xlsx'* ("Estimated Financial Information") attached at Appendix B; and

- The information within tables 4.4, 5.1, 5.2, 5.3, 6.1, 6.2, 6.3, 7.1, 7.2, 7.3, 7.4, 8.1, 8.2, 8.3 and 8.4 in the data templates entitled *'Aurora Energy EB RIN 2013 Actual Information.xlsx'* and *'Aurora Energy EB RIN 2013 Estimated Information.xlsx'* ("Non-Financial Information") attached at Appendices A and B respectively.

This information has been prepared in accordance with Aurora Energy Pty Ltd ("Aurora Energy")'s Basis of Preparation (the "Basis of Preparation") in response to the Economic Benchmarking Regulatory Information Notice ("the Notice") issued by the Australian Energy Regulator ("AER"), for the regulatory years 2008/09 to 2012/13 inclusive. In accordance with the requirements of the Notice, information presented in the Estimated Financial Information and Non-Financial Information before this date range has not been subject to review.

The Australian Energy Regulator requires the Estimated Financial Information, Non-Financial Information and an accompanying Basis of Preparation document for the performance of a function conferred on it under the National Electricity Law, namely conducting various benchmarking exercises as outlined in the Regulatory Information Notice issued to Aurora Energy on 28 November 2013.

Management's Responsibility for the Data Template and Basis of Preparation

Management is responsible for the preparation of the Estimated Financial Information, Non-Financial Information and Basis of Preparation, and has noted in the Basis of Preparation whether it considers that the information supplied is appropriate for the benchmarking activities of the Australian Energy Regulator. Management is also responsible for such internal controls as management determines are necessary to enable the preparation of the Estimated Financial Information and Non-Financial Information that are free from material misstatement, whether due to fraud or error.

Assurance Practitioner's Responsibility

Our responsibility is to express a conclusion on the Estimated Financial Information and Non-Financial Information based on our review.

We have conducted our review of the Estimated Financial Information in accordance with the Australian Standard on Review Engagements ASRE 2405 *Review of Historical Financial Information Other than a Financial Report* in order to state whether, on the basis of the procedures described, anything has come to our attention that causes us to believe that the Estimated Financial Information is not prepared, in all material respects, in accordance with the Basis of Preparation and the requirements of the Notice.

We have conducted our review of the Non-Financial Information in accordance with the Australian Standard on Assurance Engagements ASAE 3000 *Assurance Engagements Other than Audits or Reviews of Historical Financial Information* in order to state whether, on the basis of the procedures described, anything has come to our attention that causes us to believe that the Non-Financial Information is not prepared, in all material respects, in accordance with the Basis of Preparation and the requirements of the Notice.

ASRE 2405 and ASAE 3000 require us to comply with the requirements of the applicable code of professional conduct of a professional accounting body.

A review consists of making enquiries, primarily of persons responsible for the information, and applying analytical and other review procedures. Specifically, we have agreed the Estimated Financial Information and the Non-Financial Information to data extracted by company personnel from relevant company operating systems. Our procedures involved undertaking a walkthrough of the systems / process by which data is captured and reported. Due to the nature of the systems / processes used, we have undertaken a substantive approach to our procedures.

A review is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

Independence

In conducting our procedures we have complied with the independence requirements of the Australian professional accounting bodies.

Conclusion

Based on our review, which is not an audit, nothing has come to our attention that causes us to believe that the Estimated Financial Information and Non-Financial Information is not prepared, in all material respects, in accordance with the requirements of the Notice or Aurora Energy's Basis of Preparation.

Restriction on Distribution

Without modifying our conclusion, we draw attention to the fact that the Non-Financial Information is prepared to assist Aurora Energy to meet the requirements of the Notice. As a result, the Non-Financial Information may not be suitable for another purpose. Our report is intended solely for Aurora Energy and the AER and should not be distributed to any other parties.

Ernst & Young

Ernst & Young
Melbourne
30 April 2014

Basis of Preparation

Template 2 - Revenue

Table 2.1 – Revenue grouping by chargeable quantity

1	Demonstrate how the information provided is consistent with the requirements of the RIN

DREV0101 - Revenue from fixed customer charges

- Standard Control Services – fixed customer charges tariff components only.
- Alternative Control Services – not applicable to Aurora.

DREV0102 - Revenue from energy delivery charges where time use is not a determinant

- Revenue derived from network tariffs comprised of energy charging parameters, where charges do not vary based on time of use.

DREV0103 - Revenue from on–peak energy delivery charges
DREV0104 - Revenue from shoulder period energy delivery charges
DREV0105 - Revenue from off–peak energy delivery charges

- Data has been extracted from the billing system based on time of use provisions.

DREV0106 - Revenue from controlled load customer charges

- Standard control services – revenue derived from load control tariff components only
- Alternative control services – not applicable to Aurora.

DREV0107 - Revenue from unmetered supplies

- Standard control services – revenue derived from unmetered supply points (including street lighting).
- Alternative control services – not applicable to Aurora.

DREV0108 - Revenue from contracted maximum demand charges

- Standard control services - revenue received as a result of additional or excess demand charges (tariff components).
- Alternative control services – not applicable to Aurora.

DREV0109 - Revenue from measured maximum demand charges

- Standard control services - revenue derived from demand tariff components. This includes specified and actual demand, excluding revenue derived from demand overrun charges or additional demand based charges (included as part of DREV0108).
- Alternative control services – not applicable to Aurora.

DREV0110 - Revenue from metering charges

- Standard control services - not applicable, the provision of metering services has been classified as an alternative control service.
- Alternative control services – revenue received from metering daily charge tariff components (excludes revenue received as a result of MDP charges, this revenue has been included as part of DREV0113).

DREV0111 – Revenue from connections charges

- Aurora does not derive revenue via a connection based charge.

DREV0112 - Revenue from public lighting charges

- Standard control services – not applicable to Aurora.
- Alternative control services – revenue received from the provision of public lighting services (including contract lighting services). Excludes revenue received for the use of the shared network (network tariff N20 – street lighting).

DREV0113 - Revenue from other sources

- Standard control services - revenue received from Aurora's PAYG tariff and accrual associated with the movement unbilled energy included as the revenue reported within the Aurora's Regulatory Accounts.
- Alternative control services – revenue received from the provision of fee based services and quoted services.

2	Explain the source of the information to support the variable

- The data for variables DREV00101 - DREV0110 and DREV0112 is sourced from Aurora's market and billing systems.
- The data for DREV0113 - Revenue from other sources is sourced from Aurora's market and billing systems and the revenue associated with the movement in unbilled energy (sourced from Aurora's Regulatory Accounts).
- For 2009, the metering revenue (DREV0110) has been sourced from the Regulated Accounts.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

DREV0101 - Revenue from fixed customer charges

Revenue derived from network tariff fixed daily charge components, includes the following network tariffs:

- N01 – General Network – Residential
- N02 – General Network – Business
- N02a – General Network – Business, Nursing Homes
- N02b – General Network – Business, Curtilage
- N03 – LV kW Demand
- N05 – Uncontrolled Energy
- N06 – Controlled Energy
- N06a - LV Controlled Energy
- N07 - Small LV Unmetered
- N08 – LV Day/Night Irrigation
- N08a – LV Irrigation – TOU
- N09 – LV kVA Demand
- N10s – HV kVA Specified Demand
- N11 – HV kW Demand
- N13 – LV PAYG
- N13b – LV TOU – Business
- N13r – LV TOU – Residential

- Unbilled use of system charges has been apportioned on a percentage basis between the tariff charging parameters.
- Alternative Control Revenue – included under the various classifications.

DREV0102 - Revenue from energy delivery charges where time use is not a determinant

Revenue derived from network tariffs comprised of energy charging parameters where charges do not vary based on time of use. Derived based on the following network tariffs:

- N01 – General Network – Residential
- N02 – General Network – Business
- N02a – General Network – Business, Nursing Homes
- N02b – General Network – Business, Curtilage
- N03 – LV kW Demand
- N05 – Uncontrolled Energy
- N06 – Controlled Energy
- N06a - LV Controlled Energy
- N07 - Small LV Unmetered
- N08 – LV Day/Night Irrigation
- N09 – LV kVA Demand
- N11 – HV kW Demand
- N10 – HV kVA Demand
- N13 – LV PAYG

DREV0103 - Revenue from on–peak energy delivery charges
DREV0104 - Revenue from shoulder period energy delivery charges
DREV0105 - Revenue from off–peak energy delivery charges

- A uniform time of use period assumption has been applied for the purposes of table completion. Various tariffs have difference time periods in respect to peak, shoulder and off-peak, however for consistency the time periods outlined in the table below have been applied consistently across tariffs and years.

Time Period	Tariff Rate
Week Day (07:00 – 22:00) (Monday – Friday)	Peak
Weekend Day (07:00 – 22:00) (Saturday and Sunday)	Shoulder
Any Day (22:00 – 24:00) (Monday – Sunday)	Off-peak
Any Day (0:00 – 07:00) (Monday – Sunday)	Off-peak

DREV0106 - Revenue from controlled load customer charges

Revenue derived from network controlled energy tariffs, variable tariff components only (revenue derived from fixed tariff components included in DREV101).

Aurora's controlled energy tariffs include:

- N06 – Controlled Energy
- N06a - LV Controlled Energy

DREV0107 - Revenue from unmetered supplies

Aurora has two network tariffs which related to unmetered supply. Revenue derived from these two network tariffs (variable tariff components only), have been reported in this table. These two tariffs are:

- N07 – Small LV Unmetered; and
- N20 – Street Lighting;

DREV0108 - Revenue from contracted maximum demand charges

Revenue received as a result of excess or additional demand network charges (tariff components). Aurora's demand based tariffs include a charging parameter for excess or additional demand, demand over and above a specified or contract level is charged at a different rate. Aurora's demand based tariffs include the following:

- N03 – LV kW Demand
- N09 – LV kVA Demand
- N10 – HV kVA Demand
- N10s – HV kVA Specified Demand
- N15 – HV kVA Specified Demand (>2.0 MVA)
- ITC's – Individual Network Tariff Calculations

DREV0109 - Revenue from measured maximum demand charges

Revenue derived from network demand based tariffs (excludes revenue received as a result of excess or overrun demand charges). Aurora's demand tariffs include:

- N03 – LV kW Demand
- N09 – LV kVA Demand

- N10 – HV kVA Demand
- N10s – HV kVA Specified Demand
- N11 – HV kW Demand
- N15 – HV kVA Specified Demand (>2.0 MVA)
- ITC's – Individual Network Tariff Calculations

DREV0110 - Revenue from metering charges

Revenue received from metering daily charge tariff components associated with the following network tariffs:

- N01 – General Network - Residential
- N10 – HV kVA Demand
- N03 – LV kW Demand
- N02b – General Network – Business, Curtilage
- N09 – LV kVA Demand
- N02 – General Network - Business
- N02a – General Network – Business, Nursing Homes
- N13b (N13c) – LV ToU Business
- N06 – Controlled Energy
- N06a – Controlled Energy
- N05 – Uncontrolled Energy
- N13r – LV ToU - Residential
- N08 – LV Day/Night (Irrigation)
- N08a (N08b) – LV Irrigation (ToU)
- N11 – HV kW Demand

DREV0111 – Revenue from connections charges

- Aurora does not have any revenue from connections charges.

DREV0112 – Revenue from public lighting charges

- Revenue derived from the provision of public lighting services and contract lighting services. Data has been sourced from Aurora's billing systems.

DREV0113 – Revenue from other sources

- Revenue derived from the provision of fee based services (special services) and quoted services as captured in Aurora's financial systems. Data manipulation not required.
- Movement in unbilled energy as reported in Aurora's Regulatory Accounts.

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)
Why was it not possible to use actual information?	
Table 2.1 – Revenue grouping by chargeable quantity • For 2006 and 2007 the required data is not available from Aurora's market and billing systems. • For 2008 and 2013 the metering revenue from the billing system contained data quality issues.	
The basis for the estimate	
Table 2.1 – Revenue grouping by chargeable quantity **Estimation approach** • Revenue as recorded in the Regulatory Accounts has been used to estimate the 2006 and 2007 variables. • The revenue recorded in the Regulatory Accounts has been apportioned across the revenue grouping in accordance with the actual percentage splits for 2008 to 2013 (using a normalised average). • For 2008, the Regulated Accounts value for metering revenue has been used, allocated across the RIN categories using the base billing data percentages. • For 2013, the metering revenue from the Regulated Accounts has been apportioned based on the base data used for month end reporting. **Estimation assumptions** • It is assumed that the application of the 2008 to 2013 normalised average is representative of the allocation of revenue across the revenue groupings for 2006 and 2007.	

