AER Reset RIN

Powercor Australia Ltd

Basis of Preparation documents

Year ended 31 December 2014

Table of Contents

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AER RESET RIN – HISTORICAL DATA ONLY

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name	**2.4 Augex Model**
Table name: TABLE 2.4.1 - AUGEX MODEL INPUTS - ASSET STATUS - SUBTRANSMISSION LINES	
BOP ID	RRPAL 2.4BOP1

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:
Appendix E - 7.2 Regulatory template 2.4.1 instructions:

(a) Complete the regulatory template by:

i. inserting a row for each subtransmission line on [DNSP name]'s network; and

ii. inputting the required details.

(b) Each row should represent data for an individual circuit.

(c) Insert additional rows as required.

(d) For each subtransmission line, input maximum demand weather corrected at 50 per cent probability of exceedance. If [DNSP name] does not have maximum demand weather corrected at 50 per cent probability of exceedance, input raw adjusted maximum demand, noting such instances in the basis of preparation document(s).

i. The historical maximum demand should reflect the demand for planning purposes, and exclude abnormal operating conditions.

ii. Forecast maximum demand growth rate must be the most realistic expectation of demand at the time of responding to the regulatory information notice, which may or may not be the forecast maximum demand used in developing proposed capital or operating expenditure.

iii. The forecast maximum demand growth rate should reflect the approach typically used for planning purposes.

(e)	In the basis of preparation document(s), explain how the maximum demand data reported in the regulatory template was prepared. Where relevant, this explanation should include: i. How the values reported relate to the maximum demand measures that would be used for normal planning purposes. ii. Whether the values reported are based upon measured values and, if so, where the measurement point is and how abnormal operating conditions were addressed. iii. Whether the historical values reported are based on estimated (rather than actual measured) demand, and, if so, the basis of the estimation process and how the values were validated. iv. How the forecast growth rate was determined. v. The relationship of the values provided to raw unadjusted maximum demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year.
(f)	In the basis of preparation document(s), explain how the asset rating values reported in the regulatory template were determined. Where relevant, this explanation should include: i. The basis of the calculation of the ratings reported, including asset data measured and assumptions made. ii. How the ratings reported for the same assets may be used in augmentation planning and/or the operation of the distribution network. (A) If alternative ratings are used in augmentation planning and/or the operation of the distribution network, explain and define these alternative ratings.

Please provide a Response in this box:

The regulatory template 2.4.1 contains asset status information of Powercor's subtransmission lines asset class. Powercor has provided the historic values of line length, maximum demand and asset ratings for both the 2014 and 2010 calendar years, and the annual demand growth rate forecast between 2014 and 2020.

The historical maximum demands and annual demand growth rate forecasts are weather corrected at 50 per cent probability of exceedance and use N-1 conditions for their basis, as these are the typical values Powercor uses for planning purposes.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL[1] data green; and ESTIMATED[2]/derived data red

[1] Information presented in response to the Notice whose presentation is *materially* dependent on information recorded in Powercor's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice.

'Accounting records' include trial balances, the general ledger, subsidiary accounting ledgers, journal entries and documentation to support journal entries. Actual financial information may include accounting estimates, such as accruals and provisions, and any adjustments made to the accounting records to populate Powercor's regulatory accounts and responses to the Notice. 'Records used in the normal course of business', for the purposes of non-financial information, includes asset registers, geographical information systems, outage analysis systems, and so on.

(Delete any years that are not applicable.)

Area supplied by line, Maximum demand (MVA - 2010), Maximum Demand (MW - 2010), Maximum demand growth rate:

2010	2014

Line ID, Voltage, Originating/Terminating Substation, Route line length (km), Maximum Demand (MVA – 2014), Maximum Demand (MW – 2014), Thermal rating/N-1 Emergency rating.

2010	2014

Note: There exist some minor estimation for Maximum Demand MVA and MW (2014) whilst the vast majority of the data is considered actual. See Section D for further documentation.

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:

Data Type	Source
Line ID	GIS
Area supplied by line	GIS, 2014 Load Forecasts Register
Voltage	GIS
Originating/Terminating Substation	GIS
Route line length (km):	GIS, Circuit Data Sheets
Maximum demand (MVA):	PSSE, 2014 Load Forecasts Register, 2010 Load Forecasts Register
Maximum Demand (MW):	TrendSCADA, 2014 Load Forecasts Register, 2010 Load Forecasts Register
Thermal rating/N-1 Emergency rating:	Circuit Data Sheets, 2010 Distribution System Planning Report (DSPR)
Maximum demand growth rate:	2014 Load Forecasts Register

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2009	N/A
2010	**Line ID:** *Methodology* Each subtransmission line is assigned a unique identifier. This is consistently referred to in all of Powercor's network systems such as asset management, OMS, GIS and related work order scheduling processes. The line ID is created at the time of capital project delivery and, at the subtransmission voltage level, it 'appears' and is recognised in Powercor's systems at its commissioning. Any changes to an existing subtransmission

[2] Historical information presented in response to the *notice* whose presentation is not materially dependent on information recorded in Powercor's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the *notice* is contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the response to the *notice*.

Year	Methodology & Assumptions
	line, due to network reconfiguration or major projects, may result in the creation of a new asset identity reference. This information is provided by Powercor's subtransmission planning group and was extracted after the end of the 2014 year to show the network as of 31 December 2014. There may be a small number of subtransmission lines that may not have existed in previous years. Similarly, there may be a small number of subtransmission lines that are planned for decommissioning in the future. The information in this column represents the actual ID and its reporting does not involve any element of estimation or manual data processing. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Area supplied by line:** *Methodology* This shows as either CBD, Urban, Rural Short or Rural Long areas. There are no CBD designated subtransmission lines in Powercor's network, although all other areas are represented. These designations are referred from and defined in the annual reliability metric reporting. The designation of each subtransmission line was determined by reference to the designation of the terminating zone substation supplied by that subtransmission line, which was in turn determined by the designation of the majority of HV feeders emanating from the zone substations. In the case of a looped subtransmission line arrangement, the terminating zone substation was determined by assessing the power flow. The classification of the subtransmission lines into various areas are therefore refreshed annually at the start of the reliability reporting year (i.e. new financial year), ultimately these are based on the HV feeder classifications. Any new subtransmission lines that come online in the interim are allocated a preliminary categorisation based on the downstream zone substation, HV feeders, review of the customers and area they supply. Any major reconfiguration of the network or major project that changes the subtransmission line characteristics may or may not warrant reclassification of that line during the financial year. Every subtransmission line is classified as one of either type at any given point in time for the purposes of reliability performance reporting. This information is provided by Powercor's subtransmission planning group. This information was extracted after the end of the 2014 year to show the network as of 31 December 2014. The information in this column is mostly actuals based on the explanations provided above; however estimates are also present in some instances involving elements of subjective judgement and organisation knowledge. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. *Assumptions* A snapshot of the network was taken and used to determine the terminating zone substations of a subtransmission line. It is assumed that power always flows in the direction from the snapshot. **Voltage:** *Methodology* Information on the voltage level at which the subtransmission line assets are operated comes from the network schematic diagram, GIS and OMS. Network assets designed and built for a particular voltage level are always operated at that voltage level and are not changed. This information is provided by Powercor's subtransmission planning group. This information was extracted after the end of the 2014 year to show the status as of 31 December 2014. The information in this column is actuals and its reporting does not

Year	Methodology & Assumptions
	involve any estimation or manual data processing. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Originating/Terminating Substation:** *Methodology* This is defined as the terminal or zone substation at the origin of the line, and the zone substation at the terminus. The identity of the two ends of the subtransmission line asset comes from the network schematic diagram and GIS. This information is provided by Powercor's subtransmission planning group. This information was extracted after the end of the 2010 year to show the status as of 31 December 2010. The information in this column is actuals and its reporting does not involve element of estimation or manual data processing. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Route line length (km):** *Methodology* The information on the length of each subtransmission line is extracted from Powercor's network systems such as asset management or asset register and GIS. Circuit Data Sheets for each subtransmission line are available which include the route line length. Any changes to the existing subtransmission line due to network reconfiguration or major projects results in the revision of this data. This information is provided by Powercor's subtransmission planning group and was extracted after the end of the 2014 year to show the status as of 30 June 2010 for the 2010 column. The information in this column is actuals and its reporting does not involve any element of estimation, although it does require manual data processing from the circuit data sheets. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. The following subtransmission lines were commissioned after 2010 and hence there is no 2010 data, WETS-HTH, RCTS-MDA #2, TGTS-NRB, NRB-OWF, NRB-HTN, WETS-RVL, WETS-WMN, SBY-GSB #1, SBY-GSB #2, GSB-WND #1 and GSB-WND #2. **Maximum demand (MVA):** *Methodology* This is defined as the 50% PoE (probability of exceedance) weather corrected peak demand of each subtransmission line over the 2010 period. This information is derived from network simulation using Powercor's PSSE network model. The measured 50% PoE peak zone substation demand (from the 2010 Load Forecasts Register) is used as the basis of these simulations, and power flow in the subtransmission lines are simulated under N-1 contingency scenario. The maximum simulated flow in each subtransmission line in these simulations is used as the maximum demand. The 50% PoE peak zone substations demand is calculated using a PoE calculator. This calculator was improved and updated in 2014 to provide a more accurate 50 PoE representation. As a result, the 50% PoE numbers in 2014 are much lower than the actuals (compared to 2010 where an older version of the calculator was used). This results in a larger difference in the 50% PoE numbers between 2010 and 2014 based on a smaller difference in the raw actuals between 2010 and 2014. These results are then reflected in the N-1 subtransmission line maximum demand.