Table 2.2 – Revenue grouping by customer type or class

1	Demonstrate how the information provided is consistent with the requirements of the RIN

DREV0201 - Revenue from residential customers

- Standard control services - revenue received from residential customers (residential network tariffs).
- Alternative control services - revenue derived from the provision of metering services for residential customers.

DREV0202 - Revenue from non-residential customers not on demand tariffs

- Standard control services - revenue received from non-residential customers on energy based tariffs or via energy based tariff components.
- Alternative control services – revenue derived from the provision of metering services for non-residential customers.

DREV0203 - Revenue from non-residential low voltage demand tariff customers

- Standard control services - revenue received from non-residential low voltage demand tariff customers.
- Alternative control services - revenue derived from the provision of metering services relating to non-residential customers on low voltage demand network tariffs.

DREV0204 - Revenue from non-residential high voltage demand tariff customers

- Standard control services - revenue received from non-residential high voltage demand tariff customers.
- Alternative control services – revenue derived from the provision of metering services relating to non-residential customers on high voltage demand network tariffs.

DREV0205 - Revenue from unmetered supplies

- Standard control services - revenue received from customers on the network unmetered supply tariffs.
- Alternative control services – revenue received for the provision of public lighting services and control lighting services.

DREV0206 - Revenue from other customers

- Standard control services – not applicable to Aurora.
- Alternative control services – revenue received from the provision of fee based services (special services and quoted services).

2	Explain the source of the information to support the variable

- All data for variables DREV0201 – DREV0206 is sourced from Aurora's market and billing systems.
- For 2013, the metering revenue has been derived from the Regulated Accounts.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

DREV0201 - Revenue from residential customers

Standard Control Services

Revenue received via the following residential tariffs:

- N01 – General Network Residential;
- N05 – Uncontrolled Energy;
- N06 – Controlled Energy;
- N06a – Controlled Energy; and
- N13r – LV ToU Residential.

The following tariffs are available to both residential and non-residential customers:

- N05 – Uncontrolled Energy;
- N06 – Controlled Energy; and
- N06a – Controlled Energy.

Aurora's billing systems captures the installation type of each connection as part of the market standing data. The installation type categorises each connection point based as either:

- Residential; or
- Industrial; or
- Commercial.

For those tariffs available to both residential and non-residential customers, revenue has been apportioned according to the installation type classification at a NMI level.

Alternative Control Services

- Revenue received for the provision of metering services to residential customers only, the primary tariff and NMI installation type has been used to ensure only revenue relating to residential customers has been included in DREV201.

DREV0202 - Revenue from non-residential customers not on demand tariffs

Standard Control Services

Revenue received via the following non-residential tariffs:

- N02 – General Network – Business
- N02a – General Network – Business, Nursing Homes
- N02b – General Network – Business Curtilage
- N08 – LV Day/Night (Irrigation)
- N08a/b – LV Irrigation (ToU)
- N05 – Uncontrolled Energy
- N06 – Controlled Energy
- N06a – Controlled Energy
- N13b/c – LV ToU Business

The following tariffs are available to both residential and non-residential customers:

- N05 – Uncontrolled Energy;
- N06 – Controlled Energy; and
- N06a – Controlled Energy.

Aurora's billing systems captures the installation type of each connection as part of the market standing data. The installation type categorises each connection point based as either:

- Residential; or
- Industrial; or
- Commercial.

For those tariffs available to both residential and non-residential customers, revenue has been apportioned according to the installation type classification at a NMI level.

Alternative Control Services

- Revenue received for the provision of metering services to non-residential customers only, the primary tariff and NMI installation type has been used to ensure only revenue relating to non-residential customers has been included in DREV202.

DREV0203 - Revenue from non-residential low voltage demand tariff customers

Standard Control Services

Revenue received via the following non-residential LV demand tariffs:

- N03 – LV kW Demand
- N09 – LV KVA Demand

Alternative Control Services

- Revenue received for the provision of metering services to non-residential customers on LV demand tariffs only, the primary tariff has been used to ensure only revenue relating to residential customers has been included in DREV203.

DREV0204 - Revenue from non-residential high voltage demand tariff customers

Standard Control Services

Revenue received via the following non-residential HV demand tariffs:

- N10 – HV kVA Demand;
- N10s – HV kVA Specified Demand;
- N11 - HV kW Demand;
- N15 – HV kVA Specified Demand (>2.0 MVA); and
- ITC - Individual Network Tariff Calculations.

Alternative Control Services

- Revenue received for the provision of metering services to non-residential customers on HV demand tariffs only, the primary tariff has been used to ensure only revenue relating to residential customers has been included in DREV204.
- Some sites are being metered via the provision of an unregulated service, hence the differences in the number of tariffs between standard and alternative control.

DREV0205 - Revenue from unmetered supplies

Standard Control Services

Revenue received via the following unmetered supply tariffs:

- N07 – Small LV Unmetered
- N20 – Street lighting

Alternative Control Services

- Revenue received for the provision of public lighting services and contract lighting services. Data has been extracted from Aurora's financial systems, data manipulation not required.

DREV0206 - Revenue from other customers

- Data extracted direct from Aurora's financial systems, data manipulation was not required.

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

Table 2.2 – Revenue grouping by customer type or class

- For 2006 and 2007 the required data is not available from Aurora's market and billing systems.
- For 2013, the metering revenue extracted from the billing system contained data quality issues.

The basis for the estimate

Table 2.2 – Revenue grouping by customer type or class

Estimation approach

- Revenue as recorded in the Regulatory Accounts has been used to estimate the 2006 and 2007 variables.
- The revenue recorded in the Regulatory Accounts has been apportioned across the revenue grouping in accordance with the actual percentage splits for 2008 to 2013 (using a normalised average).
- For 2008, the Regulated Accounts value for metering revenue has been used, allocated across the RIN categories using the base billing data percentages.
- For 2013, the metering revenue from the Regulated Accounts has been apportioned based on the base data used for month end reporting.

Estimation assumptions

- It is assumed that the application of the 2008 to 2013 normalised average is representative of the allocation of revenue across the revenue groupings for 2006 and 2007.

Table 2.3 – Revenue (penalties) allowed (deducted) through incentive schemes

1	Demonstrate how the information provided is consistent with the requirements of the RIN

DREV0301 - EBSS

- Not applicable for Aurora for the Benchmarking RIN back-cast period.

DREV0302 - STPIS

- For financial years 2005/06 to 2007/08 information provided was consistent with the calculation of the distribution annual revenue (MAR) for calendar years 2005 to 2007.
- For 2009/10 to 2012/13 STPIS calculation is not applicable to Aurora.

DREV0303 - Other

- Not applicable for Aurora for the Benchmarking RIN back-cast period.

2	Explain the source of the information to support the variable

DREV0302 - STPIS

- For calendar years 2005, 2006 and 2007, information is sourced from the calculation of the distribution maximum annual revenue (MAR).

3	Explain the methodology applied to provide the required information (inc. any assumptions)

DREV0302 - STPIS

- For calendar years 2005, 2006 and 2007, the values are calculated as per the calculation of the distribution maximum annual revenue (MAR).
- SAIDI and SAIFI value is divided by two to determine the financial year value (it is assumed that these values are split evenly between calendar year).

Template 3 - Opex

Table 3.1 – Opex categories

VARIABLE(S)
3.1.1 – Current opex categories and cost allocations **DOPEX0101 - DOPEX0139** • As per the instructions and definitions, Aurora is required to complete table 3.1.1 where it has been deemed a change has occurred in the annual reporting requirements during the reporting period. **3.1.2 – Historical opex categories and cost allocations** **DOPEX0101A – DOPEX0131C** • Actual data provided is as per the Regulated Accounts/RIN for each applicable year. The regulated accounts have been audited for compliance to the guidelines and the CAM.

1	Demonstrate how the information provided is consistent with the requirements of the RIN
3.1.1 – Current opex categories and cost allocations **DOPEX0101 - DOPEX0139** • Base opex data by work category supporting the annual regulated accounts. This data was the basis for completing the audited and approved regulated accounts for each applicable year. • DBOPEX0125 (fee based) and DBOPEX0126 (quoted services) were previously treated as capital expenditure, and are therefore not included. • DBOPEX0128 (network management) to DBOPEX0139 (other operating costs - not allocated to the distribution) for alternative control services have been estimated using 2012/13 apportionments for the previous regulatory years. **3.1.2 – Historical opex cost categories and cost allocations** **DOPEX0101A – DOPEX0131C** • The actual data provided is per the regulated accounts/Reporting RIN response for each applicable year. • The regulated accounts have been audited for compliance to the guidelines and the CAM.	

2	Explain the source of the information to support the variable

3.1.1 – Current opex categories and cost allocations

DOPEX0101 - DOPEX0139

- Due to different reporting frameworks that applied in each reporting period, there was a requirement to map the reporting categories from previous regulatory periods to be consistent with the reporting categories that applied in 2012/13.
- To achieve this, the base opex data from the regulatory accounts for each year back to 2004/05 has been mapped to the service classifications and reporting categories that applied in 2012/13 using a mapping table by work category.
- Only expenditure classified as regulated services for each of the years 2004/05 to 2011/12 has been reported in the template.
- Public lighting has not been included for reporting periods prior to 2012/13 as this was previously treated as unregulated expenditure.
- There has been no material change in the allocation of overheads over the reporting periods required. As such the cost allocation has remained consistent with the methodology applicable for each reporting year.

3.1.2 – Historical opex cost categories and cost allocations

DOPEX0101A - DOPEX0131C

- Actual data for each of the requested years is sourced from and reconciled to the regulated accounts for each year.
- The audited regulated accounts reconcile to the audited statutory accounts.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

3.1.1 – Current opex categories and cost allocations

DOPEX0101 - DOPEX0139

- The methodology for allocating overhead costs to the service classifications and opex categories is in accordance with Aurora's approved CAM and ICAM.

3.1.2 – Historical opex cost categories and cost allocations

DOPEX0101A - DOPEX0131C

- The methodology for allocating overhead costs to the service classifications and opex categories is in accordance with Aurora's approved CAM and ICAM.

Table 3.2 – Opex consistency

1	Demonstrate how the information provided is consistent with the requirements of the RIN

3.2.1 – Opex consistency – current cost allocation approach
DOPEX0201 – DOPEX0206

- Due to different reporting frameworks that applied in each reporting period, there was a requirement to map the reporting categories from previous regulatory periods to be consistent with the reporting categories that applied in 2012/13 (e.g. standard control and alternative control services).
- To achieve this, the base opex data from the regulatory accounts for each year has been mapped to the service classifications and reporting categories that applied in 2012/13 using a mapping table by work category.
- Only expenditure classified as regulated services for each of the years 2004/05 to 2011/12 has been reported in the template.
- Public lighting has not been included for reporting periods prior to 2012/13 as this was previously treated as unregulated expenditure.
- There has been no material change in the allocation of overheads over the reporting periods. The cost allocation has remained consistent across the reporting periods.
- Table 3.2.1 reconciles to the totals reported in table 3.1.1

3.2.2 – Opex consistency – historical cost allocation approach
DOPEX0201A - DOPEX0206A

- Standard control services are consistent with the classification of services as per the current regulatory control period (2012-2017).
- Alternative control services are consistent with the classification of services as per the current regulatory control period (2012-2017).
- Table 3.2.2 reconciles to the totals reported in table 3.1.2.

DOPEX0205A - Opex for amounts for easement levy or similar direct charges on DNSP

- Costs associated with easement development are capitalised along with the associated project costs.
- Aurora does not have any operating costs associated with this category.

DOPEX0206A - Opex for transmission connection point planning

- Aurora incurs transmission connection point planning costs only as part of the process for establishing a new connection point. These costs are therefore capitalised as part of the wider project.
- Aurora does not have any operating costs associated with this category.

2	Explain the source of the information to support the variable

3.2.2 – Opex consistency – historical cost allocation approach
DOPEX0201A - DOPEX0206A

- Aurora's Regulated Accounts.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

3.2.2 - Opex consistency – historical cost allocation approach
DOPEX0201A - DOPEX0206A

- Expenditure categories assigned to RIN reporting categories in line with the underlying service provision consistent with the current determination classification of services.

DOPEX0203A - Opex for connection services

- Expenditure associated with connection assets only.

Table 3.3 – Provisions

1	Demonstrate how the information provided is consistent with the requirements of the RIN

For variables DOPEX0301 - DOPEX0312J:

- Provision values reconcile to the reported amounts in the annual regulated accounts, noting that in previous regulated accounts the provisions were not split between opex and capex.
- To determine this historic split, the methodology applied in 2012/13 (for Regulatory Year One of the annual Reporting RIN) has been applied.
- Provisions have been split into standard control services, alternative control services and unregulated services.
- The methodology applied is consistent over the regulatory years.

A separate table has been completed for each of the following provisions:

Long Service Leave

- Employees are entitled to 3 months long service leave after 10 years of service.
- Provision is calculated based on percentage probability based on employee's years of service.

Annual Leave

- Provision for employee's entitlement to 20 days annual leave per annum.

RBF (Retirement Benefits Fund defined benefits superannuation)

- Aurora has current and former employees who are members of a defined benefits superannuation scheme which is unfunded; therefore Aurora has a provision on the balance sheet for the liability.

SAF (superannuation accumulation fund)

- Aurora employees who are not part of the defined benefits superannuation are part of an accumulation fund.
- Aurora has an obligation to pay the superannuation to the individual employee's superannuation company.
- The provision represents the superannuation which will be payable on the annual leave and long service leave provisions when they are paid out, plus any superannuation that has been set aside but is yet to be transferred to the individuals superannuation company.

Public Holidays (to provide for public holiday entitlements)

- Sick leave – to provide for 5 days per annum sick leave per employee.
- Time bank - Aurora allows employees to work overtime and claim time in lieu instead of overtime pay, so the provision represents the amount of time in lieu that is outstanding.

Workers compensation

- Aurora has workers compensation insurance. The provision is the amount payable (or receivable) from the insurance company at any point in time.

Redundancy

- A provision for restructuring costs is required where a restructure is committed to but the payments have yet to be made.

Payroll Tax

- Aurora has an obligation to pay payroll tax. The provision represents the payroll tax which will be payable on the annual leave and long service leave provisions when they are paid out.

Others

- Includes superannuation.

2	Explain the source of the information to support the variable

For variables DOPEX0301 - DOPEX0312J:

- Data is sourced from the corporate provisions worksheet contained in the annual regulated accounts for each relevant year.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

For variables DOPEX0301 - DOPEX0312J:

- This table contains the allocation of provision balances and movements to the Distribution Business for each of the provision types.
- To populate the tables the following calculations have been undertaken. This methodology is consistent with the annual reporting RIN for 2012/13.

Allocation across forms of control

- To allocate the provisions balances across the forms of control (SCS, ACS and unregulated), the percentage spend methodology has been applied for each year.
- This process allocates the provisions balances and movements across the forms of control based on the portion of total spend (opex and capex) for each year.

Allocation between opex and capex

- The provisions balances and movements have been allocated between opex and capex using labour dollars as the driver.
- The capex and opex portions are allocated based on the proportion of total labour dollars for both Network and Network services Businesses.
- This methodology is consistent with the methodology used in the 2012-2017 pricing determination.

Table 3.4 – Opex for high voltage customers

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- Only customers that are metered at high voltage and own and operate their own substations have been included in this data series.
- Cost estimates are for operations and maintenance costs only and do not include any capital investments.

2	Explain the source of the information to support the variable

- The number of HV customers for the period covering 2007-13 has been derived from billing records for HV connected NMIs. Where a NMI is recorded as being charged via an HV tariff it has been assumed that the connection is HV and that the customer will have its own substation(s).
- As data is only available from the 2007-08 year it has been assumed that HV connections were consistent prior to this period.
- The number of recorded O/H HV connections and their associated number of transformers for the period 2007-13 has been derived from asset records for HV connected NMIs. U/G HV connection data does not include transformer numbers.
- Where a NMI is recorded as being charged via an HV tariff it has been assumed that the connection is HV and that the customer will have its own substation(s).
- Data prior to the 2008-09 is unreliable and it has been assumed that HV connections were consistent prior to this period.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

- As the number of HV connections from asset data is only for O/H connections it has been assumed that underground connections have a single transformer.
- The number of O/H HV connections was removed from the number of HV connections within the billing data to arrive at the number of U/G private substations.
- The number of O/H private substations was added to this number to arrive at an estimated total number of private substations.
- An estimate of typical substation maintenance costs was prepared based upon Aurora's 2013-14 substation maintenance work program. This annualised cost was then applied to number of private substations to arrive at an estimate of nominal annual costs. These nominal annual costs were deflated to take account of the movement in CPI for each financial year.

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

- Aurora is not privy to the maintenance practices, and therefore costs, of its HV customers. As these 'true' costs are not available, Aurora must estimate the likely costs that would be associated with Aurora's operation and maintenance of these private substations.

The basis for the estimate

Estimation approach

- Determine the number of HV connections that were reported for each financial year and multiply by an average annual maintenance charge to arrive at an estimated annual maintenance cost for those substations.

Estimation assumptions

- The number of HV tariffs is representative of the number of customers with HV connections.
- Each HV connection has a substation that must be maintained and operated.
- Substation maintenance costs are consistent for all private substations.
- Aurora's current substation maintenance program is representative of past Aurora asset management practices and 2013-14 costs will be representative of past costs.
- An average cost has been derived and will be applied to each site.

Reasons why the estimate is the best estimate

- The estimate is based upon Aurora's asset management practices and current internal costs and is therefore representative of the manner in which Aurora would maintain these substations.

Template 4 – Assets (RAB)

Table 4.2 – Asset value roll forward

GLOBAL ASSUMPTIONS – TEMPLATE 4.2 (ASSET VALUE ROLL FORWARD)

Inflation additions (DRAB__02 variables)

- Inflation addition has been applied in a manner consistent with the AER's roll forward model.
- CPI applied consistent with that reported within Aurora's Regulated Accounts and Annual Reporting RIN.
- CPI applied as per table below:

2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13
2.50%	2.07%	2.96%	3.69%	2.11%	2.65%	3.60%	1.63%

- Opening asset value multiple by CPI (as outlined in table above).

Straight line depreciation (DRAB__03 variables)

- Straight line depreciation calculated based on the average remaining asset lives and standard remaining lives (for capex additions).
- The opening 2005-06 asset values was used for the purposes of calculation of the weighted remaining asset lives. The methodology for calculation is consistent with that outlined in the Instructions and Definitions.
- The methodology for calculation of weighted average remaining lives and standards is consistent with that outlined in the instructions and definitions, that is, based on RAB value.

Regulatory depreciation (DRAB__04 variables)

- Straight line depreciation – inflation on the opening RAB.

Closing values (DRAB__07 variables)

- Calculated from the x01 – x06 values.

1	Demonstrate how the information provided is consistent with the requirements of the RIN

OPENING RAB VALUES
(DRAB0201, DRAB0301, DRAB0401, DRAB0501, DRAB0601, DRAB0701, DRAB1001, DRAB1101)

- Actual values reconcile to values previously reported as part of the RAB roll forward underpinning the revenue calculation for the 2012-2017 Determination (with forecasts replaced with actuals).
- 2012-13 capex additions reconciles with the value reporting as part of the 2012-13 Annual Reporting RIN.

DRAB0901 – Meters

- RAB values consistent with the RAB Framework.

The following orange easement variables have had zero entered:

- DRAB0801 - Opening value.
- DRAB0802 - Inflation addition.
- DRAB0805 - Actual additions (recognised in RAB).
- DRAB0806 - Disposals.
- DRAB0807 - Closing value for easements asset value.

As part of the 2012-17 distribution determination, the AER deemed no easements as they are capitalised as part of the project.

- The meter variables (DRAB0901 – DRAB0907) have been estimated (refer to part 4 for estimation methodology).

2	Explain the source of the information to support the variable

OPENING RAB VALUES
DRAB0201, DRAB0301, DRAB0401, DRAB0501, DRAB0601, DRAB0701, DRAB1001, DRAB1101

- Opening RAB value as at the start of the 2005/06 financial year as recorded in Aurora's Regulatory Accounts.
- For the remainder of the period, the opening RAB value has been derived using the RAB roll forward methodology consistently applied by the AER as part of the determination process.

DRAB1201 – Overhead distribution assets less than 33kV (wires and poles)

- Base data sourced from Aurora's Regulated Accounts and Aurora's Annual Reporting RIN.

ADDITIONS AND DISPOSALS:
DRAB0205, DRAB0305, DRAB0405, DRAB0505, DRAB0605, DRAB0705, DRAB1005, DRAB1105
DRAB0206, DRAB0306, DRAB0406, DRAB0506, DRAB0606, DRAB0706, DRAB1006, DRAB1106

- Base data sourced from Aurora's Regulated Accounts and Aurora's Annual reporting RIN.

DRAB0901 - Opening RAB,
DRAB0905 – Actual additions (recognised in RAB),
DRAB0906 – Disposals

- Aurora's Regulatory Accounts for asset additions, disposals data.
- AER's 2012-17 Final Determination - metering RAB valuation.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

Actual additions (recognised in the RAB) (DRAB__05 variables)

- Aurora's asset classes (as reported throughout the 2012-17 Regulatory Determination Process and in the Annual Reporting RIN) have been classified into the Benchmarking RIN reporting asset classes based on the definitions provided.
- The RAB asset classes are in accordance with the Benchmarking RIN chapter 9 instructions and definitions.

Disposals (DRAB__06 variables)

- Up to and including the 2011-12 financial disposal values reported as part of Aurora's regulated accounts reflected the written down value of the asset.
- For the 2012-13 financial year disposals reported as part of the Annual RIN represent proceeds from sale.
- Disposal values have been reported in a manner consistent with the reporting methodology of the year in question.
- The RAB asset classes are in accordance with the Benchmarking RIN chapter 9 instructions and definitions.

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

The meters variables (DRAB0901 – DRAB0907) have been estimated:

- The AER determined a metering opening RAB value at the start of the 2012-17 distribution determination period.
- The RAB revaluation resulted in an inability to utilise actual RAB values as previously recorded in Aurora's Regulatory Accounts.
- As a result, the metering RAB has been calculated using a roll back methodology from the date of the revaluation in accordance with the RAB Framework.

The basis for the estimate

Estimation approach

- RAB roll back methodology applied as at the date of revaluation is consistent with the RAB Framework.
- Additions and inflation have been subtracted from the RAB while depreciation and disposals have been added to the RAB.

The following factors caused the negative opening RAB value:

- Historically, Aurora has not recorded meter disposals for the meter replacement program associated with the introduction of PAYG metering.
- Aurora's metering lives have not been amended to reflect the outcomes of previous OTTER determinations impacting upon depreciation.

Estimation assumptions

- Nil – the actual Regulatory Accounts data applied to the AER meter RAB valuation.

Reasons why the estimate is the best estimate

- The estimation methodology is consistent with the AER's RAB methodology outlined in the instructions and definitions.

Table 4.3 – Total disaggregated RAB values

1	Demonstrate how the information provided is consistent with the requirements of the RIN
•	For the variables DRAB1201 – DRAB1210 (excluding DRAB1207 – easements) the average RAB asset values for the asset class have been calculated. • For DRAB13 - estimated value of capital contributions or contributed assets, the actual capital contributions received have been allocated by the form of control. • DRAB1207 – Easements are not applicable to Aurora (zero entered).
2	Explain the source of the information to support the variable
•	For the variables DRAB1201 – DRAB13 (excluding DRAB1207 – easements) the base data is sourced from Aurora's Regulated Accounts and Aurora's Annual Reporting RIN.
3	Explain the methodology applied to provide the required information (inc. any assumptions)
•	For the variables DRAB1201 – DRAB1210 (excluding DRAB1207 – easements), the values are calculated as the average of the opening and closing RAB values for the relevant Regulatory Year for the asset class. • For DRAB13 (estimated value of capital contributions or contributed assets), the actual capital contributions received have been used (no additional calculations).

Table 4.4 – Asset lives

1	Demonstrate how the information provided is consistent with the requirements of the RIN

Table 4.4.1 - Asset Lives – estimated service life of new assets
Table 4.4.2 - Asset Lives – estimated residual service life

- The variables rely on historical information recorded in Aurora Energy's Regulatory Accounts and information submitted to the AER in Aurora's Reporting RIN response for the 2012-13 Regulatory Year.
- Where asset categories comprise a number of asset classes, consistent with the instructions and definitions the asset lives for the whole category have been calculated by weighting the lives of individual asset classes within that category on the basis of replacement cost.