Year	Methodology & Assumptions
	Some values are estimations as the extraction program used to formulate the subtransmission line maximum demand from the PSSE network model was created to operate with Powercor's 2014 model and does not operate fully with the older 2010 PSSE network model. In cases where the 2010 model did not return a value for network loops the 2014 PSSE network model was used to generate an estimate. The underlying processes, procedures, or business practices used in simulation and reporting are documented, well understood and followed by the responsible staff members. The data derived this way represent the same values that are typically used by Powercor for planning purposes. The subtransmission line ATS-BLTS does not have any maximum demand data as it is a tie line between two terminal stations and is normally open. **Maximum demand (MW):** *Methodology* This is defined as the real power flow component of the 50% PoE weather corrected peak demand of each subtransmission line over the 2010 period. This information is derived using the 2014 power factor and the apparent power flow component of the 2010 50% PoE weather corrected peak demand of each subtransmission line. The Power Factor of a Zone Substation in 2014 is pulled from TrendSCADA meter reading software and is used to calculate the MW of each subtransmission line for that Zone Substation in both 2010 and 2014. 2010 information is estimated as it is assumed that the power factor of each transmission line has not changed between 2010 and 2014. The power factors for T-off BATS-BMH to BGL and BLTS-TYA were estimated using the respective zone substation (BGL and TYA) power factors. **Thermal rating/N-1 Emergency rating:** *Methodology* This is defined as the thermal rating of each line, and the maximum rating under N-1 conditions on the line respectively. In the current version of the dataset Powercor reports the operational rating (equivalent to the N-1 rating). This is the rating used by Powercor for planning purposes. This information is extracted from Powercor's Distribution System Planning Report (DSPR). The numbers in the DSPR come from the Circuit Data Sheets. The capacity rating for new assets is entered in the system at its commissioning and is based on design, manufacturers' specification, network configuration, power system studies etc. Any changes to the existing subtransmission line due to major projects such as re-conductoring results in the revision of this data. This information is provided by Powercor's subtransmission planning group and was extracted after the end of the 2014 year to show the status as of 31 December 2010 for the 2010 columns. The information in this column is actuals and its reporting does not involve an element of estimation. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Average per annum growth rate of line maximum demand:** *Methodology* This is defined as the growth rate of the forecast 50% PoE (probability of exceedance) weather corrected peak demand of each subtransmission line over the 2014 to 2020 period.

Year	Methodology & Assumptions
	The maximum demand forecast growth rate is derived by network simulation using Powercor's PSSE network model. The forecast peak zone substation demand (from the 2014 Load Forecasts Register) between the 2014 to 2020 period is used as the basis of these simulations, and power flow in the subtransmission lines are simulated under an N-1 contingency scenario. The maximum simulated flow in each subtransmission line for each year in the 2014 to 2020 period in these simulations is used to formulate the growth rate. The underlying processes, procedures, or business practices used in simulation and reporting are documented, well understood and followed by the responsible staff members. The data derived this way represent the same values that are typically used by Powercor for planning purposes.
2011	N/A
2012	N/A
2013	N/A
2014	**Line ID:** *<u>Methodology</u>* Same as 2010. **Area supplied by line:** *<u>Methodology</u>* Same as 2010 **Voltage:** *<u>Methodology</u>* Same as 2010 **Originating/Terminating Substation:** *<u>Methodology</u>* Same as 2010 **Route line length (km):** *<u>Methodology</u>* Same as 2010 except for below; The subtransmission lines TGTS-HTN #2, SBY-WND #1 and SBY-WND #2 were decommissioned after 2010 and hence do not have any 2014 data. **Maximum demand (MVA):** *<u>Methodology</u>* This is defined as the 50% PoE (probability of exceedance) weather corrected peak demand of each subtransmission line over the 2014 period. This information is derived from network simulation using Powercor's PSSE network model. The measured 50% PoE peak zone substation demand (from the 2014 Load Forecasts Register) is used as the basis of these simulations, and power flow in the subtransmission lines are simulated under N-1 contingency scenario. The maximum simulated flow in each subtransmission line in these simulations is used as the maximum demand. The underlying processes, procedures, or business practices used in simulation and reporting are documented, well understood and followed by the responsible staff members. The data derived this way represents the same values that are typically used by Powercor for planning purposes. The 50% PoE peak zone substations demand is calculated using a PoE calculator. This calculator was improved and updated in 2014 to provide a more accurate 50% PoE representation. As a result, the 50% PoE numbers in 2014 are much lower than the actuals (compared to 2010 where an older version of the calculator was used). This results in a larger difference in the 50% PoE numbers between 2010 and 2014 based on a smaller difference in the raw actuals between 2010 and 2014. These results are then reflected in the N-1 subtransmission line maximum demand.

Year	Methodology & Assumptions
	The subtransmission line ATS-BLTS does not have any maximum demand data as it is a tie line between two terminal stations and is normally open. The subtransmission line tee-off from BATS-BAS #2 to BGF has been estimated as the BGF MVA load. **Maximum demand (MW):** *Methodology* This is defined as the real power flow component of the 50% PoE (probability of exceedance) weather corrected peak demand of each subtransmission line over the 2014 period. This information is derived using the power factor and the apparent power flow component of the 50% PoE (probability of exceedance) weather corrected peak demand of each subtransmission line. The Power Factor of a Zone Substation in 2014 is pulled from TrendSCADA meter reading software and is used to calculate the MW of each subtransmission line. The power factors for T-off BATS-BMH to BGL and BLTS-TYA were estimated using the respective zone substation (BGL and TYA) power factors. The power factor at NRB-OWF was estimated by using the power factor at the time of the OWF maximum demand. The subtransmission line tee-off from BATS-BAS #2 to BGF has been estimated as the BGF MW load. **Thermal rating/N-1 Emergency rating:** *Methodology* This is defined as the thermal rating of each line, and the maximum rating under N-1 conditions on the line respectively. In the current version of the dataset Powercor reports the operational rating (equivalent to the N-1 rating). This is the rating used by Powercor for planning purposes. This information is extracted from Powercor's asset management system or asset register (Circuit Data Sheets). The capacity rating for new assets is entered in the system at its commissioning and is based on design, manufacturers' specification, network configuration, power system studies etc. Any changes to the existing subtransmission line due to major projects such as re-conductoring results in the revision of this data. This information is provided by Powercor's subtransmission planning group and was extracted after the end of the 2014 year to show the status as of 31 December 2014 for the 2014 columns. Conductor ratings may have changed between 2010 and 2014 due to an update by the Powercor Technical Standards group of the overhead conductor thermal ratings. The information in this column is actuals and its reporting does not involve element of estimation but does require manual data processing from the circuit data sheets. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Average per annum growth rate of line maximum demand:** *Methodology* Same as 2010.

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2009	N/A
2010	**Area supplied by line:** To determine the area supplied by the line, the terminating zone substation is used. In looped subtransmission line circuits, it is possible for the terminating substation to alternate between the zone substations connected to the subtransmission line as power flow is not always in the one direction. A snapshot of the network is used to determine the terminating zone substation of each subtransmission line, which is a form of actual data but could also be considered as an estimate as there is the potential from the snapshot for the direction of power flow to change. **Maximum demand (MVA):** The extraction program used to gather the 50% PoE (probability of exceedance) weather corrected peak demand of each subtransmission line over the 2010 period was originally created to operate with the 2014 model and does not operate fully with the older 2010 PSSE network model. As redeveloping the extraction program would take significant time and effort the 2014 PSSE network model was used to generate an estimate. **Maximum demand (MW):** To determine the maximum demand in MW of the 50% PoE (probability of exceedance) weather corrected peak demand of each subtransmission line over the 2010 period, the power factor of each line is required. Powercor does not have the power factor for the 2010 period. The Power Factor of a Zone Substation in 2014 is pulled from TrendSCADA meter reading software and is used to calculate the MW of each subtransmission line for that Zone Substation in both 2010 and 2014. 2010 information is estimated as it is assumed that the power factor of each transmission line has not changed between 2010 and 2014 **Average per annum growth rate of line maximum demand:** The growth rate by its very nature is a forecast and therefore an estimate.
2011	N/A
2012	N/A
2013	N/A
2014	**Area supplied by line:** Same as 2010 **Maximum demand (MVA):** No maximum demand data is available for the subtransmission line tee-off from BATS-BAS #2 to BGF. The extraction program also did not take BGF into account. Therefore, the BGF load was added to the BATS-BAS #1 and #2 lines to give a better estimate of the maximum demand. **Maximum demand (MW):** No power factor data is available for T-off BATS-BMH to BGL, BLTS-TYA and NRB-OWF. No maximum demand data is available for the subtransmission line tee-off from BATS-BAS #2 to BGF. **Average per annum growth rate of line maximum demand** Same as 2010

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2009	N/A
2010	**Area supplied by line:** Powercor does not internally classify subtransmission lines by the Urban, Rural Short or Rural Long types. Only HV feeders are classed in such a manner. To provide the best estimate the subtransmission lines were based on the HV feeder data by using the terminating zone substation. It is assumed that the power flows in the same direction as the snapshot of the network taken. **Maximum demand (MVA):** The 50% PoE (probability of exceedance) weather corrected peak demand of each subtransmission line over the 2010 period was provided using the 2014 PSSE network model, which extracts correctly the peak demand. Subtransmission lines that have changed since 2010 were estimated using an individual load flow analysis. Radial lines which needed to be estimated were done by using the zone substation MVA figure with losses added to it. All loops which needed to be estimated were done so by using PSSE. Powercor found this to be the most accurate estimate available. **Maximum demand (MW):** To determine the maximum demand in MW of the 50% PoE (probability of exceedance) weather corrected peak demand of each subtransmission line over the 2010 period, the power factor of each line from the 2014 dataset was used, which is an actual value. **Average per annum growth rate of line maximum demand:** The maximum demand forecast growth rate is derived by network simulation using Powercor's PSSE network model. The forecast peak zone substation demand (from the 2014 Load Forecasts Register) between the 2014 to 2020 period is used as the basis of these simulations, and power flow in the subtransmission lines are simulated under an N-1 contingency scenario. Powercor considers this the best available forecast method.
2011	N/A
2012	N/A
2013	N/A
2014	**Area supplied by line:** Same as 2010. **Maximum demand (MVA):** The subtransmission line tee-off from BATS-BAS #2 to BGF has been estimated as the BGF MVA load as BGF is the only supply point on the line. The BATS-BAS #1 and #2 subtransmission lines have been estimated as the extraction program results (does not include BGF load) summated with the BGF MVA load. **Maximum demand (MW):** The power factors for T-off BATS-BMH to BGL and BLTS-TYA were estimated using the respective zone substation (BGL and TYA) power factors. The power factor at NRB-OWF was estimated by using the power factor at the time of the OWF maximum demand. The subtransmission line tee-off from BATS-BAS #2 to BGF has been estimated as the BGF MW load as BGF is the only supply point on the line. **Average per annum growth rate of line maximum demand:** Same as 2010

AER RESET RIN – HISTORICAL DATA ONLY

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 2.4 Augex Model	
Table name: TABLE 2.4.2 - AUGEX MODEL INPUTS - ASSET STATUS - HIGH VOLTAGE FEEDERS	
BOP ID	RRPAL2.4BOP2

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:
APPENDIX E: PRINCIPLES AND REQUIREMENTS

7.3 Regulatory template 2.4.2 instructions:

(a) Complete the regulatory template by:

i. inserting a row for each high voltage feeder on [DNSP name]'s network; and

ii. inputting the required details.

(b) Each row should represent data for an individual circuit.

i. Each high voltage feeder must be identified by a unique ID number.

(c) The high voltage feeder rating should be based upon the main trunk segment exiting the substation.

(d) The maximum demand should be the demand measured at the feeder exit from the associated substation.