2	Explain the source of the information to support the variable

Table 4.4.1 - Asset Lives – estimated service life of new assets
Table 4.4.2 - Asset Lives – estimated residual service life

- The asset classes used are the same as the asset classes that are used to describe Aurora's Regulatory Asset Base.
- The standard asset lives applied to each asset class are consistent with Aurora's submissions as part of the AER's 2012 Distribution Determination.
- The asset replacement costs used to derive weighted ages, weighted average useful lives and weighted average residual service lives for each category of asset reflect the optimised replacement cost of the period additions to each asset class reported in Aurora's Regulated Accounts for the back-cast period up to and including 2011-12, with the addition of "Capex by Asset Class" for 2012-13 as reported by Aurora in response to the AER's Reporting RIN for the 2012-13 Regulatory Year.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

Table 4.4.1 - Asset Lives – estimated service life of new assets
Table 4.4.2 - Asset Lives – estimated residual service life

- In order to estimate residual asset lives, for each class of asset a weighted average end of year age has been calculated for every regulatory year in the back-cast period.
- The weighted average age of each asset class reflects the age of the stock of assets in service at the beginning of the back-cast period, plus the additions made in each year of the back-cast period and the age of those assets at the end of each subsequent regulatory year.
- The average age for each asset class is weighted on the basis of the proportional contribution that the additions made in each regulatory year make to the total cumulative replacement cost of that asset class.
- The estimated residual service life for a given asset class is calculated by subtracting the weighted average age of that asset class from the relevant standard asset life.
- It is noted that where the period additions to an asset class are, at the end of any given regulatory year, of an age that exceeds the estimated service life of new assets in that asset class, rather than ascribe a negative residual service life to that asset class, the estimated residual service life of the assets in question is deemed to be nil. This has been done to reflect that, while a negative residual service life may indicate the extent to which an asset is theoretically overdue for replacement, in practice the assets in question simply have no residual service life remaining, and the use of negative residual service lives would distort calculations of collective residual service lives.
- Where an asset category is comprised of a single asset class, the standard operating life of that class of asset is deemed to be the estimated service life of new assets for the corresponding asset category, and the estimated residual service life applying to that asset class for a given regulatory year is also applied to the asset category in question.
- In cases where an asset category comprises a number of asset classes, the weighted average asset ages, useful lives and residual service lives of each asset class making up the asset category, which have been calculated separately as described above, are themselves averaged in order to derive an average useful asset life and estimated residual service life for the asset category as a whole.
- This has been done by weighting each asset class' average age, useful life and estimated residual service life on the basis of the optimised replacement cost of each asset class as a percentage of the combined replacement cost of the asset category in question.

Template 5 – Operational Data

Table 5.1 – Energy delivery

GLOBAL ASSUMPTIONS – TEMPLATE 5.1 (Energy Delivery)

The time of use parameters for Table 5.1 are outlined in the table below:

Time Period	Tariff Rate
Week Day (07:00 – 22:00) (Monday – Friday)	Peak
Weekend Day (07:00 – 22:00) (Saturday and Sunday)	Shoulder
Any Day (22:00 – 24:00) (Monday – Sunday)	Off-Peak
Any Day (0:00 – 07:00) (Monday – Sunday)	Off-Peak

Zero entered for the following variables:

- DOPED0301 - Energy into the DNSP at on-peak times.
- DOPED0302 - Energy into DNSP network at shoulder times.
- DOPED0303 - Energy into DNSP network at off-peak times.

DATA NOT AVAILABLE (2006-2011):

- DOPED0405 – Energy into DNSP at on-peak time for residential embedded generation.
- DOPED0406 – Energy into DNSP at shoulder times for residential embedded generation.
- DOPED0407 – Energy into DNSP at off-peak times for residential embedded generation.

Residential embedded generation connections represent basic metered sites therefore Aurora is unable to report based on time intervals.

1	Demonstrate how the information provided is consistent with the requirements of the RIN

DOPED01 – Energy delivery

- Total energy delivered as measured at the customer’s premises (transported out of Aurora Energy’s network).

DOPED0201 – Energy delivery where time of use is not a determinant

- Total energy delivered as measured at the customer’s premises (transported out of Aurora Energy’s network), where customers have been assigned to network tariffs where time of use is not a determinant.

DOPED0202 – Energy delivery at on-peak times

- Total energy delivered as measured at the customer’s premises (transported out of Aurora Energy’s network), where customers have been assigned to time of use network tariffs.

DOPED0203 – Energy delivery at shoulder times

- Total energy delivered as measured at the customer’s premises (transported out of Aurora Energy’s network), where customers have been assigned to time of use network tariffs.

DOPED0204 – Energy delivery at off-peak times

- Total energy delivered as measured at the customer’s premises (transported out of Aurora Energy’s network), where customers have been assigned to time of use network tariffs.

DOPED0205 – Controlled load energy deliveries

- Total energy delivered as measured at the customer’s premises (transported out of Aurora Energy’s network), where customers have been assigned to Aurora’s controlled load network tariffs.

DOPED0206 – Energy delivery to unmetered supplies

- Total energy delivered as measured in relation to Aurora’s unmetered supply tariffs.

The following variables are not applicable (zero has been input), as Aurora TUoS charges are not based on time of use parameters (therefore market data is not reported in a time of use manner):

- DOPED0301 - Energy into the DNSP at on-peak times.
- DOPED0302 - Energy into DNSP network at shoulder times.
- DOPED0303 - Energy into DNSP network at off-peak times.

DOPED0304 - Energy received from TNSP and other DNSPs not included in the above categories

- Total energy transported out of Aurora Energy’s Network (GWh) as reported at the connection point with Transend Networks Pty Ltd.

DOPED0401 – Energy into DNSP at on-peak time for non-residential embedded generation

- Energy delivered (for on-peak periods) as recorded at interval metered non-residential embedded generation connections.

DOPED0402 – Energy into DNSP at shoulder times for non-residential embedded generation

- Energy delivered (for shoulder periods) as recorded at interval metered non-residential embedded generation connections.

DOPED0403 – Energy into DNSP at off-peak times for non-residential embedded generation

- Energy delivered (for off-peak periods) as recorded at interval metered non-residential embedded generation connections.

DOPED0404 – Energy received from embedded generation not included in above categories from non-residential embedded generation

- Energy received from embedded generation non-residential customers (basic metered).

DOPED0408 – Energy received from embedded generation not included in above categories from residential embedded generation

- Energy received from embedded generation residential customers (basic metered).

DOPED0501 - Residential customers energy deliveries

- Total energy delivered as measured at the customer's premises (transported out of Aurora Energy's network), where residential customers have been assigned to energy based network tariffs.

DOPED0502 – Non-residential customers not on demand tariffs energy deliveries

- Total energy delivered as measured at the customer's premises (transported out of Aurora Energy's network), where non-residential customers have been assigned to energy based network tariffs.

DOPED0503 - Non-residential low voltage demand tariff customers energy deliveries

- Total energy delivered as measured at the customer's premises (transported out of Aurora Energy's network), where non-residential customers have been assigned to network low voltage demand based tariffs.

DOPED0504 - Non-residential high voltage demand tariff customers energy deliveries

- Total energy delivered as measured at the customer's premises (transported out of Aurora Energy's network), where non-residential customers have been assigned to high voltage demand based network tariffs.

DOPED0505 – Other Customer Class Energy Deliveries

- Total energy recorded for other customer classes including street lighting and unmetered supply.

2	Explain the source of the information to support the variable

DOPED0201 – DOPED0206

- Data for these variables is sourced from Aurora's market and billing systems.

DOPED0304 - energy received from TNSP and other DNSPs not included in the above categories

- Sourced from Transend's metering and billing system.

DOPED0401 - DOPED0404, DOPED0408, DOPED0501 - DOPED0505

- Data for these variables is sourced from Aurora's market systems.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

DOPED01 – Energy delivery

- Total Energy delivered (GWh) – sum of variables DOPED0201 – DOPED0206.

DOPED0201 – Energy delivery where time of use is not a determinant

Total energy delivered as measured at the customer connection point for the following network tariffs:

- N01 – General Network – Residential
- N02 – General Network – Business
- N02a – General Network – Business, Nursing Homes
- N02b – General Network – Business, Curtilage
- N03 – LV kW Demand
- N05 – Uncontrolled Energy
- N06 – Controlled Energy
- N06a – LV Controlled Energy
- N07 – Small LV Unmetered
- N08 – LV Day/Night Irrigation
- N09 – LV kVA Demand
- N11 – HV kW Demand
- N10 – HV kVA Demand
- N13 – LV PAYG

DOPED0202 – Energy delivery at on-peak times

Data extracted from Aurora's market and billing systems by time of use parameter consistent with the peak assumption outlined above. Aurora's time of use tariffs include:

- N08a - LV Irrigation (ToU)
- N08b – LV Irrigation (ToU)
- N10s – HV kVA Specified Demand
- N13b – LV ToU - Business
- N13c – LV ToU - Business
- N13r – LV ToU - Residential
- N15 – HV kVA Specified Demand (>2.0MVA)
- ITC – Individual Network Tariff Calculation

DOPED0203 – Energy delivery at shoulder times

Data extracted from Aurora's market and billing systems by time of use parameter consistent with the shoulder assumption outlined above. Aurora's time of use tariffs include:

- N08a - LV Irrigation (ToU)
- N08b – LV Irrigation (ToU)
- N10s – HV kVA Specified Demand
- N13b - LV ToU - Business
- N13c – LV ToU - Business
- N13r – LV ToU - Residential
- N15 – HV kVA Specified Demand (>2.0MVA)
- ITC – Individual Network Tariff Calculation

DOPED0204 – Energy delivery at off-peak times
Data extracted from Aurora's market and billing systems by time of use parameter consistent with the off-peak assumption outlined above. Aurora's time of use tariffs include:

- N08a - LV Irrigation (ToU)
- N08b – LV Irrigation (ToU)
- N10s – HV kVA Specified Demand
- N13b - LV ToU - Business
- N13c – LV ToU - Business
- N13r – LV ToU - Residential
- N15 – HV kVA Specified Demand (>2.0MVA)
- ITC – Individual Network Tariff Calculation

DOPED0205 – Controlled load energy deliveries
Energy delivered for network controlled energy tariffs, this includes the following Aurora tariffs:

- N06 – Controlled Energy; and
- N06a - LV Controlled Energy.

DOPED0206 – Energy delivery to unmetered supplies
Total energy delivered as recorded for the following unmetered supply tariffs:

- N07 – Small LV Unmetered; and
- N20 – Street Lighting.

DOPED0304 - Energy received from TNSP and other DNSPs not included in the above categories

- Sum of energy delivered for each financial year.

DOPED0401 – DOPED0403

- Aurora Energy has reported energy received from non-residential embedded generation by time of receipt, based on the time of use periods.

DOPED0404 – Energy received from embedded generation not included in above categories from non-residential embedded generation
DOPED0408 – Energy received from embedded generation not included in above categories from residential embedded generation

- Energy received from non-residential embedded generation (basic metered), not captured in the above categories.

DOPED0501 - Residential customers energy deliveries

Energy delivered as recorded against the following residential tariffs:

- N01 – General Network Residential;
- N05 – Uncontrolled Energy;
- N06 – Controlled Energy;
- N06a – Controlled Energy;
- N13 – LV PAYG; and
- N13r – LV ToU Residential.

The following tariffs are available to both residential and non-residential customers:

- N05 – Uncontrolled Energy;
- N06 – Controlled Energy; and
- N06a – Controlled Energy.

Aurora's billing systems captures the installation type of each connection as part of the market standing data. The installation type categorises each connection point based as either:

- Residential; or
- Industrial; or
- Commercial.

For those tariffs available to both residential and non-residential customers, energy delivered has been apportioned according to the installation type classification at a NMI level.

DOPED0502 – Non-residential customers not on demand tariffs energy deliveries

Total energy delivered as recorded against the following non-residential energy based tariffs:

- N02 – General Network – Business
- N02a – General Network – Business, Nursing Homes
- N02b – General Network – Business Curtilage
- N08 – LV Day/Night (Irrigation)
- N08a/b – LV Irrigation (ToU)
- N05 – Uncontrolled Energy
- N06 – Controlled Energy
- N06a – Controlled Energy
- N13b/c – LV ToU Business

The following tariffs are available to both residential and non-residential customers:

- N05 – Uncontrolled Energy;
- N06 – Controlled Energy; and
- N06a – Controlled Energy.

Aurora's billing systems captures the installation type of each connection as part of the market standing data. The installation type categorises each connection point based as either:

- Residential; or
- Industrial; or
- Commercial.

For those tariffs available to both residential and non-residential customers, total energy has been apportioned according to the installation type classification at a NMI level.

DOPED0503 - Non-residential low voltage demand tariff customers energy deliveries

Total energy delivered as recorded against the following non-residential low voltage demand based tariffs:

- N03 – LV kW Demand
- N09 – LV kVA Demand

DOPED0504 - Non-residential high voltage demand tariff customers energy deliveries

Total energy delivered as recorded against the following non-residential high voltage demand based tariffs:

- N10 – HV kVA Demand;
- N10s – HV kVA Specified Demand;
- N11 - HV kW Demand;
- N15 – HV kVA Specified Demand (>2.0 MVA); and

- ITC - Individual Network Tariff Calculations.

DOPED0505 – Other Customer Class Energy Deliveries

Total energy delivered as recorded against the following network tariffs:

- N07 – Small LV Unmetered
- N20 – Street lighting

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

Table 5.1.1 – Energy grouping - delivery by chargeable quantity

Table 5.1.2 – Energy - received from TNSP and other DNSPs by time of receipt

Table 5.1.3 - Energy - received into DNSP system from embedded generation by time of receipt

Table 5.1.4 – Energy - received into DNSP system from embedded generation by time of receipt

- Actual data unavailable for 2006 and 2007, at the required level of detail for the requested groupings.

The basis for the estimate

Estimation approach and assumptions

Table 5.1.1 – Energy grouping - delivery by chargeable quantity

Table 5.1.2 – Energy - received from TNSP and other DNSPs by time of receipt

Table 5.1.4 – Energy - received into DNSP system from embedded generation by time of receipt

- The Transend purchased load (sourced from the Transend billing portal) has been adjusted with the average distribution loss for the period (where actual data is available), then apportioned to the required template groupings based on the actual average percentage split for the 2008 to 2013 data.
- The data has been It is assumed that the average for 2008 to 2013 is an accurate representation for 2006 and 2007.

Table 5.1.3 - Energy - received into DNSP system from embedded generation by time of receipt

- For 2006 and 2007, the data that was recorded during these periods has been provided.
- Given the data sets for these years may be incomplete, Aurora would class the data for these two years as estimates.

Table 5.2.1 – Distribution customer numbers by customer type or class

Table 5.2.2 – Distribution customer numbers by location on the network

1	Demonstrate how the information provided is consistent with the requirements of the RIN

Aurora has provided customer numbers in accordance with the category definitions in chapter 9.

Table 5.2.1 – Distribution customers by customer type or class

- Residential customer numbers.
- Non-residential customers not on demand tariff customer numbers.
- Low voltage demand tariff customer numbers.
- Unmetered customer numbers.
- Other customer numbers.

Table 5.2.2 – Distribution customers by location on the network

- Customers on CBD network.
- Customers on urban network.
- Customers on short rural network.
- Customers on long rural network.

As requested by the AER, Aurora has also supplied distribution customer numbers by location on network in accordance with the TEC supply reliability categories (provided in Template 5a):

- Critical infrastructure.
- High density commercial.
- Urban.
- High density rural.
- Low density rural.

All of Aurora Energy's unmetered customers have a National Metering Identifier (NMI).

A table has been provided at the end of this section detailing the number of unmetered connections (excluding public lighting connections) that are included in the customer numbers for tables 5.2.1 and 5.2.2.

2	Explain the source of the information to support the variable

- Meter data management system.
- Spatial data warehouse.
- Gentrack.
- WASP outage management system.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

- NMIs were extracted from the spatial data warehouse where the NMI was connected to a feeder and a reliability category.
- NMIs on the Bass Strait Islands and those NMIs with statuses of 'extinct' or 'greenfield' are excluded.
- NMI numbers are taken at the end of a financial year for 2010/11, 2011/12 and 2012/13 from the spatial data warehouse. This allows the NMIs to be sorted into their respective feeder and reliability categories for reporting.
- NMI numbers are then taken at the end of the financial year from the meter data management system – which holds all the NMIs and will identify the excess that have not been connected to a feeder or reliability category.
- These excess NMIs are then spread across the feeder and reliability category populations.
- Once the NMI figures are known 2010/11, 2011/12 and 2012/13 the average growth from these years is taken and previous years are estimated using this growth figure.

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

- The NMI data prior to 2010/11 is incomplete.

The basis for the estimate

Estimation approach

- Find the level of growth in the 3 years with accurate data.
- Apply same % of growth backwards to estimate data for 2006 – 2010.

Estimation assumptions

- All NMIs except those on Bass Strait Islands.

Reasons why the estimate is the best estimate

- This is the best estimate to be made using valid data held by Aurora for 2011 to 2013.

Unmetered connections (excluding public lighting connections)

	Regulatory Year							
	2006	2007	2008	2009	2010	2011	2012	2013
Number of unmetered connections reported in customer numbers in the economic benchmarking RIN	1,280	1,280	1,280	1,280	1,307	1,331	1,325	1,339
Unmetered connections not reported in customer numbers in the economic benchmarking RIN	0	0	0	0	0	0	0	0
Total unmetered connections	1,280	1,280	1,280	1,280	1,307	1,331	1,325	1,339

Table 5.3 – System demand (excluding 5.3.6, 5.3.7)

NOTE	Annual System Maximum Demand Characteristics at the Zone Substation Level

- Aurora highlights that the maximum demand values aggregated at the zone substation level, provided in tables 5.3.1 and 5.3.3, are potentially misleading due to Aurora's unusual network topology and lower number of zone substations (relative to other DNSPs).
- This observation extends to those variables that utilise the maximum demand values at the zone substation level as a component of their calculation (e.g. DQS04 – capacity utilisation, DOEF0103 – demand density).

VARIABLE(S)

RAW SYSTEM ANNUAL MAXIMUM DEMAND VARIABLES

Table 5.3.1

Annual system maximum demand characteristics at the zone substation level – MW measure

- DOPSD0101 - Non-coincident Summated Raw System Annual Maximum Demand
- DOPSD0104 - Coincident Raw System Annual Maximum Demand

Table 5.3.2

Annual system maximum demand characteristics at the transmission connection point – MW measure

- DOPSD0107 - Non-coincident Summated Raw System Annual Maximum Demand
- DOPSD0110 - Coincident Raw System Annual Maximum Demand

Table 5.3.3

Annual system maximum demand characteristics at the zone substation level – MVA measure

- DOPSD0201 - Non–coincident Summated Raw System Annual Maximum Demand
- DOPSD0204 - Coincident Raw System Annual Maximum Demand

Table 5.3.4

Annual system maximum demand characteristics at the transmission connection point – MVA measure

- DOPSD0207 - Non–coincident Summated Raw System Annual Maximum Demand
- DOPSD0210 - Coincident Raw System Annual Maximum Demand

1	Demonstrate how the information provided is consistent with the requirements of the RIN

NON-COINCIDENT SUMMATED RAW SYSTEM ANNUAL MAXIMUM DEMANDS

- The non-coincident raw system annual maximum demands are the actual unadjusted summation of actual raw annual maximum demands at the zone substation or transmission connection point, irrespective of when they occur within the year.
- These maximum demands have not been adjusted for embedded generation.

COINCIDENT RAW SYSTEM ANNUAL MAXIMUM DEMANDS

- The coincident raw system annual maximum demands are the actual unadjusted summation of actual raw demands for the zone substation or transmission connection point, at the time when the summation is greatest.

2	Explain the source of the information to support the variable
3	Explain the methodology applied to provide the required information (inc. any assumptions)

- Raw demand data is sourced from Transend.
- Half hourly data is collected at the connection points by the Transend metering systems and supplied to Aurora.
- Aurora consolidate the raw data, then extract the coincident and non-coincident maximum demands from the data sets.
- The maximum demands generated from the raw data are incorporated into the Aurora load forecasting process.
- The data used to populate the template variables is sourced from the latest version of this Aurora load forecast.

VARIABLE(S)
WEATHER ADJUSTED ANNUAL MAXIMUM DEMANDS (10% and 50% POE) **Table 5.3.1** **Annual system maximum demand characteristics at the zone substation level – MW measure** • DOPSD0102 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE • DOPSD0103 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE • DOPSD0105 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE • DOPSD0106 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE **Table 5.3.2** **Annual system maximum demand characteristics at the transmission connection point – MW measure** • DOPSD0108 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE • DOPSD0109 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE • DOPSD0111 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE • DOPSD0112 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE **Table 5.3.3** **Annual system maximum demand characteristics at the zone substation level – MVA measure** • DOPSD0202 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE • DOPSD0203 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE • DOPSD0205 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE • DOPSD0206 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE **Table 5.3.4** **Annual system maximum demand characteristics at the transmission connection point – MVA measure** • DOPSD0208 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE • DOPSD0209 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE • DOPSD0211 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE • DOPSD0212 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- Coincident weather adjusted system annual maximum demands are the summation of the weather adjusted annual maximum demands for the zone substation or transmission connection point, at the 10% or 50% POE level, at the time when the summation is the greatest.
- Non-coincident weather adjusted system annual maximum demands are the summation of weather adjusted annual maximum demands for the zone substation or transmission connection point, at the 10% or 50% POE level, irrespective of when they occur within the year.

2	Explain the source of the information to support the variable
3	Explain the methodology applied to provide the required information (inc. any assumptions)

- Raw demand data is sourced from Transend.
- Half hourly data is collected at the connection points by the Transend metering systems and supplied to Aurora.
- Aurora consolidate the raw data, then extract the coincident and non-coincident maximum demands from the data sets.
- Weather data is retrieved from the Bureau of Meteorology, for the weather stations used in the weather adjustment process.
- The weather data is used to establish annual comparison to average and demand sensitivity to weather, in accordance with the in accordance with the internal Network Planning weather adjustment methodology.
- This data and supporting methodology is then used to establish 10% and 50% POE demand equivalents.
- The weather adjusted maximum demands generated in accordance with the weather adjustment methodology are incorporated into the Aurora load forecasting process.
- The data used to populate the template variables is sourced from the latest version of this Aurora load forecast.

VARIABLE(S)	
POWER FACTOR CONVERSIONS (between MVA and MW) **Table 5.3.5 Power factor conversion between MVA and MW** **ACTUAL DATA** • DOPSD0301 - Average overall network power factor conversion between MVA and MW • DOPSD0303 - Average power factor conversion for 11 kV lines • DOPSD0305 - Average power factor conversion for 22 kV lines • DOPSD0306 - Average power factor conversion for 33 kV lines **Aurora has added the following variable:** • DOPSD0309 - Average power factor conversion for 44 kV lines **ESTIMATED DATA** • DOPSD0302 – Average power factor conversion for low voltage distribution lines • DOPSD0304 – Average power factor conversion for SWER lines **The following variables are not applicable to Aurora:** • DOPSD0307 – Average power factor conversion for 66 kV lines • DOPSD0308 – Average power factor conversion for 132 kV lines	
1	Demonstrate how the information provided is consistent with the requirements of the RIN
• For the actual data variables (DOPSD0301, DOPSD0303, DOPSD0305, DOPSD0306) Aurora has actual data for MVA and MW throughput, the power factors are calculated in accordance with the instructions and definitions (total MW divided by total MVA). • For the estimated variables, where Aurora does not have actual MVA and MW throughput data, an engineering estimate is provided. • As requested by the template, Aurora has added an additional variable: • DOPSD0309 – Average power factor conversion for 44kV lines.	

2	Explain the source of the information to support the variable
3	Explain the methodology applied to provide the required information (inc. any assumptions)

ACTUAL DATA

- Raw demand data is sourced from Transend.
- Half hourly data is collected at the connection points by the Transend metering systems and supplied to Aurora.
- Aurora consolidate the raw data, then extract the coincident and non-coincident maximum demands from the data sets.
- The maximum demands and power factors generated from the raw data are incorporated into the Aurora load forecasting process.
- Power factors are calculated on an annual basis from the previously calculated maximum demands, and incorporated into the Aurora load forecast.
- The data used to populate the template variables is sourced from the latest version of this Aurora load forecast.

DOPSD0301 - Average overall network power factor conversion between MVA and MW

- Coincident raw system annual maximum demand (DOPSD0110) divided by coincident raw system annual maximum demand (DOPSD0210).

DOPSD0303 - Average power factor conversion for 11 kV lines

- Sum of historical system coincident peak demands (MW) (for the 11kV terminal stations and zone substations) divided by the sum of historical system coincident peak demands (for 11kV terminal stations and zone substations).