(e) For each high voltage feeder, input maximum demand weather corrected at 50 per cent probability of exceedance. If Powercor does not have maximum demand weather corrected at 50 per cent probability of exceedance, input raw adjusted maximum demand, noting such instances in the basis of preparation document(s).

i. The historical maximum demand should reflect the demand for planning purposes, and exclude abnormal operating conditions.

ii. Forecast maximum demand growth rate must be the most realistic expectation of demand at the time of responding to the regulatory information notice, which may or may not be the forecast maximum demand used in developing proposed capital or operating expenditure.

iii. The forecast maximum demand growth rate should reflect the approach typically used for planning purposes.

(f) *Insert additional rows as required.*

(g) *In the basis of preparation document(s), explain how the maximum demand data reported in the regulatory template was prepared. Where relevant, this explanation should include:*

i. How the values reported relate to the maximum demand measures that would be used for normal planning purposes.

ii. Whether the values reported are based upon measured values and, if so, where the measurement point is and how abnormal operating conditions were addressed.

iii. Whether the historical values reported are based on estimated (rather than actual measured) demand, and, if so, the basis of the estimation process and how the values were validated.

iv. How the forecast growth rate was determined.

v. The relationship of the values provided to raw unadjusted maximum demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year.

(h) *In a separate document, explain how the asset rating values reported in the regulatory template were determined. Where relevant, this explanation should include:*

i. The basis of the calculation of the ratings reported, including asset data measured and assumptions made.

ii. How the ratings reported for the same assets may be used in augmentation planning and/or the operation of the distribution network.

(A) *If alternative ratings are used in augmentation planning and/or the operation of the distribution network, explain and define these alternative ratings.*

Please provide a Response in this box:

The information provided in table 2.4.2 is consistent with the requirements of the reset RIN notice.

Route line lengths are the measured total of the route line length per feeder (either underground and overhead or both).

The maximum demands are the measured seasonal maximum demand per feeder (summer or winter).

The feeder rating is the maximum thermal and operational rating of the feeder conductor (either underground or overhead) installed on that feeder.

The measured maximum demand complies with the definition in chapter 10 of the National Electricity Rules, version 60. Information provided is consistent with the requirements of the Reset RIN Notice.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

Average per Annum Growth Rate in Annual High Voltage Feeder Maximum Demand

Forecast

All Other Variables/Descriptors – except as documented below

2010	2014

Maximum Demand (MW)

2010	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:

HIGH VOLTAGE FEEDER	UNIT		Source
Line ID	n/a		GIS
Area Supplied by Line	n/a		GIS, 2014 Load Forecasts Register
Voltage	KV		GIS
Originating Substation	Name		GIS
ROUTE LINE LENGTH	KM		Geographical Information System (GIS)
MAXIMUM DEMAND	MVA		TrendSCADA software
	MW		TrendSCADA software
RATING	MVA	THERMAL	Powercor Technical Standards Policies
		OPERATIONAL	Based on Powercor's network planning policy and guidelines, per feeder category
AVERAGE PER ANNUM GROWTH RATE IN ANNUAL HIGH VOLTAGE FEEDER MAXIMUM DEMAND	%		Extracted from the Powercor Load Forecasts

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2009	N/A
2010	**Line ID:** *Methodology* Each HV Feeder is assigned a unique identifier. This is consistently referred to in all of Powercor's network systems such as asset management, OMS, GIS and related work order scheduling processes. The ID is created at the time of capital project delivery and, at the HV Feeder voltage level, it 'appears' and is recognised in Powercor's systems at its commissioning. Any changes to an existing HV Feeder, due to network reconfiguration or major projects, may result in the creation of a new asset identity reference. The information in this column represents the actual ID and its reporting does not involve any

Year	Methodology & Assumptions
	element of estimation or manual data processing **Area supplied by line:** *Methodology* This shows as either CBD, Urban, Rural Short or Rural Long areas. These designations are referred from and defined in the annual reliability metric reporting. The designation of each HV Feeder was determined by reference to the designation of the originating zone substation connected to the HV Feeder. This is achieved based on review of the customers and area that the HV feeders supply. This information was extracted from GIS. The information in this column are all actuals based on the explanations provided above. **Voltage:** *Methodology* Information on the voltage level at which the HV Feeders assets are operated comes from the network schematic diagram, GIS and OMS. Network assets designed and built for a particular voltage level are always operated at that voltage level and are not changed. The information in this column is actuals and its reporting does not involve any estimation or manual data processing. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Originating Substation:** *Methodology* This is defined as the terminal or zone substation at the origin of the line, and the zone substation at the terminus. The identity of the two ends of the HV Feeder asset comes from the network schematic diagram and GIS. The information in this column are actuals and its reporting does not involve element of estimation or manual data processing. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Route line length (km):** This presents the total length of the HV feeder. The lengths provided in this version of the dataset refer to the sum of each circuit on the feeder, i.e. a double circuit between two points would have a longer length than a single circuit feeder between the same two points. It is noted that the line lengths for 2010 came from Powercor's previous RIN submissions. This information is extracted from Powercor's network systems such as asset management or asset register and GIS. The line length detail for new assets is entered into the system at its commissioning. Any changes to the existing HV Feeder line due to network reconfiguration or major projects results in the revision of this data. **Maximum demand (MVA):** The 50% PoE weather corrected peak demand of each HV feeder over the period requested by the AER. Powercor does not typically weather correct HV feeder maximum demand observations due to the potential difference in temperature between ends of the feeder, so the non-weather corrected data is reported. These data represent the same values that are typically used by Powercor for normal planning purposes. All data are measured at the feeder exit points of the zone substation, with abnormal conditions removed from the maximum demand data by field measurement devices when available, and expert judgement by network planners when not. This information is extracted from Powercor's maximum demand historical and forecasting

Year	Methodology & Assumptions
	database. The information in the column are mostly calculated, based on measured current flow, nominal operating voltage, phase, and power quality. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Maximum demand (MW):** As above, but the real power flow component of the demand which is a component of the MVA calculation above. The Power Factor of a Zone Substation in 2014 is pulled from TrendSCADA meter reading software and is used to calculate the MW of each feeder for that Zone Substation in both 2010 and 2014. This information is estimated as it is assumed that the power factor of each feeder line has not changed between 2010 and 2014. **Thermal rating/ Operating rating:** The thermal rating of each HV feeder and the rating to which the network is run during normal conditions respectively. In the current version of the dataset Powercor reports the cyclic rating of each feeder as thermal rating, while planning rating of the feeders are used as the operational rating. This information is sourced from GIS or construction drawings, and reflects the normal cyclic rating of each feeder. The Operational rating is based on Powercor's network planning policy and guidelines. The operational rating is the rating used by Powercor for planning purposes. This information is extracted from Powercor's asset management system or asset register. The capacity rating for new assets is entered in the system at its commissioning and is based on design, manufacturers' specification, network configuration, power system studies etc. Any changes to the existing HV feeder due to major projects such as re-conductoring results in the revision of this data. The information in the column are all actuals. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Average per annum growth rate:** A bottom-up and top-down process is used to produce 50% PoE weather corrected zone substation forecasts. This is implemented by producing a bottom up terminal station forecast from HV distribution feeder forecasts and comparing with a top-down terminal station forecast. The bottom-up forecast is then refined until there is acceptable agreement between the terminal station forecasts produced by each method. The top-down terminal station forecasts are econometric forecasts supplied by the Centre for International Economics (CIE)."
2011	N/A
2012	N/A
2013	N/A
2014	**Originating Substation:** Same as 2010 **Voltage:** Same as 2010 **Area supplied by line:** Same as 2010 **Line ID:** Same as 210 **Route line length (km):** Same as 2010 **Maximum demand (MVA):** Same as 2010

Year	Methodology & Assumptions
	Maximum demand (MW): Same as 2010 **Thermal rating/ Operating rating:** The thermal rating of each HV feeder, and the rating to which the network is run during normal conditions respectively. In the current version of the dataset Powercor reports the cyclic rating of each feeder as thermal rating, while planning rating of the feeders are used as the operational rating. This information is sourced from GIS or construction drawings, and reflects the normal cyclic rating of each feeder. Post 2010, the thermal rating of conductors was reviewed based on ambient temperature and wind speed. The thermal conductor ratings were divided into four geographical regions based on Bureau of Meteorology data across Powercor's network. The HV Feeder thermal ratings were revised using the new regional conductor rating. The Operational rating is based on Powercor's network planning policy and guidelines. The operational rating is the rating used by Powercor for planning purposes. This information is extracted from Powercor's asset management system or asset register. The capacity rating for new assets is entered in the system at its commissioning and is based on design, manufacturers' specification, network configuration, power system studies etc. Any changes to the existing HV feeder due to major projects such as re-conductoring results in the revision of this data. The information in the column are all actuals. The underlying processes, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Average per annum growth rate:** Same as 2010

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2009	N/A
2010	**Maximum Demand (MW):** The Power Factor for Zone Substations in 2010 was unavailable. **Average per annum growth rate:** The forecast maximum demand growth rate is an estimate of the underlying growth rate of individual feeders. An estimate is required as it is a forecast value.
2011	N/A
2012	N/A
2013	N/A
2014	**Average per annum growth rate:** Same as 2010

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2009	N/A

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2010	**Maximum Demand (MW):** The Power Factor of a Zone Substation in 2014 was used to calculate the MW of each feeder for that Zone Substation in 2010. The Historical Power Factor for each zone substation over the last few years remain relatively the same or similar hence was deemed sufficient to use the 2014 power factor instead of 2010. This was the best available estimate. **Average per annum growth rate:** The estimate is based on historical feeder maximum demands with abnormal conditions removed and allowances made for localised growth supplied by the HV feeder network. The basis of the estimate is typical of the approach used for planning purposes during the bottom up spatial reconciliation process. The process is well understood and followed by the responsible staff members and is the best estimate available.
2011	N/A
2012	N/A
2013	N/A
2014	**Average per annum growth rate:** Same as 2010

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 2.4 Augex Model	
Table name: TABLE 2.4.3 - AUGEX MODEL INPUTS - ASSET STATUS – SUBTRANSMISSION SUBSTATIONS, SUBTRANSMISSION SWITCHING STATIONS AND ZONE SUBSTATIONS	
BOP ID	RRPAL2.4BOP3

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:
Appendix E - 7.4 Regulatory template 2.4.3 instructions:

(a) Complete the regulatory template by:

i. inserting a row for each subtransmission substation, subtransmission switching station and zone substation on [DNSP name]'s network; and

ii. inputting the required details.

(b) Each row should represent data for an individual substation.

(c) Insert additional rows as required.