DOPSD0305 - Average power factor conversion for 22 kV lines

- Sum of historical system coincident peak demands (MW) (for the 22kV terminal stations and zone substations) divided by the sum of historical system coincident peak demands (for 22kV terminal stations and zone substations).

DOPSD0306 - Average power factor conversion for 33 kV lines

- Sum of historical system coincident peak demands (MW) (for the 33kV terminal stations and zone substations) divided by the sum of historical system coincident peak demands (for 33kV terminal stations and zone substations).

DOPSD0309 - Average power factor conversion for 44 kV lines

- Sum of historical system coincident peak demands (MW) (for the 44kV terminal stations and zone substations) divided by the sum of historical system coincident peak demands (for 44kV terminal stations and zone substations).

ESTIMATED DATA

DOPSD0302 – Average power factor conversion for low voltage distribution lines

- Coincident raw system annual maximum demand (DOPSD0110) divided by coincident raw system annual maximum demand (DOPSD0210).

DOPSD0304 – Average power factor conversion for SWER lines

- Sum of historical system coincident peak demands (MW) (for the 22kV terminal stations and zone substations) divided by the sum of historical system coincident peak demands (for 22kV terminal stations and zone substations).

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

Systems are not in place to capture the detailed level of actual data required to calculate power factors for:

- DOPSD0302 – Average power factor conversion for low voltage distribution lines.
- DOPSD0304 – Average power factor conversion for SWER lines.

The basis for the estimate

Estimation approach and assumptions

DOPSD0302 – Average power factor conversion for low voltage distribution lines

- The approach to estimate the average power factor conversion for low voltage distribution lines is based on an engineering estimate that the low voltage distribution lines generally replicate the overall network.
- The average overall network power factor conversion has been replicated for use as an engineering estimate for the low voltage distribution lines.

DOPSD0304 – Average power factor conversion for SWER lines

- The approach to estimate the average power factor conversion for SWER lines is based on an engineering estimate that greater than 80% of the SWER lines are 22 kV.
- The average power factor conversion for 22 kV lines has been used as an engineering estimate for the average power factor conversion for SWER lines.

Reasons why the estimate is the best estimate

DOPSD0302 – Average power factor conversion for low voltage distribution lines

- The best engineering estimate is that the average overall network power factor conversion is the most reasonable proxy for the low voltage distribution lines average power factor conversion.

DOPSD0304 – Average power factor conversion for SWER lines

- Given the high percentage of SWER lines that are 22 kV (greater than 80%), it is considered that replicating the 22 kV average power factor conversion is the best engineering proxy for the SWER lines.

Table 5.3.6 and 5.3.7 – Demand supplied (for customers charged on this basis – MW or MVA)

VARIABLES	
• Table 5.3.6 Demand supplied (for customers charged on this basis) – MW measure • Table 5.3.7 Demand supplied (for customers charged on this basis) – MVA measure	
1	Demonstrate how the information provided is consistent with the requirements of the RIN

Table 5.3.6 Demand supplied (for customers charged on this basis) – MW measure

DOPSD0401 – Summated Chargeable Contracted Maximum Demand

- No MW tariff with chargeable maximum demand component.

DOPSD0402 – Summated Chargeable Measured Maximum Demand

- Total chargeable contracted measured maximum demand as recorded in relation to customers assigned to network demand based tariffs (as measured in kW).

Table 5.3.7 Demand supplied (for customers charged on this basis) – MVA measure

DOPSD0403 – Summated Contracted Measured Maximum Demand

- Total chargeable contracted maximum demand as recorded in relation to customers assigned to network demand based tariffs (as measured in kVA).

DOPSD0404 – Summated Chargeable Measured Maximum Demand

- Total chargeable contracted measured maximum demand as recorded in relation to customers assigned to network demand based tariffs (as measured in kVA).

2	Explain the source of the information to support the variable

- All data for variables DOPSD0402 - DOPSD0404 been extracted from Aurora's Market Systems.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

DOPSD0402 – Summated Chargeable Measured Maximum Demand

Data extracted was based on the below tariffs for all demand steps:

- N03 – LV kW Demand
- N11 – HV kW Demand

DOPSD0403 – Summated Contracted Measured Maximum Demand

Data extracted was based on the below tariffs, based on excess demand, overrun demand and allowable excess demand:

- N10s – HV kVA Specified Demand;
- N15 – HV kVA Specified Demand (>2 MVA); and
- ITC – Individual Network Tariff Calculation.

DOPSD0404 – Summated Chargeable Measured Maximum Demand

Data extracted was based on the below tariffs, based on excess demand, overrun demand and allowable excess demand:

- N09 – LV kVA Demand; and
- N10 – HV kVA Demand.

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

DOPSD0402 – Summated Chargeable Measured Maximum Demand

DOPSD0403 – Summated Contracted Measured Maximum Demand

DOPSD0404 – Summated Chargeable Measured Maximum Demand

- Actual data not available for 2006 and 2007.

The basis for the estimate

DOPSD0402 – Summated Chargeable Measured Maximum Demand

DOPSD0403 – Summated Contracted Measured Maximum Demand

DOPSD0404 – Summated Chargeable Measured Maximum Demand

Estimation approach & assumptions

- A trendline has been used to complete the 2006 and 2007 variable values.
- It is assumed that the values for 2006 and 2007 fit the linear trendline for the 2008 to 2013 actual values.

Template 6 – Physical Assets

Table 6.1 – Network capacities variables

TEMPLATE	6 – Physical assets
TABLES	6.1.1 - Overhead network length of circuit at each voltage (DPA0101 - DPA0110) 6.1.2 - Underground network circuit length at each voltage (DPA0201 – DPA0207)

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- Total circuit length of Aurora owned conductors and cables by voltage level.
- Dual circuits are counted as two lines.

6.1.1 - Overhead network length of circuit at each voltage
Aurora added variables:

- DPA0108 – Overhead 2.2 kV
- DPA0109 – Overhead 6.6 kV
- DPA0110 – Overhead 44 kV

6.1.2 - Underground network circuit length at each voltage

Aurora added variables:

- DPA0207 – Underground 6.6 kV

2	Explain the source of the information to support the variable

The data is sourced from the Asset Investment & Performance asset history data warehouse.

The following asset history schemas were utilised:

- Asset_History.HV_COND
- Asset_History.HV_COND_ASSET
- Asset_History.LV_COND

3	Explain the methodology applied to provide the required information (inc. any assumptions)

- Conductor and cable line length data extracted using sql query file.
- The install date field was used to identify when conductors/cables were installed in the network where available. All records with null dates were counted for all years.
- HV lines are only those classified as owned by Aurora.
- LV lines are all LV spans and cables include all identified (some do not have defined owners associated in the asset information).

TEMPLATE	6 – Physical assets
TABLES	Table 6.1.3 - Estimated overhead network weighted average MVA capacity by voltage class (DPA0302 - DPA0309) Table 6.1.4 - Estimated underground network weighted average MVA capacity by voltage class (DPA0402 - DPA0407)

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- The variables provide weighted average MVA capacity by voltage class.

2	Explain the source of the information to support the variable

The data is sourced from the Asset Investment & Performance asset history data warehouse.

The following asset history schemas were utilised:

- Asset_History.HV_COND
- Asset_History.HV_COND_CONFIG
- Asset_History.HV_COND_ASSET
- Asset_History.HV_FEEDER
- Asset_History.SUBSTATION

The cable feeder tail rating by substation is derived from the 2013 Aurora Distribution System Planning Report – prepared by the Network Planning Team of the Distribution Business.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

- Summer and winter feeder tail ratings provided by Aurora Network Planning.
- Maximum rating for base/peak and winter/summer calculated.
- Modifications were made to North Hobart feeders to take average rating due to unusual feeder configuration.
- Feeder lengths by OH and UG extracted using SQL query file.
- Data extracted into worksheet.
- Columns M – T calculated by looking up max rating in "DSPR report W & S" worksheet, converting into MVA and then multiplying MVA rating by overhead and underground lengths in each financial year.
- New worksheet created with two pivots, one for total line lengths and total MVA ratings by voltage and owner and then MVA rating/line length to give weighted average.
- Data prior to 2007/2008 is unavailable (used 2007/2008 values).
- Because feeder tail ratings were used, there are no ratings for SWER as Aurora has no SWER lines that originate from a substation.

4	FOR ESTIMATES ONLY
Why was it not possible to use actual information?	
Table 6.1.3 Estimated overhead network weighted average MVA capacity by voltage class Table 6.1.4 Estimated underground network weighted average MVA capacity by voltage class • Data prior to 2008 is unavailable. (used 2007/2008 values).	
Estimation approach • The values for 2008 have been backcast for 2006 and 2007. **Reasons why the estimate is the best estimate** • The 2008 values are a reasonable replication of the values for 2006 and 2007.	

Table 6.2 – Transformer capacities variables

TEMPLATE	6 – Physical assets
TABLES	Table 6.2.1 - Distribution transformer total installed capacity (DPA0501 – DPA0503)

1	Demonstrate how the information provided is consistent with the requirements of the RIN
• Aurora has reported total installed distribution transformer capacity as the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer.	
2	Explain the source of the information to support the variable
The following asset history schemas were utilised from the Asset Investment & Performance asset history data warehouse: • Asset_History.hv_load_tran Aurora Distribution Business billing data.	
3	Explain the methodology applied to provide the required information (inc. any assumptions)
DPA0501 – Distribution transformer capacity owned by utility • Distribution transformer capacities extracted using sql query file. • Data extracted into worksheet with the average cold spare capacity added to the installed capacity. **DPA0502 – Distribution transformer capacity owned by high voltage customers** • Transformer capacity owned by customers at HV not available – used MD of HV customers as a proxy. • Received MD data from Aurora DB Billing team. • Filtered by HV tariffs and summed max kVA for each FY available. • Where max kVA values were in kW, a PF of 1 was used due to the small volume of these records. • No data available prior to 2007/2008 so values from 2007/2008 were used for prior years. **DPA0503 – Cold spare capacity included in DPA0501** • Received average cold spare capacity holdings from Aurora stores. • Assumed that this number would not fluctuate from year to year as these are regular spares holdings.	

4	FOR ESTIMATES ONLY
Why was it not possible to use actual information?	

DPA0502

- Transformer capacity owned by HV customers is not available.

Estimation basis

- Used MD of HV customers as a proxy.

Estimation approach and assumptions

- Received MD data from Aurora Distribution Business Billing Team.
- Filtered by HV tariffs and summed max kVA for each FY available.
- Where max kVA values were in kW, a PF of 1 was used due to the small volume of these records.
- No data available prior to 2007/2008 so values from 2007/2008 were used for prior years.

Reasons why the estimate is the best estimate

- The estimation approach is in accordance with the preferred estimation method (p.33 of the instructions and definitions).

TEMPLATE	6 – Physical assets
TABLES	Table 6.2.2 - Zone substation transformer capacity (DPA0601 – DPA0605) Table 6.2.3 - Distribution – other transformer capacity (new table added)

1 Demonstrate how the information provided is consistent with the requirements of the RIN

DPA0601 and DPA0602 are zero as Aurora does not have any zone transformers that meet these conditions.

DPA0603 - Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage

- Reports total installed capacity where only a single step of transformation is applied before reaching the distribution voltage.

DPA0605 - Cold spare capacity of zone substation transformers included in DPA0604

- Reports total cold spare capacity included in the total zone substation transformer capacity.

New table 6.2.3 (distribution – other transformer capacity) created for Aurora's rural zone transformers – classified "distribution – other" by the AER.

2 Explain the source of the information to support the variable

- Aurora management plan for zone substations (2013/14).

3 Explain the methodology applied to provide the required information (inc. any assumptions)

- Current zone transformers and rural zone transformers extracted from Aurora zone substations management plan.

Table 6.3 – Public lighting

VARIABLE(S)
DPA0701 – Public lighting luminaires DPA0702 – Public lighting poles

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- The number of public lighting luminaires and public lighting poles includes both the assets owned by Aurora and assets operated and maintained by Aurora (but not owned by Aurora).
- The number of poles includes only those poles used exclusively for public lighting.

2	Explain the source of the information to support the variable

The data for table 6.3 is sourced from:

- Spatial data warehouse (SAM schema, UMS view).
- WASP (WASP_NET_Live Database, dbo_Assets table).

3	Explain the methodology applied to provide the required information (inc. any assumptions)

DPA0701 - Public lighting luminaries

- From the UMS view a current total count of luminaries where the street lighting type = 'public road lighting' (at February 2014).
- Using the same criteria, the number of new luminaries installed in each financial year was subtracted from the February 2014 baseline total giving the total number of luminaries for that financial year.