(d) For each subtransmission substation, subtransmission switching station and zone substation, input maximum demand weather corrected 50 per cent probability of exceedance. If [DNSP name] does not have maximum demand weather corrected at 50 per cent probability of exceedance, input raw adjusted maximum demand, noting such instances in the basis of preparation document(s).

i. The historical maximum demand should reflect the demand for planning purposes, and exclude abnormal operating conditions.

ii. Forecast maximum demand growth rate must be the most realistic expectation of demand at the time of responding to the regulatory information notice, which may or may not be the forecast maximum demand used in developing proposed capital or operating expenditure.

iii. The forecast maximum demand growth rate should reflect the approach typically used for planning purposes.

(e) In the basis of preparation document(s), explain how the maximum demand data reported in the regulatory template was prepared. Where relevant, this explanation should include:

i. How the values reported relate to the maximum demand measures that would be used for normal planning purposes.

ii. Whether the values reported are based upon measured values and, if so, where the measurement point is and how abnormal operating conditions were addressed.

iii. Whether the historical values reported are based on estimated (rather than actual measured) demand, and, if so, the basis of the estimation process and how the values were validated.

iv. How the forecast growth rate was determined.

v. The relationship of the values provided to raw unadjusted maximum demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year.

(f) In the basis of preparation document(s), explain how the asset rating values reported in the regulatory template were determined. Where relevant, this explanation should include:

i. The basis of the calculation of the ratings reported, including asset data measured and assumptions made.

ii. How the ratings reported for the same assets may be used in augmentation planning and/or the operation of the distribution network.

(A) If alternative ratings are used in augmentation planning and/or the operation of the distribution network, explain and define these alternative ratings.

Please provide a Response in this box:

The regulatory template 2.4.3 contains asset status information of Powercor's zone substation asset class. The subtransmission substation and subtransmission switching station asset classes were not reported on as the Powercor network does contain any types of these stations.

Powercor has provided the historic values of the number of transformers, maximum demand and transformer and substation asset ratings for both the 2014 and 2010 calendar years, and the zone substation annual demand growth rate forecast between 2014 and 2020.

The historical maximum demands and annual demand growth rate forecasts are weather corrected at 50 per cent probability of exceedance and are the typical values Powercor uses for planning purposes.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

Substation Ratings – Transformer Normal Cyclic Total, Maximum Demand (MW - 2010), Maximum demand growth rate

2010	2014

Substation ID, Substation Type, Primary type of area supplied, Substation Primary / Secondary Voltage, Number of Transformers, Maximum demand (MVA):, Maximum demand (MW - 2014):,Substation Ratings – Transformer Nameplate Total (ONAN), Substation Ratings – Transformer Nameplate Total (in service), Substation Ratings – Substation Normal Cyclic, Substation Ratings – N-1 Emergency

2010	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:

Data Type	Source
Substation ID	GIS
Substation Type	GIS
Primary type of area supplied	2014 Load Forecast Register, Annual Reliability Reporting
Substation Primary/ Secondary Voltage	GIS
Number of Transformers	2010 & 2015 Zone Substations Cyclic Ratings Table
Maximum Demand (MVA)	2010 & 2014 Load Forecast Register
Maximum Demand (MW)	TrendSCADA, 2010 & 2014 Load Forecast Register
Substation Ratings – Transformer Nameplate Total (ONAN)	2010 & 2015 Zone Substations Cyclic Ratings Table
Substation Ratings – Transformer Nameplate Total (in service)	2010 & 2015 Zone Substations Cyclic Ratings Table
Substation Ratings – Transformer Normal Cyclic Total	2010 & 2015 Zone Substations Cyclic Ratings Table
Substation Ratings – Substation normal Cyclic	2010 & 2015 Zone Substations Cyclic Ratings Table
Substation Ratings – N-1 Emergency	2010 & 2015 Zone Substations Cyclic Ratings Table
Maximum demand growth rate	2014 Load Forecast Register

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2009	N/A
2010	**Substation ID:** *Methodology* Unique asset identifier for each zone substation. The zone substation network boundary is defined by all substation infrastructure between subtransmission circuit breakers and HV feeder circuit breakers. Each zone substation is assigned a unique identifier. This is consistently referred in all of Powercor's network systems such as asset management, OMS, GIS and related work order scheduling processes. The substation ID is created at the time of capital project delivery and,

Year	Methodology & Assumptions
	at zone substation level, it ‘appears’ and is recognised in the system at its commissioning. This information is provided by Powercor’s distribution planning group and was extracted after the end of the 2014 year to show the status as of 31 December 2014. There may be few zone substations that may not have existed in previous years. Similarly, there may be few zone substations that are planned for decommissioning in the future. The information in this column is actuals and its reporting does not involve element of estimation or manual data processing. The underlying process, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Substation Type:** *Methodology* Can be one of subtransmission substation, subtransmission switching station, or zone substation. All the assets in Powercor’s network are zone substations as per extractions from GIS. **Primary type of area supplied:** *Methodology* Either CBD, Urban, Rural Short or Rural Long areas. There are no CBD designated zone substations in Powercor’s network, though all other areas are represented. These designations are referred from and defined in the annual reliability metric reporting. This designation is determined by the equivalent designations of the HV feeders emanating from the zone substation that carry the majority of the load. The classification of the substations are therefore refreshed annually at the start of the reliability reporting year (i.e. new financial year) ultimately based on the HV feeder classifications. Any new substations that come online in the interim are allocated a preliminary categorisation based on the downstream HV feeders, review of the customers and area they supply. Any major reconfiguration of the network or major project that changes the emanating HV feeder characteristics may or may not warrant reclassification of the substation during the financial year. Every substation is classified as one of the either types at any given point in time for the reliability performance reporting. This information is provided by Powercor’s distribution planning group. This information was extracted after the end of the 2014 year to show the status as of 31 December 2014. The information in this column is actual values based on the explanations provided above. The underlying process, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Substation Primary / Secondary Voltage:** *Methodology* Powercor’s zone substation step down 66kV to either the 11kV or 22kV level. The information of the substation voltage levels at which the transformation occurs comes from the network schematic diagram, asset register, GIS and OMS. Network assets designed and built for a particular voltage level are always usually operated at that voltage level and are not changed. This information is provided by Powercor’s distribution planning group. This information was extracted after the end of the 2014 year to show the status as of 31 December 2014. The information in this column is actuals and its reporting does not involve element of estimation or manual data processing. The underlying process, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Number of Transformers:**

Year	Methodology & Assumptions
	Methodology The total number of in service transformers at zone substation. This information comes from the network schematic diagram, asset register, annual planning and regulatory reports (2010 Zone Substations Cyclic Ratings Table). The state of the transformers energisation is also confirmed from these systems in order to exclude de-energised, system spare and de-commissioned assets. This information is provided by Powercor's distribution planning group. This information was extracted to show the status as of 30 June 2010 for the 2010 column. The information in the 2010 column is actuals and its reporting does not involve element of estimation or manual data processing. The underlying process, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. Data for the zone substation GSB is not included for any of the 2010 data fields as it was not constructed until after the year 2010. **Maximum demand (MVA):** *Methodology* The 50% PoE weather corrected peak demand of each zone substation over the period requested by the AER for the 2010 period. It is noted that this data is weather corrected using Powercor PoE calculator to 50% PoE based on temperature measurement taken at the nearest Bureau of Meteorology weather station to the zone substation. The probability of exceedance is then calculated by applying Monte Carlo simulation on this data. This process is used to produce both 50% PoE and 10% PoE values and is based on the date the raw unadjusted maximum demand occurred and the weather temperature data. This data represents the same values that are typically used by Powercor for normal planning purposes. The Powercor PoE calculator is in accordance with best practice methodologies for regulatory weather correction. The 50% PoE calculator was improved and updated in 2014 to provide a more accurate 50 PoE representation. As a result, the 50% PoE numbers in 2014 are much lower than the actuals (compared to 2010 where an older version of the calculator was used). This results in a larger difference in the 50% PoE numbers between 2010 and 2014 based on a smaller difference in the raw actuals between 2010 and 2014. This information is extracted from Powercor's maximum demand historical and forecasting database (2010 Load Forecast Register). The reported historical raw data are measured values by energy meters in the respective substation. The underlying process, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. The zone substation LVN11 supplies only one customer and is treated as a customer substation for planning purposes, a raw maximum demand has been inputted in place of the 50% PoE (probability of exceedance) weather corrected maximum demand. The zone substation KRT was operating with a split 22kV bus in 2010 and no 50% PoE (probability of exceedance) weather corrected maximum demand was recorded. The summation of the two KRT buses has been used to formulate a raw maximum demand for the zone substation. **Maximum demand (MW):** *Methodology* As above, but the real power flow component of the demand which is a component of the MVA calculation above. The Power Factor of a Zone Substation in 2014 is pulled from TrendSCADA This information is estimated as it is assumed that the power factor of each Zone Substation has not changed between 2010 and 2014. **Substation Ratings – Transformer Nameplate Total (ONAN):**

Year	Methodology & Assumptions
	Methodology The sum of nameplate total of transformers unforced cooling (i.e. Oil Natural Air Natural) rating. This information is extracted from Powercor's asset management system or asset register (2010 Zone Substations Cyclic Ratings Table). The capacity rating for new assets is entered in the system at its commissioning and is based on design and manufacturers' specification. This information is provided by Powercor's distribution planning group and was extracted to show the status as of 30 June 2010 for the 2010 columns. The information in the 2010 column is actuals and its reporting does not involve element of estimation or manual data processing. The underlying process, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Substation Ratings – Transformer Nameplate Total (in service):** *Methodology* The sum of nameplate total of transformers with cooling mechanism. This information is extracted from Powercor's asset management system or asset register (2010 Zone Substations Cyclic Ratings Table). The capacity rating along with the additional cooling capacity for new assets is entered in the system at its commissioning and is based on design and manufacturers' specification. This information is provided by Powercor's distribution planning group and was extracted to show the status as of 30 June 2010 for the 2010 columns. The information in the 2010 column is actuals and its reporting does not involve element of estimation or manual data processing. The underlying process, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Substation Ratings – Transformer Normal Cyclic Total:** *Methodology* The sum of the cyclic ratings of each transformer, in cases where a zone substation contains similar transformers. At stations where the transformers are mismatched, the way the transformers share load has been factored into the transformer normal cyclic rating total. The cyclic total rating is derived by adding the individual cyclic rating of each in service transformer when the transformers have the same or similar nameplate ratings. For cases where the in service transformers have completely different ratings, an assessment of actual loads was used to determine how the transformers shared load, as typically they will not share load equally. The transformer normal cyclic rating total was then calculated using the cyclic rating of the transformer that is the limiting factor, by determining the loads on the other transformers at that level of load (MVA of the limiting factor transformer). The individual transformer cyclic ratings are derived using a software package called "Transformer Load Simulator" (TLS), which is based on Australian Standard AS2374.7 – 1997. It requires inputs of transformer details, load profiles and ambient temperature profiles to calculate the cyclic rating. Furthermore, Powercor applies limits to certain temperature and rate of life values to generate a cyclic rating that ensures the transformer's lifespan is economically viable. This information is provided by Powercor's distribution planning group and was extracted to show the status as of 30 June 2010 for the 2010 columns. The information in the 2010 column is mostly actuals with some element of estimation in case of a few assets. This is due to the varying nature of how some transformer share load, for zone substations with mismatched transformers. The underlying process, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members.

Year	Methodology & Assumptions
	Assumptions For zone substations with mismatched transformers, that they always share load the same way as when assessed by distribution planning staff. **Substation Ratings – Substation Normal Cyclic:** *Methodology* This data refers to the sum of nameplate total of transformers with cooling mechanism, as defined above, as a substitute for normal cyclic ratings. The AER definition of substation normal cyclic specifies that this column should refer to the maximum rating that the zone substation could sustain without causing damage, i.e. the cyclic rating of the zone substation if it was being run at its N rating. This definition is used so the AER has a consistent comparison between DNSP's that may run different parts of their network to different standards. Planning and augmentation requirements in the Powercor network are based on the cyclic rating of the station to an N-1 security standard for all substations with more than one transformer, i.e. the constant load the station can handle while providing for the possibility of a transformer failing. The relationship of this rating to the nameplate total is approximately the nameplate total minus the nameplate rating of the largest transformer. Most Powercor raw data are measured relative to this 'N-1 cyclic' rating (e.g. utilisation thresholds), while the RIN Table and the AER Augex Model are populated with the nameplate rating described above. Where necessary, planning parameter data have been adjusted to match the AER Augex Model by applying the ratio of these two ratings. The normal cyclic rating reported is not the maximum cyclic rating the substation can support, as Powercor runs zone substations based on their ability to withstand contingency events. The rating entered in this column of the RIN tables is the same as the nameplate total of all in-service transformers instead. This information is provided by Powercor's distribution planning group and was extracted to show the status as of 30 June 2010 for the 2010 columns. The information in the 2010 column is actuals and its reporting does not involve element of estimation or manual data processing. The underlying process, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible staff members. **Substation Ratings – N-1 Emergency:** *Methodology* This is the rating that the substation could handle for up to 2 hours after an N-1 event at the substation. The individual 2 hour emergency transformer cyclic ratings are used to derive the N-1 emergency substation rating. The individual 2 hour emergency transformer cyclic ratings are calculated using the TLS software and the same inputs as described above in the Transformer Normal Cyclic Total methodology. Different limits are applied for the 2 hour emergency transformer cyclic ratings. This information is extracted from Powercor's asset management system or asset register (2015 Zone Substations Cyclic Ratings Table) and is based on individual transformer ratings and their connection within the respective substation. Any changes to the existing substation transformation capacity due to substation extension projects, as an example, could result in the revision of this data. This information is provided by Powercor's distribution planning group and was extracted to show the status as of 30 June 2010 for the 2010 columns. The information in the 2010 column is actuals and its reporting does not involve element of estimation or manual data processing. The underlying process, procedures, or business practices used in recording, generating, processing and reporting are documented, well understood and followed by the responsible

Year	Methodology & Assumptions
	staff members.
2011	N/A
2012	N/A
2013	N/A
2014	**Substation ID:** *Methodology* Same as 2010 **Substation Type:** *Methodology* Same as 2010 **Primary type of area supplied:** *Methodology* Same as 2010 **Number of Transformers:** *Methodology* Same as 2010 **Maximum demand (MVA):** *Methodology* Same as 2010 **Maximum demand (MW):** *Methodology* Same as 2010 **Substation Ratings – Transformer Nameplate Total (ONAN):** *Methodology* Same as 2010 **Substation Ratings – Transformer Nameplate Total (in service):** *Methodology* Same as 2010 **Substation Ratings – Transformer Normal Cyclic Total:** *Methodology* Same as 2010 **Substation Ratings – Substation Normal Cyclic:** *Methodology* Same as 2010 **Substation Ratings – N-1 Emergency:** *Methodology* Same as 2010 **Maximum demand growth rate:** *Methodology* The average per annum growth rate of the forecast 50% PoE weather corrected peak demand from 2014 to 2020. A bottom-up and top-down process is used to produce 50% PoE weather corrected zone substation forecasts. This is implemented by producing a bottom up terminal station forecast from HV distribution feeder forecasts and comparing with a top-down terminal station forecast.

Year	Methodology & Assumptions
	The bottom-up forecast is then refined until there is acceptable agreement between the terminal station forecasts produced by each method. The top-down terminal station forecasts are econometric forecasts supplied by the Centre for International Economics (CIE). Linear regression is then applied to the 50% PoE weather corrected peak demand zone substation forecasts between the 2014-2020 period to derive the growth rate. This information is provided by Powercor's distribution planning group.

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2009	N/A
2010	**Substation Ratings – Transformer Normal Cyclic Total:** Some zone substations have mismatched transformers that do not share load equally and it is not appropriate to summate the individual transformer cyclic ratings. **Maximum Demand (MW).** The Power Factor for Zone Substations in 2010 was unavailable
2011	N/A
2012	N/A
2013	N/A
2014	**Substation Ratings – Transformer Normal Cyclic Total:** Same as 2010 **Maximum demand growth rate:** The growth rate by its very nature is a forecast and therefore an estimate.

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2009	N/A
2010	**Substation Ratings – Transformer Normal Cyclic Total:** To determine the transformer normal cyclic rating, actual measured loads in each transformer are used to determine how they share load between each other. These values are accurate as they are based on actuals but it is assumed that they will always share load at the same ratio. **Maximum Demand (MW):** The Power Factor of a Zone Substation in 2014 was used for that Zone Substation in 2010. The Historical Power Factor for each zone substation over the last few years remain relatively the same or similar hence was deemed sufficient to use the 2014 power factor instead of 2010. This was the best available estimate.
2011	N/A
2012	N/A
2013	N/A
2014	**Substation Ratings – Transformer Normal Cyclic Total:** Same as 2010 **Maximum demand growth rate:** Sound load forecasting methodologies by Powercor have been used to produce growth rates, as growth rates are estimated figures. These rates have been calculated by applying the best

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
	knowledge available to Powercor.

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 2.4 Augex Model	
Table name: TABLE 2.4.4 - AUGEX MODEL INPUTS - ASSET STATUS – DISTRIBUTION SUBSTATIONS	
BOP ID	RRPAL2.4BOP4

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:
Appendix E - 7.5 Regulatory template 2.4.4 instructions:

(a) Complete the regulatory template by:

i. inserting a row for each distribution substation category; and

ii. inputting the required details.

(b) As it will be difficult to provide data for individual distribution substations, distribution substation categories should be formed that capture sets of distribution substations on [DNSP name]'s network, based upon factors such as:

i. pole-mounted or ground-mounted distribution substations,

ii. distribution substation ratings or

iii. the area types supplied (i.e., CBD, urban, rural).

(c) Each distribution substation category must be identified by a unique ID number.

(d) Insert additional rows as required.

(e) The description provided for each distribution substation category should identify characteristics such as pole-mounted or ground-mounted, range of ratings covered, area types supplied, etc.

(f) Where actual maximum demand is not measured at individual distribution substations within a category, estimate maximum demand and utilisation based on customer types and numbers supplied from the distribution substation.

(g) Input specified information relating to maximum demand weather corrected at 50 per cent probability of exceedance. If [DNSP name] does not have maximum demand weather corrected at 50 per cent probability of exceedance, input specified information relating to raw adjusted maximum demand, noting such instances in the basis of preparation document(s).

i. The historical maximum demand should reflect the demand for planning purposes, and exclude abnormal operating conditions.

ii. Forecast maximum demand growth rate must be the most realistic expectation of demand at the time of responding to the regulatory information notice, which may or may not be the forecast maximum demand used in developing proposed capital or operating expenditure.

iii. The forecast maximum demand growth rate should reflect the approach typically used for planning purposes.

(h) In the basis of preparation document(s), explain how the maximum demand data reported in the regulatory template was prepared. Where relevant, this explanation should include:

i. How the values reported relate to the maximum demand measures that would be used for normal planning purposes.

ii. Whether the values reported are based upon measured values and, if so, where the measurement point is and how abnormal operating conditions were addressed.

iii. Whether the historical values reported are based on estimated (rather than actual measured) demand, and, if so, the basis of the estimation process and how the values were validated.

iv. How the forecast growth rate was determined.

v. The relationship of the values provided to raw unadjusted maximum demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year.

(i) In the basis of preparation document(s), explain how the asset rating values reported in the regulatory template were determined. Where relevant, this explanation should include:

i. The basis of the calculation of the ratings reported, including asset data measured and assumptions made.

ii. How the ratings reported for the same assets may be used in augmentation planning and/or the operation of the distribution network.

(A) If alternative ratings are used in augmentation planning and/or the operation of the distribution network, explain and define these alternative ratings.

Please provide a Response in this box:
Powercor has reported on Distribution Substations using actual maximum demands over the 2010 and 2014 periods. These maximum demands and the asset ratings have been used to create an asset utilisation profile. Growth rates have also been provided for the 2014 to 2020 period but are estimated values, as Powercor does not forecast at the Distribution Substation level for its planning purposes.

Raw actual maximum demands were used to formulate the utilisation factors, as Powercor does not weather correct at the Distribution Substation level for its planning purposes.

Powercor has used the following Distribution Substation categories to represent the Distribution Substation dataset:

i) SWER Substation – Domestic
ii) SWER Substation – Commercial
iii) SWER Substation – Industrial
iv) SWER Substation – Agricultural
v) SWER Substation – Others
vi) Single/Three Phase Substation – Domestic
vii) Single/Three Phase Substation – Commercial
viii) Single/Three Phase Substation – Industrial
ix) Single/Three Phase Substation – Agricultural
x) Single/Three Phase Substation – Others

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substations category (%):
Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substations category (MVA)

2010	2014

Description of distribution substation category
Distribution substation category ID

2010	2014

Average per annum growth rate in annual substation maximum demand from 2014 to 2020

Forecast

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:

Data Type	Source
Distribution Substation Category ID	Label / Identifier
Description of Distribution Substation Category	SAP reporting (SAP HANA), GIS
Utilisation Histogram (MVA):	SAP reporting (SAP HANA), GIS
Total MVA:	SAP reporting (SAP HANA), GIS
Maximum demand growth rate:	2014 Load Forecast Register

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.