DPA0702 - Public lighting poles

- The current total count of standalone streetlight poles where type = 'public road lighting' and the related pole owner = 'Aurora Surcharge', 'Private', 'City Councils' and 'Telstra'.
- Also luminaries that are on poles that Aurora cannot relate to an owner (from above list) were deemed to be stand-alone street light poles and included in the count.
- Then the number of new luminaries by financial year on poles with pole owner = 'Aurora Surcharge', 'Private', 'City Councils' and 'Telstra' were subtracted, giving a figure for each financial year.

Template 7 – Quality of Services

Table 7.1 – Reliability

VARIABLE(S)
Table 7.1.1 – Reliability (Inclusive of MEDs) Table 7.1.2 – Reliability (Exclusive of MEDs)

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- System wide SAIFI and SAIDI is by connected kVA for years 2006 - 2010 due to the limitations in Aurora's customer data prior to 2010.
- System wide SAIFI and SAIDI is based on customer data for 2011-2013.
- Note that this deviates from the methodology for applied for Aurora's Annual Reporting RIN.

2	Explain the source of the information to support the variable

Spatial data warehouse:

- Sdw.linked_nmi_feeder

Distribution Business custom asset reporting database (SAM reporting), the following schemas were used:

- Sam_report.wasp_outage
- Sam_report.all_xfmr
- Sam_report.wasp_outage_asset

WASP:

- Wasp_net_stage.outage

- Benchmarking RIN Table 5.2.2 (customer numbers).

3	Explain the methodology applied to provide the required information (inc. any assumptions)

- Outage data extracted from data sources using sql query.
- Exclusions were applied at the query level (in accordance with the chapter 9 definitions).
- MEDs applied to data using MEDs threshold from 2013 Reporting RIN and same methodology.
- System SAIFI and SAIDI calculated using kVA and customers connected (as per Benchmarking RIN Table 5.2.2).
- Pivot tables generated for SAIFI and SAIDI by kVA and customers for template input variables.

Table 7.2 – Energy not supplied

VARIABLE(S)
DQS0201 - Energy Not Supplied (planned) DQS0202 - Energy Not Supplied (unplanned)

1	Demonstrate how the information provided is consistent with the requirements of the RIN
• Energy not supplied due to customer interruptions calculated using average customer demand derived from feeder maximum demand and estimated load factor divided by the number of customers on the feeder, exclusive of excluded outages as defined in chapter 9.	
2	**Explain the source of the information to support the variable**
Spatial data warehouse: • Sdw.linked_nmi_feeder Distribution Business custom asset reporting database (SAM reporting), the following schemas were used: • Sam_report.wasp_outage • Sam_report.all_xfmr • Sam_report.wasp_outage_asset WASP: • Wasp_net_stage.outage • OSI PI Historian • Aurora load forecasts – provided by Network Planning from the Distribution Business. • Benchmarking RIN Table 5.2.2 (customer numbers by location on the network).	

3	Explain the methodology applied to provide the required information (inc. any assumptions)

- All data extracted into temporary working book.

Average Customer Demand

- Feeder demands for last 8 years extracted from PI Historian by Network Planning Team into working book (“Demand A” worksheet).
- Substation power factors from the Aurora load forecast data (supplied by Network Planning Team) into working book (“PF from Load Forecast”) and attributed against feeders (“Feeder Power Factors”).
- Where power factors were not available, proxies were used as advised by Network Planning Team (e.g. used Sorell PF for Richmond zone substation).
- Customer numbers were extracted using same query used for benchmarking RIN table 5.2.2 grouped by feeder. Data extracted into working book (“Customer_Num” worksheet, columns O - Z).
- A limitation with this method is that customers are attributed to feeders using the current network configuration.
- Customer numbers were extracted again using the customer_count attribute against the asset_history.hv_feeder_config table as additional validation against customer numbers by NMI to account for changes in feeder configurations. Data extracted into (“Customer_Num” worksheet, columns AB - AM).
- Final customer numbers were calculated by either taking the customer numbers from the customer number query or the hv_feeder table where there were significant changes to the feeder reconfiguration or the customer number query returned 0.
- Demand was converted into MW in working book (“Demand MW” worksheet) by multiplying the demand by the PF for the feeder by the line to line voltage of the feeder (and the square root of 3 for 3 phase system).
- Average customer demand was calculated in working book (“Average Customer Demand” worksheet) by dividing the demand in MW calculated in the previous step by the number of customers on the feeder for that given year.
- Additional rows were manually added to all required data sets to address feeder number changes (e.g. Kermandie, and unusual feeder configurations e.g. North Hobart).

Energy Not Supplied

- Outage data extracted from data sources using sql query.
- Exclusions were applied at the query level as per the definitions in chapter 9.
- Data saved into working book (“Outage Data” worksheet).
- System SAIFI and SAIDI calculated using kVA and customers connected (as per benchmarking RIN Table 5.2.2).
- No MEDs calculated (as exclusions in chapter 9 do not stipulate MEDs).
- Energy not supplied calculated by multiplying average customer demand on the affected feeder by the customer duration in hours.
- Not all data was available so a check was done to determine what percentage error was in the data to determine if quantity of data errors were acceptable (“Error check” worksheet). A high percentage of errors in earlier years was anticipated due to lack of customer connectivity but rates at more recent years were deemed as acceptable.
- Energy not supplied was sanitised for pivoting by replacing any error fields with 0.
- The count of customers interrupted is sometimes greater than the count of customers on a feeder as it is the total count of customers on all feeders affected by an outage.
- The segment ref is simply a feeder reference - when an outage affects multiple feeders, a single outage record is used to record all affected feeders (switching steps), hence why there is a larger customer count than that on the feeder.

- To compensate for this, when the number of customers interrupted was greater than the number of customers on a feeder, the average energy not supplied for the outage is calculated by multiplying the sanitised energy not supplied by the number of customers on the feeder and dividing by the total number of customers affected by the outage.
- Pivot of data generated providing total energy not supplied for planned and unplanned outages, with exclusions applied as per chapter 9 of instructions and definitions.

Notes

- The count of customers is as the current system configuration.
- These customers may no longer be on the same feeder as they were when the outage occurred or customers may no longer exist in the system against that asset.

Table 7.3 – System losses

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- System losses are calculated as the proportion of energy that is lost in distribution from the transmission network to Aurora Energy customers.
- The electricity imported is the total electricity inflow into Aurora Energy's distribution network (including from embedded generation) minus the total electricity outflow into the networks of the adjacent connected distribution network service providers.
- The electricity delivered is the amount of electricity transported out of Aurora Energy's network to customers as metered at the customer's connection.

2	Explain the source of the information to support the variable

Electricity imported is sourced from:

- DOPED0304 - Energy received from TNSP and other DNSPs not included in the above categories; plus
- Table 5.1.3 Energy - received into DNSP system from embedded generation by time of receipt.

Electricity delivered is sourced from:

- DOPED01 - Total energy delivered.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

The system loss percentage is calculated in accordance with equation 2 of the instructions and definitions:

- (electricity imported – electricity delivered) / electricity imported x 100.

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

The system loss calculation utilises the data from:

  - DOPED0304 (Energy received from TNSP and other DNSPs not included in the above categories),
  - Table 5.1.3 (Energy received into DNSP system from embedded generation by time of receipt); and
  - DOPED01 (Total energy delivered).
- As these variables are estimated for 2006 and 2007, the resulting calculation of the system loss percentage for 2006 and 2007 are also classified as estimates.

Table 7.4 – Capacity utilisation

1	Demonstrate how the information provided is consistent with the requirements of the RIN
• The capacity utilisation measure is the capacity of the zone substation transformers that are utilised each year.	
2	Explain the source of the information to support the variable
• The maximum demand data is extracted from the Aurora load forecasting studies, which includes the required historical maximum demands. • The zone substation capacity is extracted from Aurora systems.	
3	Explain the methodology applied to provide the required information (inc. any assumptions)
• The capacity utilisation variable is calculated as the non-coincident summated raw system annual maximum demand (MVA measure at zone substation level) (DOPSD0201) divided by the total zone substation transformer capacity (DPA0604).	

Template 8 – Operating Environment

Table 8.1 – Density factors

VARIABLE(S)
DOEF0101 - Customer density DOEF0102 - Energy density DOEF0103 - Demand density

1	Demonstrate how the information provided is consistent with the requirements of the RIN
2	Explain the source of the information to support the variable
3	Explain the methodology applied to provide the required information (inc. any assumptions)

DOEF0101 - Customer density

- Total customer numbers (DOPCN02) / route line length (DOEF0301).

DOEF0102 - Energy density

- Total energy delivered (DOPED01) / total customers (DOPCN02).

DOEF0103 - Demand density

- Non-coincident summated raw system annual maximum demand (DOPSD0201) / total customer numbers (DOPCN02).

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

DOEF0101 - Customer density

DOEF0102 - Energy density

DOEF0103 - Demand density

- Variables that utilise the distribution customer numbers from variable DOPCN02 are classed as estimated for the years prior to 2011.
- Refer to the basis of preparation for table 5.2.1/5.2.2 for the underlying estimation basis.

Table 8.2 – Terrain factors

BLACKED-OUT TERRAIN FACTOR VARIABLES
The following orange variable terrain factors for 2009 – 2012 have been blacked-out in accordance with the instructions and definitions: • DOEF0202 - Urban and CBD vegetation maintenance spans. • DOEF0203 - Rural vegetation maintenance spans. • DOEF0204 - Total vegetation maintenance spans. • DOEF0208 - Average number of trees per urban and CBD vegetation maintenance span. • DOEF0209 - Average number of trees per rural vegetation maintenance span. • DOEF0210 - Average number of defects per urban and CBD vegetation maintenance span. • DOEF0211 - Average number of defects per rural vegetation maintenance span. • DOEF0214 - Bushfire risk. Aurora has not historically measured the information in accordance with the variable, and considers it: • Unnecessarily burdensome to estimate the variables; and • Illogical for Aurora to enter '0'.

VARIABLE(S)
DOEF0202 - Urban and CBD vegetation maintenance spans DOEF0203 - Rural vegetation maintenance spans DOEF0204 - Total vegetation maintenance spans

1	Demonstrate how the information provided is consistent with the requirements of the RIN
• The count of vegetation maintenance spans captures only maintenance spans that are the responsibility of Aurora, where Aurora's vegetation contractors undertook active vegetation management (in accordance with definition of active vegetation management practices provided in the instructions & definitions).	
2	Explain the source of the information to support the variable
• The source for determining the number of vegetation maintenance spans was to extract data for 2012/13 from the vegetation contractor timesheets, held in Aurora document management system.	
3	**FOR ESTIMATES ONLY** (where actual information cannot be provided)
Why was it not possible to use actual information?	
• While the information extracted from the vegetation contractor timesheets is actual information, the manual nature of the data extraction and manipulation has lead Aurora to classify the vegetation span variables as estimated data. • Aurora could not certify that the population of contractor timesheets extracted is 100% complete.	
The basis for the estimate	
Estimation approach and assumptions The work details listed below, extracted from the vegetation contractor timesheets, were entered into a database by data and feeder number: • Work date. • Crew/timesheet number. • Feeder number. • Number of spans cut. • Number trees trimmed and cut by size. • Quantity of scrub cleared. • Based on the number of vegetation maintenance spans cut, Aurora was able to determine the number of vegetation maintenance spans (from the data entered on the timesheets). • This was achieved through summing spans cut by feeder classifications, e.g. urban and rural, to derive the total number of maintenance spans for urban and rural. **Reasons why the estimate is the best estimate** • The data contained on the vegetation contractor timesheets is the most reliable source of data available to Aurora for 2013.	

VARIABLE(S)
DOEF0205 – Total number of spans

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- Total HV and LV spans in Aurora's distribution network.
- The total number of spans in Aurora's network irrespective of whether they are vegetation management spans. This does not include service line spans.

2	Explain the source of the information to support the variable

- Spatial data warehouse.

3	Explain the methodology applied to provide the required information (inc. any assumptions)

- Aurora created a span model of the distribution network for vegetation management purposes in late-2013.
- The total span count for 2012/13 was extracted from this data set.
- Spans were limited to those owned by Aurora, through only counting spans that exist between two Aurora owned poles.

4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

- The span data set was only created in late-2013.

The basis for the estimate

Estimation approach

- To determine the 'total number of spans' for 2006 - 2012, the growth factor from estimated line length (DOEF0301) was applied.