(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2009	N/A
2010	**Distribution substation category ID:** *Methodology* This is a unique asset identifier for each distribution substation category. The distribution network boundary between asset identifiers is defined by the substations and LV lines between HV Feeder exits and customer metering infrastructure. Every separate row in this Table represents an aggregated distribution capacity within a series of set utilisation ranges **Description of distribution substation category:** *Methodology* Powercor has configured this asset class into two asset categories based transformer types and further into five asset sub-categories based on customer types. Therefore, in total there are ten asset sub-categories in this Table. Powercor has used customer types so that distribution substations are then categorised by the type of load they are supplying, which may provide a greater representation of the differences in utilisation then categorising only by asset type (pole type, ground type, etc.) or asset ratings. The asset types are: i) SWER Substation – Domestic ii) SWER Substation – Commercial iii) SWER Substation – Industrial iv) SWER Substation – Agricultural v) SWER Substation – Others vi) Single/Three Phase Substation – Domestic vii) Single/Three Phase Substation – Commercial viii) Single/Three Phase Substation – Industrial ix) Single/Three Phase Substation – Agricultural x) Single/Three Phase Substation – Others **Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substations category (%):** *Methodology* Aggregates have been created for normal cyclic ratings that were within the utilisation bands 0-20%, 20-30%, 30-40% and so on up to 160-180%. The utilisation of each individual transformer was determined using the 2010 maximum demand and normal cyclic rating. A summation of the normal cyclic ratings for each distribution substation, in each category, for each utilisation band has been displayed in percentage terms. The maximum demand data for the 2010 period is derived from Powercor's GIS system, which in turn originated from Powercor's Market Data Systems (MDS). The MDS system used the energy sales from each individual distribution substation to calculate a maximum demand figure. Due to the energy sales conversion calculation, this data is estimated. In addition, this data is also not weather corrected as it is a significant workload to weather correct these tables and historically Powercor have never used weather corrected values for planning purposes at these lower levels (HV feeders and Distribution Substations).. The normal cyclic ratings are based on the nameplate ratings as specified by the distribution substation equipment manufacturers, as that is the loading a substation can provide each day of its life under normal conditions resulting in a normal rate of wear. Normal conditions are considered as those that do not add undue stress, an accelerated rate of wear or decrease in

Year	Methodology & Assumptions
	the life of an asset. The normal cyclic rating information is extracted from Powercor's GIS system. The capacity rating for new assets is entered into the system at its commissioning and is based on design, and manufacturers' specification. *Assumptions* The energy sales conversion calculation for the 2010 maximum demand may not be accurate in all cases. Distribution substations with an installation date after 1 January 2011 and that have 2010 maximum demand data are assumed to have been replaced with a distribution substation of the same normal cyclic rating. This can occur as GIS reports the installation date when the last distribution substation was installed on the pole. This date does not take into consideration replacements of a distribution substation, so in our system it could say the distribution substation was installed in 2011 but in actual fact there can be a distribution substation at that site from before that date, with replacements in 2011. All duplicate data was removed, as well as substations with abnormal names or locations. Any substations without a 2010 maximum demand were removed. All utilisations over 200% were also removed as it has been assumed the transformer would have failed at such a loading. Utilisations under 0% were also removed as they were seen as unrealistic. **Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substations category (MVA):** *Methodology* Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substation category. Powercor used the GIS system to extract the normal cyclic ratings of each distribution substation. These values are actuals and no estimation was required. Assumption The data that is populated is accurate (according to the system it was extracted from) although what's shown is not the whole data source. It is only a sample of the data and should be treated as such. Powercor's systems have not been setup to accurately measure a 2010 distribution substation MD and a large amount of the data source had to be removed because it could not be accurately interpreted. The process to extract this data involved using two different reports from the GIS system and amalgamating them to get the two data points required at each distribution substation site. Data had to be removed were a match could not occur between the two reports.
2011	N/A
2012	N/A
2013	N/A
2014	**Distribution substation category ID:** *Methodology* Same as 2010 **Description of distribution substation category:** *Methodology* Same as 2010 **Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substations category (%):** *Methodology* Aggregates have been created of the normal cyclic ratings of all individual distribution substations in the distribution substation category that were within the utilisation bands 0-20%, 20-30%, 30-40% and so on up to 160-180%. The utilisation of each individual transformer was determined using the 2014 maximum

Year	Methodology & Assumptions
	demand and normal cyclic rating. A summation of the normal cyclic ratings for each distribution substation, in each category, for each utilisation band has been displayed in percentage terms. The maximum demand data for the 2014 period is derived from Powercor's SAP HANA reporting system, which uses a summation of the customer smart meter loads to calculate the individual distribution substation maximum demands. These values are actuals and no estimation is required. In addition, this data is not weather corrected as it is a significant workload to weather correct these tables and historically Powercor have never used weather corrected values for planning purposes at these lower levels (HV feeders and Distribution Substations). The normal cyclic ratings are based on the nameplate ratings as specified by the distribution substation equipment manufacturers, as that is the loading a substation can provide each day of its life under normal conditions resulting in a normal rate of wear. Normal conditions are considered as those that do not add undue stress, an accelerated rate of wear or decrease in the life of an asset. The normal cyclic rating information is extracted also from Powercor's SAP HANA reporting system, which has replaced the obsolete MDS system. The capacity rating for new assets is entered in the system at its commissioning and is based on design, and manufacturers' specification. A small number of cyclic ratings were deemed to be incorrect and were manually modified to their actual values. A visual identification of the substation was used to determine the actual cyclic rating. *Assumptions* Duplicate data found was removed, as well as substations with abnormal names or locations. Any substations without a 2014 maximum demand were removed. All utilisations over 200% were also removed as it has been assumed the transformer would have failed at such a loading. Utilisations under 0% were also removed as they were seen as unrealistic. **Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substations category (MVA):** *Methodology* Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substation category. Powercor used the SAP HANA reporting system to extract the normal cyclic ratings of each distribution substation. A small number of cyclic ratings were deemed to be incorrect and were manually modified to their actual values, the rest of the information are actuals. A visual identification of the substation was used to determine the actual cyclic rating. **Average per annum growth rate in annual substation maximum demand from 2014 to 2020:** The peak demand forecast growth rate in percentage per annum, for the 2014-2020 period. This information was sourced from the internal 2014 Load Forecast Register determined by network planning and is an overall growth rate applicable for all the distribution substation asset categories. The maximum demand growth for the distribution network is based on the average growth rate of demand of all Powercor HV Feeders, as Powercor does not forecast maximum demands at the Distribution Substation level for planning purposes. The HV feeder forecasts and therefore the forecasts average growth rate of all Powercor HV feeders uses 50% POE weather corrected values.

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2009	N/A
2010	**Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substations category (%):** Powercor's historical systems (MDS) were not designed to record accurate distribution substation maximum demands. Hence, a large portion of the original dataset needed to be removed or interpreted where it was not practical to be included in this reporting requirement. **Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substations category (MVA):** This data can only be considered a sample. C's systems were not setup to accurately measure a 2010 distribution substation MD and a large amount of the data source had to be removed because it could not be accurately interpreted
2011	N/A
2012	N/A
2013	N/A
2014	**Average per annum growth rate in annual substation maximum demand from 2014 to 2020:** Powercor does not forecast maximum demands at the Distribution Substation level for its planning purposes. Also, the growth rate by its very nature is a forecast and therefore an estimate.

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2009	N/A
2010	**Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substations category (%):** In 2010 the Powercor system (MDS) was not set up to accurately record maximum demand levels; The MDS system used the energy sales from each individual distribution substation to calculate a maximum demand figure. Due to the energy sales conversion calculation, this data is estimated to the best of Powercor's abilities or removed where it cannot be. **Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substations category (MVA):** The process to extract this data involved using two different reports from the GIS system and amalgamating them to get the two data points required at each distribution substation site. Data had to be removed were a match could not occur between the two reports
2011	N/A
2012	N/A
2013	N/A
2014	**Average per annum growth rate in annual substation maximum demand from 2014 to 2020:** The maximum demand growth for the distribution network is based on the average growth rate of demand of all Powercor HV Feeders, as this is the lowest level in the distribution network that Powercor forecasts maximum demands for planning purposes. These values are based on 50% POE weather corrected values. Powercor considers this method of forecasting as the best estimate.

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 2.4 Augex Model	
Table name: TABLE 2.4.5 - AUGEX MODEL INPUTS - NETWORK SEGMENT DATA	
BOP ID	RRPAL2.4BOP5

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:
Appendix E - 7.6 Regulatory template 2.4.5 instructions:

(a) Complete the regulatory template by inserting a row for each network segment of [DNSP name]'s distribution network and providing the required details.

(b) [DNSP name] must define the most appropriate network segments.

(c) Individual network segments should be defined to capture differences in the main drivers of augmentation, such as growth in maximum demand, augmentation unit costs, or utilisation thresholds.

(d) In forming individual network segments, it should be considered that this data will be used for the augex model, which is intended to forecast at an aggregate level and not for specific circumstances.

(e) As a general guide, between 15 and 30 individual network segments should be sufficient to model the whole distribution network.

(f) Insert additional rows as required.

(g) In completing the AER segment group details in the regulatory template, select the most appropriate group from the following list:

i. subtransmission lines (ID number: 1)

ii. subtransmission substations and subtransmission switching stations (ID number: 2)

iii. zone substations (ID number: 3)

iv. high voltage feeders – CBD (ID number: 4)

v. high voltage feeders – urban (ID number: 5)

vi. high voltage feeders - short rural (ID number: 6)

vii. high voltage feeders - long rural (ID number: 7)

viii. distribution substations – CBD, including downstream low voltage network (ID number: 8)

ix. distribution substations – urban, including downstream low voltage network (ID number: 9)

x. distribution substations – short rural, including downstream low voltage network (ID number: 10)

xi. distribution substations – long rural, including downstream low voltage network (ID number: 11)

(h) In the basis of preparation document(s), provide a definition and description of each network segment reported in the regulatory template, including details on:

i. boundaries with other connecting network segments; and

ii. the main reason why the network segment was reported as an individual network segment and not bundled with other network segments.

(i) In the basis of preparation document(s), explain how the unit costs and capacity factors reported in the regulatory template were calculated for each network segment. This must cover the following:

i. The methodology, data sources, and assumptions used to derive the augmentation unit cost or capacity factor.

ii. The relationship of the parameters to actual historical augmentation projects, including the capacity added through these projects and the cost of these projects.

iii. The possibility of double-counting in the estimates (for example, when an individual project may add capacity to multiple network segments), and the process applied to ensure that this is appropriately addressed.

iv. The process applied to verify that the augmentation unit costs and capacity factors reported are a reasonable estimate for the network segment.

(j) In the basis of preparation document(s), explain of how the utilisation thresholds reported in the regulatory template were calculated for each network segment. This must cover the following:

i. The methodology, data sources, and assumptions used to derive the utilisation threshold.

ii. The relationship to internal and/or external planning criteria that define when an augmentation is required.

iii. The relationship to actual historical utilisation at the time that augmentations occurred for that network segment.

iv. Views on the most appropriate probability distribution to simulate the augmentation needs of that network segment.

v. The process applied to verify that the utilisation thresholds are a reasonable estimate of the utilisation limit for the network segments.

Please provide a Response in this box:

Powercor has reported on the values of average unit cost, capacity factor, mean value of utilisation factor and standard deviation of utilisation factor for 10 segments which best represent the Powercor asset base. Values are based on both historical projects and then forecast projects where appropriate.

The individual network segments have been defined to best show the differences in augmentation of the asset type.

The 10 segments reported on are as follows:

i) subtransmission lines with a growth rate less than 0% (<0%)
ii) subtransmission lines with a growth rate between 0% and 2% (0-2%)
iii) subtransmission lines with a growth rate between 2% and 4.5% (2-4.5%)
iv) subtransmission lines with a growth rate greater than 4.5% (>4.5%)
v) HV urban feeders
vi) HV short rural feeders
vii) HV long rural feeders
viii) zone substations - urban
ix) zone substations - rural
x) distribution substations (including downstream LV network)

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

Historical	Forecast

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:

Data Type	Source
Average unit cost of augmentation for the network segment	Historical project information, SAP financial reporting (ZF21 transaction), forecast project data.
Capacity factor for the period	2013 Distribution Annual Planning Report (DAPR), GIS, historical project information.
Mean value of the utilisation threshold for the period	2013 Distribution Annual Planning Report (DAPR), historical project information, Powercor planning policies.
Standard deviation of the utilisation threshold for the period	Historical project information.

Note: The same data was used by Jacobs to determine the Historical and Forecast data in template 2.4.5

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
Historical	Powercor commissioned the consultants Jacobs to determine the historical figures herein. The historical data was taken from a report on the Augex Model for Powercor. Jacobs used a project list provided by Powercor to calculate the Historical data inputs. The project list was created using multiple sources. SAP was the source used to identify projects and also retrieve the financials for each project. GIS was used for project scopes, SAP or other project documentation sources were used to get the conductor/cable distances, asset units and MVA added figures. Jacobs also used the Distribution Annual Planning Report (DAPR) in some calculations. A summary for each category is existent below. Average Unit Cost: This represents the average of historical cost of projects divided by the MVA capacity added of the projects. Capacity Factor: This represents the average of the asset capacities after augmentation divided by the asset capacities before the augmentation. Utilisation Threshold Mean: This represents the average of the utilisations of the assets at the time of augmentation. Utilisation Threshold Standard Deviation: This represents using the historical project utilisation thresholds; a standard deviation formula was applied to develop the standard deviation.
Forecast	Powercor engaged consultant Jacobs, to formulate the inputs required to populate Table 2.4.5. Jacobs used a step-by-step combinatorial approach to determine only a small number of historical and forecast planning parameter sets with logical variable values to produce reasonable modelling outcomes. In order to formulate the planning parameter values in the Reset RIN Table 2.4.5 that forms the input variables in the AER Augex Model, Jacobs analysed a number of recent historical augmentation projects data comprising of actual cost details (excluding overheads), demand levels, asset capacity prior to and after those projects, and the then network configuration. For the forecast planning parameter values, in situations where the characteristics of upcoming network constraints are considerably different from historical project data, Jacobs relied on the upcoming network solutions provided by Powercor. Jacobs compared the augmentation capacity and augmentation cost separately, since the changing of the unit cost does not impact the capacity. A sensitivity analysis was completed to best determine realistic planning parameter values for Reset RIN Table 2.4.5. It should be noted that all forecast figures have been classed as estimates, as per their very nature they are not actual values even though they have been based on actuals where it has been deemed appropriate. **Asset grouping:** ***Subtransmission lines*** *Methodology* The recommended scenario that produced the most reasonable forecasts was when the subtransmission lines asset class is grouped based on their annual maximum demand growth rate forecast only. No distinction is made between urban and rural lines using this configuration or grouping. The low sample of size of data meant that only one figure that is applied to all asset

Year	Methodology & Assumptions
	categories could be produced for the forecast planning parameter variable values. Using other asset categories that weren't based on the growth rate led to results that under-predicting augmentation capacity. This is because there is a weak correlation in the subtransmission line asset class between highly loaded assets and fast-growing assets. There is a clear correlation between subtransmission lines that are more heavily loaded, and lines which are highly utilised. Accounting for this relationship, significantly increases the accuracy of forecasts. ***HV feeders*** <u>*Methodology*</u> The most accurate forecasts are produced when the HV feeders asset class is configured or grouped based on their primary area served only. The primary area served was Urban, Rural Short, or Rural Long categories for all asset items. This configuration or grouping was found to be the main determinant of the forecast planning parameters as creating additional asset sub-categories based on length or growth rate did not increase accuracy. ***Zone substations*** <u>*Methodology*</u> The best results were achieved by configuring or grouping this asset class based on their primary area served. Since there are only a small number of zone substation projects to base the forecast planning parameter variable values on, the number of asset categories has been kept as small as possible and therefore are classified as either Urban or Rural, with no distinction based on Rural Short/Long. No significant differences in forecast planning parameter variable values between Rural Short and Rural Long asset categories were observed. Powercor runs its single transformer zone substations to a different security standard than multiple transformer zone substations, but as none of these zone substations are highly utilised at present, categorising these assets differently does not add any accuracy to the forecasts. ***Distribution substations and downstream LV networks*** <u>*Methodology*</u> The best combinations of forecast planning parameter variable values derived from the available data involved simplifying and averaging variable values across multiple asset categories, so the recommended grouping also aggregates all assets. Jacobs experimented with various ways of assigning forecast planning parameter variable values to the formed asset categories, and have concluded that the most reasonable results involve basing most forecast planning parameter variable values off the average of all historic projects. **Average unit cost of augmentation for the network segment:** ***Subtransmission lines*** <u>*Methodology*</u> The $/MVA unit cost was derived from the Powercor historic project records. A weighted average cost was used as it puts greater emphasis on larger projects, because larger projects influence the mean of the entire dataset more. The weighted average $/MVA unit cost is defined as: $$\frac{\sum Total\ Direct\ Costs\ of\ historic\ augmentation\ projects}{\sum Total\ MVA\ of\ Capacity\ added\ by\ historic\ augmentation\ projects}$$ Due to the limited size of the historic project information, Jacobs was unable to formulate separate $/MVA unit costs for various asset categories in the subtransmission lines asset class, and so the same $/MVA unit cost has been applied for all asset categories. The

Year	Methodology & Assumptions
	costs are based on real $2015 dollars. ***HV feeders*** *<u>Methodology</u>* The $/MVA unit cost was derived from planned and committed HV feeder projects in the Powercor network over the 2016-2020 period. A weighted average cost was used as it puts greater emphasis on larger projects, because larger projects influence the mean of the entire dataset more. This method produces a much lower $/MVA unit cost than the unweighted method, which gives undue emphasis to several small HV Feeder projects with individually very high unit rates. The weighted average $/MVA unit cost is defined as: $$\frac{\sum Total\ Direct\ Costs\ of\ planned\ augmentation\ projects}{\sum Total\ MVA\ of\ Capacity\ added\ by\ planned\ augmentation\ projects}$$ All planned HV feeder projects in the 2016-2020 period were considered in this cost calculation. The HV feeder augmentation cost can be extremely variable, as the true cost of augmentation depends on factors that are not captured completely by the AER Augex Model, such as the proportion of the feeder that requires augmentation. The costs are based on real $2015 dollars. ***Zone substations*** *<u>Methodology</u>* The $/MVA unit cost was derived from planned and committed zone substation projects in the Powercor network over the 2016-2020 period, using the weighted average cost method. A weighted average cost was used as it puts greater emphasis on larger projects, because larger projects influence the mean of the entire dataset more. The weighted average $/MVA unit cost is defined as: $$\frac{\sum Total\ Direct\ Costs\ of\ planned\ augmentation\ projects}{\sum Total\ MVA\ of\ Capacity\ added\ by\ planned\ augmentation\ projects}$$ All planned zone substation projects in the 2016-2020 period were considered in this cost calculation, which can therefore be considered representative of future augmentation requirements. The costs are based on real $2015 dollars. ***Distribution substations and downstream LV networks*** *<u>Methodology</u>* The $/MVA unit cost was derived using the weighted average cost method based on the historic Urban asset category projects. This weighted average $/MVA unit cost is defined as: $$\frac{\sum Total\ Direct\ Costs\ of\ urban\ historic\ augmentation\ projects}{\sum Total\ MVA\ of\ Capacity\ added\ by\ urban\ historic\ augmentation\ projects}$$ This value was derived from historic project records. The weighted average value puts greater emphasis on larger projects, because larger projects influence the mean of the entire dataset more. The $/MVA unit cost is based only on Urban category project and does not consider those designated Rural Short or Rural Long. Rural category projects tended to have much higher costs, and weren't considered representative of the whole category. The historic projects record contains only a subset of all projects. Any average derived from this set of data assumes that the proportion of Urban, Rural Short and Rural Long

Year	Methodology & Assumptions
	asset categories in the Powercor network is the same as in the historic record. This is not a safe assumption because the majority of capacity that makes up the network is designated either Domestic or Commercial. Customers in these categories are assumed to be predominately within Urban areas. The best estimate of $/MVA unit cost should therefore give most weight to urban projects. The costs are based on real $2015 dollars. **Capacity factor for the period:** ***Subtransmission lines*** *Methodology* The Capacity Factor was calculated with reference to Powercor 2013 DAPR. This document contains planned and potential augmentations to the subtransmission network. $Capacity\ Factor = \frac{\sum Total\ MVA\ of\ planned\ subtransmisssion\ line\ projects}{\sum Ratings\ of\ all\ lines\ with\ forecast\ demand\ greater\ than\ N-1\ capacity}$ Planned augmentation projects in the Powercor network involve significant reconfiguration of the network, with some projects involving construction of both subtransmission lines and zone substation assets to address network constraints. To avoid double counting, new subtransmission line capacity increase is used in derivation of that asset class Capacity Factor and new zone substation capacity increase is used in derivation of that asset class Capacity Factor. When calculated in this manner, the subtransmission line asset class Capacity Factor as derived 1.71 which is substantially higher than for historic projects, but reflective of the large amount of new capacity planned in the Powercor network. Although this parameter is not based on historic data, Jacobs considers it to be the most accurate for forecasting purposes, as the projects planned are substantially different than those undertaken in the past. Previous projects were all uprating of overloaded conductors yielding a low Capacity Factor with higher utilisation threshold values. The planned changes involve significant augmentations to the network with projects that address constraints in multiple assets, and consequently a higher Capacity Factor with lower Utilisation Threshold Mean value. ***HV feeders*** *Methodology* The Capacity Factor was calculated by comparing the capacity being added to the Powercor network for each previous augmentation project compared to the ratings of feeders pre-augmentation. $Capacity\ Factor = \frac{\sum Total\ capacity\ of\ augmented\ feeders\ in\ historic\ project\ record}{\sum Rating\ of\ feeders\ prior\ to\ the\ augmentation\ project}$ Powercor's historic HV feeder project record consists of several projects that are feeder upgrades and several that are new feeders. This Capacity Factor was derived by considering only feeders that were uprated and had a clearly defined pre and post augmentation capacity. Sufficient data was available to derive the Capacity Factors for the Urban, Rural Short and Rural Long asset categories. ***Zone substations*** *Methodology* The Capacity Factor was calculated by comparing the capacity being added to the Powercor network for each previous augmentation project compared to the ratings of the zone substation pre-augmentation.