Estimation assumptions

- There is a strong correlation between line length (DOEF0301) and total number of spans.

Reasons why the estimate is the best estimate

- The estimate is based on current actual span data.
- Using poles as a proxy for spans results in slightly larger totals.

VARIABLE(S)
DOEF0206 - Average urban and CBD vegetation maintenance span cycle DOEF0207 - Average rural vegetation maintenance span cycle

1	Demonstrate how the information provided is consistent with the requirements of the RIN
	• Relates to the actual cycle achieved for the feeders where close out / sign off data is available. • It is assumed that all spans within the feeder have been attended.
2	Explain the source of the information to support the variable
	• The source for determining the number of maintenance span cycle was to extract data feeder sign off sheets held in Aurora document management system, and previous information collected and held in a spreadsheet which had been collected from monthly reports provided by Network Services Team.
3	Explain the methodology applied to provide the required information (inc. any assumptions)
	The details listed below were extracted into a database: • Feeder number. • Cut type. • Last cut date (completion date for feeder). • Source for Information (sign off sheets or monthly report). • From the last cut date for a feeder, Aurora was able to calculate the period of time in days since the feeder was last cut. • This was then used to calculate and average cycle in years for a feeder classification (i.e. rural/urban), and deemed to be related at a span level.
4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)
	Why was it not possible to use actual information?
	• For historical records (prior to and including 2012), the data is not available in any form that is suitable for this analysis.
	The basis for the estimate
	Estimation approach • For determining previous year’s maintenance cycles, an estimate of the cycles is proposed. **Estimation assumptions** • Aurora has focussed primarily on the quality of cut to specification for spans in the last 3 years, and it has been assessed that there is no conclusive data available to indicate cycle times have materially changed for this period, and back to 2009. • The cycle time for both metrics therefore has been estimated at the 2013 figures for DEOF0206 and DEOF0207. **Reasons why the estimate is the best estimate** • There is no conclusive data available to indicate cycle times have materially changed for this period, and back to 2009.

VARIABLE(S)
DOEF0208 - Average number of trees per urban and CBD vegetation maintenance span DOEF0209 - Average number of trees per rural vegetation maintenance span

1	Demonstrate how the information provided is consistent with the requirements of the RIN
• Aurora has applied a methodology in accordance with the instructions and definitions by using a recognised and modelled vegetation data set overlaid to the network span model using spatial analysis.	
2	Explain the source of the information to support the variable
• The data was sourced from DPIPWE – namely TasVeg, which provided the vegetation communities. • The network data was Aurora's span data – created in 2013 and stored within the GIS (spatial data warehouse) • The tree density data was provided to the consultants engaged to undertake the analysis to provide tree density for each vegetation type. • From this, each span within each feeder was assigned a tree density, and then for each feeder type, an average was determined.	
3	**FOR ESTIMATES ONLY** (where actual information cannot be provided)
The basis for the estimate	
Estimation approach and assumptions • For the vegetation modelling, Aurora has utilised most consistent Tasmanian state-wide vegetation data being TasVeg - provided by the Tasmanian Department of Primary Industries, Parks, Water and Environment (DPIPWE). • This is a comprehensive digital map of Tasmania's vegetation depicting the extent of more than 150 vegetation communities. • The most practical option for deriving an estimate of trees per power line span was to determine a typical tree density for each TasVeg vegetation type. • Each span for each feeder had a tree density assigned. • The average tree density was determined for each span, and then determined for each feeder category. **Reasons why the estimate is the best estimate** • The estimation approach adopted by Aurora utilises the most consistent Tasmanian vegetation data, and is the most practical option available to Aurora.	

VARIABLE(S)
DOEF0210 - Average number of defects per urban and CBD vegetation maintenance span DOEF0211 - Average number of defects per rural vegetation maintenance span

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- The variables provide the average number of trees within Aurora's vegetation management maintenance spans where active vegetation management is required.

2	Explain the source of the information to support the variable

- The source for determining the number of maintenance defects per span was an extract of data for 2012/13 from vegetation contractor timesheets, held in Aurora document management system.

3	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

- While the information extracted from the vegetation contractor timesheets is actual information, the manual nature of the data extraction and manipulation has lead Aurora to classify the vegetation span variables as estimated data.
- Aurora could not certify that the population of contractor timesheets extracted is 100% complete.

The basis for the estimate

Estimation approach and assumptions

The work details below were extracted into a database by feeder number and date:

- Work date.
- Crew/timesheet number.
- Feeder number.
- Number of spans cut.
- Number trees trimmed and cut by size.
- Quantity of scrub cleared.

From the number of trees trimmed and cut by size, along with quantity of scrub cleared, Aurora were able to summarise and determine the number of defects per maintenance span, by:

- Summing number of trees trimmed and cut by feeder classification.
- Calculating a number of defects from quantity of scrub cleared figure by feeder classification.
- Dividing the sum of above by total number of maintenance spans giving average defect per span for feeder classification.

To determine the number of defects relating to the m^2 of scrub cleared the following methodology was used:

- If the quantity of scrub cleared (m^2) was greater than the number of maintenance spans worked on for the day, it was then deemed that there was one defect related to scrub clearing per span.

- For example:

Maintenance spans	Scrub cleared m^2	Quantity of defects
5	100	5

- If the quantity scrub cleared (m^2) was less than the number of maintenance spans worked on for the day, it was then deemed that all the scrub cleared was for only one span hence there was only one defect for the day.
- For example:

Maintenance spans	Scrub cleared m^2	Quantity of defects
5	2	1

Reasons why the estimate is the best estimate

- The data contained on the vegetation contractor timesheets is the most reliable source of data available to Aurora for 2013.

VARIABLE(S)
DOEF0212 – Tropical Proportion

1	Demonstrate how the information provided is consistent with the requirements of the RIN
• Aurora has applied the definition provided for tropical proportions in the instructions and definitions.	
2	Explain the source of the information to support the variable
• Aurora has sourced hot humid summer and warm humid summer regions from the BOM climatic zones map – http://www.bom.gov.au/iwk/climate_zones/map_1.shtml	
3	Explain the methodology applied to provide the required information (inc. any assumptions)
• Aurora's area of responsibility is the mainland of Tasmania and Bruny Island – all of which are within the Temperate Zone. • This zero actual value has been back-cast across prior years.	

VARIABLE(S)
DOEF0213 – Standard vehicle access

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- The standard vehicle access variable is the distribution route line length that does not have standard vehicle access.

2	Explain the source of the information to support the variable

- Spatial data warehouse.
- Department of Infrastructure, Energy and Roads (DIER) transport data.

3	Explain the methodology applied to provide the required information (inc. any assumptions)
4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

a. Why was it not possible to use actual information?

- Aurora is unable to determine the exact access arrangements for all sites indicated.
- There can be seasonal variation (e.g. rain), or land practices (e.g. irrigation/cropping) that do not allow access for normal 2WD vehicles for 100% of the year.
- Additionally, Aurora does not have spatial records for all access tracks.

b. The basis for the estimate

Estimation approach

- GeoMedia was used to undertake a spatial query to retrieve HV and LV conductor and cable segments from the SDW that were outside a 25m buffer of a known road (as recorded by DIER transport data set).
- Analysed the data sets to confirm whether they were valid and appropriate.
- HV cable and LV cable and conductor were excluded as these assets are generally installed in built-up areas where, although the asset may be located outside of a 25m buffer of a known road, they are still accessible by a 2WD vehicle.
- Returned the lengths of the HV conductor segments as the length of the inaccessible network.

Estimation assumptions

- Assumed that spatial modelling of conductors, cables and roads is correct.

Why the estimate is the best estimate

- This is the best methodology that Aurora could apply to provide this variable based on the current information available and the resource constraints.

VARIABLE(S)
DOEF0214 – Bushfire risk

1	Demonstrate how the information provided is consistent with the requirements of the RIN
• Bushfire risk has been determined based upon the number of maintenance spans located in the bushfire loss consequence areas. • The bushfire loss consequence areas were developed as part of Aurora's 2012 Bushfire Mitigation Strategy, where Aurora engaged leading expert Kevin Tolhurst of Melbourne University and David Taylor of Parks and Wildlife to utilise the industry accepted Phoenix Rapid-fire modelling tool to determine areas of fire loss consequence. • This methodology has been utilised by other DNSPs following the VBRC.	
2	Explain the source of the information to support the variable
The feeders within the high bushfire loss consequence areas were identified from the data collected from the vegetation contractor timesheets, these feeders are numbers: • 13045, 30603, 30604, 30608, 35011, 39571, 40002, 41516, 41517, 45002, 45003, 48190.	
3	Explain the methodology applied to provide the required information (inc. any assumptions)
• The number of maintenance spans were totalled for the feeders identified within the high bushfire loss consequence areas.	

Table 8.3 – Service area factors

VARIABLE(S)
Table 8.2 – Terrain factors DOEF0201 – Rural proportion **Table 8.3 – Service area factors** DOEF0301 – Line length

1	Demonstrate how the information provided is consistent with the requirements of the RIN

- Total network route length of Aurora owned network where the length of each span is only considered once.
- Rural proportion is the distribution line route length classified as short rural or long rural / total network route length.

2	Explain the source of the information to support the variable

- Spatial data warehouse.
- AER feeder classifications.

3	Explain the methodology applied to provide the required information (inc. any assumptions)
4	**FOR ESTIMATES ONLY** (where actual information cannot be provided)

Why was it not possible to use actual information?

- Aurora does not have an overhead and underground HV and LV span model – therefore could not calculate the actual route length based on network data.

The basis for the estimate

Estimation approach

- Used Geomedia to create spatial buffers of 5m around Aurora owned overhead and underground circuits from the SDW and merge these buffers where they overlapped (e.g. circuits running in parallel).
- Geomedia cannot calculate a centreline for these buffers but can calculate the total perimeter in metres so the network route length in km were estimated by:
    - ((total sum of perimeter lengths) – (count of number of buffers x 10)) /2 / 1000).
- A correction factor of count of buffers x10 and division by 2 was applied to compensate for the buffering.
- Discovered that route length for overhead LV was greater than circuit length for overhead LV so DPA0101 was used instead - this was determined to be an accurate reflection of the overhead LV network where there are minimal parallel circuits.
- Overhead and underground LV conductors were spatially attributed to a feeder using Geomedia by buffering the circuits and returning the feeder number of the transformer that that the circuits touched.
- This allowed for categorisation of the circuits into feeder types - circuits that returned ‘#N/A’, ‘Not applicable’ or ‘subtransmission’ were apportioned across urban and rural feeder categories.

- Actual overhead and underground HV circuit lengths by feeder category were extracted from the SDW. Because these values are total circuit length instead of route length, they were split into percentage network composition and then this percentage was applied to the estimated route length figures from Geomedia to return estimated network route length by feeder category.
- DOEF0301 (line length) is the sum of these estimated Geomedia route lengths.
- DOEF0201 (rural proportion) is the sum of estimated rural route lengths / total estimated route length.

Estimation assumptions

- The correction factor applied in the estimated route line lengths is appropriate.
- Network feeder composition based on total circuits is an appropriate proxy for route length.

Reasons why the estimate is the best estimate

- This methodology was applied using a smaller buffer size of 1m against actual circuit lengths and the results were found to be within 2%.

Table 8.4 – Weather stations

VARIABLE(S)
DOEF04001 – DOEF04459 Weather Stations

1	Demonstrate how the information provided is consistent with the requirements of the RIN
• Weather station data has been extracted from a listing of the active Bureau of Meteorology (BOM) weather stations in Tasmania.	
2	Explain the source of the information to support the variable
• A listing of all Australian weather stations recorded by the BOM has been downloaded from the BOM website. • Postcodes for Tasmanian towns have been downloaded from the Australia Post website. • A listing of the weather stations used as a component of the weather correction process has been derived from Aurora's load forecasting models.	
3	Explain the methodology applied to provide the required information (inc. any assumptions)

• The BOM weather station listing has been refined to:
    o Include only those weather stations for Tasmania;
    o Remove those stations that have been decommissioned by BOM; and
    o Remove those stations that are outside Aurora's service area.
• The nearest locality (city, suburb, town, place) to the weather stations within the amended listing has been added.
• The postcode (where available) for each locality has been added to the listing. It should be noted that some places (although within the Aurora service area) are not populated and do not therefore have a postcode.
• Those weather stations that are used in Aurora's load forecasting process have been assigned a materiality of "Yes". All other weather stations have been assigned a materiality of "No".	