Year	Methodology & Assumptions
	$$Capacity\ Factor = \frac{\sum Total\ MVA\ added\ through\ Historic\ Augmentation\ projects}{\sum Total\ preaugmentation\ MVA\ of\ zone\ substation\ which\ were\ augmented}$$ Ten historic zone substation upgrade projects formed a historic augmentation project record and were used to derive the Capacity Factor. Due to the size of the dataset this has been applied to all asset categories. This Capacity Factor produced comparable forecasts to one derived from the DAPR. ***Distribution substations and downstream LV networks*** *Methodology* The Capacity Factor in the input data set is not based on the historic project records. Deriving this value from the historic data can overestimate the true value because the amount of capacity added to the network and not the post-augmentation rating of the asset should be compared against the capacity of the constrained asset that triggered the augmentation. The sensitivity analysis revealed that combinations of forecast planning parameter variables using Capacity Factors based on the historic set resulted in unexpected forecast costs. Instead, a Capacity Factor of 1 is used in the input data set as it indicates that a constrained distribution transformer is generally augmented by either installing a new and similar asset, or doubling the size of the existing one. *Assumptions* That a constrained distribution transformer is generally augmented by either installing a new and similar asset, or doubling the size of the existing one. **Mean value of the utilisation threshold for the period:** ***Subtransmission lines*** *Methodology* The Utilisation Threshold Mean is derived from the 2013 DAPR. This document contains an assessment of the forecast load on subtransmission lines that are being reviewed for augmentation. The forecast peak loading of all subtransmission lines that have committed augmentation projects planned as a response to network constraints have been averaged, to produce a threshold of 113% of N-1 utilisation. Because Powercor's planned and committed projects involve network reconfigurations, the assets which are effectively augmented are not just those at the highest utilisations, but also include less overloaded assets that may be incidental to the most pressing constraints in the network. A lower utilisation mean reflects the potential for these lines to contribute to the models forecast of augmentation. ***HV feeders*** *Methodology* The Utilisation Threshold Mean is based on historic HV feeder projects. This value is derived by averaging the utilisation of HV feeders at the time of their augmentation. Since both operational and thermal ratings have been provided for this asset class, these Utilisation Thresholds have been adjusted so that they are relative to the thermal rating for each category. This adjustment is performed by multiplying the threshold by the ratio of thermal and operating ratings for each feeder. If the raw threshold mean is M (measured relative to the operational rating), then the derived threshold for feeder x is: $$Derived\ threshold_X = M \times \frac{A_X}{B_x}$$ Where, A_X = The operational rating of the feeder x; and B_X = The thermal rating of the feeder x.

Year	Methodology & Assumptions
	Zone substations *<u>Methodology</u>* The Utilisation Threshold Mean is based on Powercor planning parameters. This threshold is not considered deterministic, but rather as one of several triggers that result in a more detail review of the asset. The threshold derived using this method is 120% of the N-1 rating. As the AER Augex Model is run using utilisations that are relative to the N cyclic capacity (the nameplate total is used as a proxy for this in the Powercor dataset) this value has been adjusted relative to this standard. This adjustment is performed by multiplying the threshold by the ratio of nameplate and N-1 cyclic ratings for each zone substation. If the raw threshold mean is M (measured relative to the N-1 cyclic rating), then the derived threshold for zone substation x is: $$Derived\ threshold_X = M \times \frac{A_X}{B_x}$$ Where A_X = The N-1 cyclic rating of the zone substation x; and B_X = The nameplate rating of the zone substation x. ***Distribution substations and downstream LV networks*** *<u>Methodology</u>* The Utilisation Threshold Mean is based on an average of all historic distribution transformer projects. **Standard deviation of the utilisation threshold for the period:** ***Subtransmission lines*** *<u>Methodology</u>* The standard deviation in the Utilisation Threshold has been derived from the pre-augmentation utilisations of subtransmission lines, in Powercor's historic augmentation project record. This method has been applied in all scenarios. ***HV feeders*** *<u>Methodology</u>* The standard deviation in the Utilisation Threshold has been derived from the various utilisation positions of HV feeders, at pre-augmentation state, in the historic augmentation project record. There is enough data to derive this value for each asset subcategories. However, the Utilisation Threshold Standard Deviation of Urban projects when considered alone is particularly low (~4%), and likely not reflective of true variance. The AER Augex Model under-predicts capacity using this method, as a standard deviation this low results in disproportionate forecast augmentation in the first year of the forecasts. Instead, the Utilisation Threshold Standard Deviation for each asset category is based on the deviation in threshold of projects within all asset categories which is approximately 12%. ***Zone substations*** *<u>Methodology</u>* The standard deviation in the Utilisation Threshold has been derived from the utilisation positions of zone substations, at pre-augmentation state, in the historic augmentation project record. The value from this method has been applied for all asset categories. ***Distribution substations and downstream LV networks*** *<u>Methodology</u>* The deviation in the Utilisation Threshold has been derived from the various utilisations positions of distribution transformer, at pre-augmentation state, in the historic augmentation project record.

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
Historical	N/A all data is actual
Forecast	Note that all forecast values have been classed as estimates, as forecasts are estimates by their very nature.

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
Historical	N/A all data is actual
Forecast	Jacobs used various approaches as a basis for their estimates. Powercor considers the use of Jacobs as the best possible estimate given their third party expertise.

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 2.4 Augex Model	
Table name: TABLE 2.4.6 - CAPEX AND NET CAPACITY ADDED BY SEGMENT GROUP (Total and NSP)	
BOP ID	RRPAL2.4BOP6

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

Appendix E - 7.7 Regulatory template 2.4.6 instructions:

(a) The type of net capacity should match the various types of rating indicated in regulatory templates 2.4.1 to 2.4.4 (on regulatory template 2.4). For example, for zone substations:

i. type 1 reflects the name plate (in service) rating;

ii. type 2 reflects the normal cyclic rating; and

iii. type 3 reflects the N-1 emergency rating.

(b) For the purposes of the regulatory template, 'customer-initiated & capacity-related augmentation' refer to activities for which incurred costs are attributed to at least one of the following AER expenditure categories:

i. New connection - augmentation to subtransmission lines

ii. New connection - augmentation to subtransmission substations and subtransmission switching stations

iii. New connection - augmentation to zone substations

iv. New connection - augmentation to HV CBD feeders

v. New connection - augmentation to HV urban feeders

vi. New connection - augmentation to HV short rural feeders

vii. New connection - augmentation to HV long rural feeders

viii. New connection - augmentation to distribution substations, CBD (including downstream LV network)

ix. New connection - augmentation to distribution substations, urban (including downstream LV network)

x. New connection - augmentation to distribution substations, short rural (including downstream LV network)

xi. New connection - augmentation to distribution substations, long rural (including downstream LV network)

(c) For the purposes of the regulatory template, 'NSP-initiated & capacity-related augmentation' refer to activities for which incurred costs are attributed to at least one of the following AER expenditure categories:

i. NSP-initiated & capacity-related augmentations - subtransmission lines

ii. NSP-initiated & capacity-related augmentations - subtransmission stations

iii. NSP-initiated & capacity-related augmentations - zone substations

iv. NSP-initiated & capacity-related augmentations - HV CBD feeders

v. NSP-initiated & capacity-related augmentations - HV urban feeders

vi. NSP-initiated & capacity-related augmentations - HV short rural feeders

vii. NSP-initiated & capacity-related augmentations - HV long rural feeders

viii. NSP-initiated & capacity-related augmentations - distribution substations, CBD (including downstream LV network)

ix. NSP-initiated & capacity-related augmentations - distribution substations, urban (including downstream LV network)

x. NSP-initiated & capacity-related augmentations distribution substations, short rural (including downstream LV network)

xi. NSP-initiated & capacity-related augmentations - distribution substations, long rural (including downstream LV network)

Please provide a Response in this box:
Powercor has reported on costs incurred by NSP-initiated & capacity-related augmentation for the categories of:

i) subtransmission lines
ii) subtransmission stations
iii) zone substations
iv) HV CBD feeders
v) HV urban feeders
vi) HV short rural feeders
vii) HV long rural feeders
viii) distribution substations, CBD (including downstream LV network)
ix) distribution substations, urban (including downstream LV network)
x) distribution substations, urban (including downstream LV network)

xi) distribution substations, long rural (including downstream LV network)
xii) unmodelled augmentation

The historical incurred cost totals have been split into the 2010-2013 and 2014 groupings.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2010	2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:

Data Type	Source
Subtransmission Lines	SAP reporting (transaction F220), SAP financial reporting, project scope documents
Subtransmission Stations	SAP reporting (transaction F220), SAP financial reporting, project scope documents
Zone Substations	SAP reporting (transaction F220), SAP financial reporting, project scope documents
HV CBD Feeders	SAP reporting (transaction F220), SAP financial reporting, project scope documents
HV Urban Feeders	SAP reporting (transaction F220), SAP financial reporting, project scope documents
HV Short Rural Feeders	SAP reporting (transaction F220), SAP financial reporting, project scope documents
HV Long Rural Feeders	SAP reporting (transaction F220), SAP financial reporting, project scope documents
Distribution Substations, CBD (including downstream LV network)	SAP reporting (transaction F220), SAP financial reporting, project scope documents
Distribution Substations, Urban (including downstream LV network)	SAP reporting (transaction F220), SAP financial reporting, project scope documents
Distribution Substations, Short Rural (including downstream LV network)	SAP reporting (transaction F220), SAP financial reporting, project scope documents
Distribution Substations, Long Rural (including downstream LV network)	SAP reporting (transaction F220), SAP financial reporting, project scope documents
Unmodelled Augmentation	SAP reporting (transaction F220), SAP financial reporting, project scope documents

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2009	N/A

Year	Methodology & Assumptions
2010	**Subtransmission Lines:** *Methodology* Incurred costs for subtransmission line asset class projects that are classed as capacity related augmentation. An annual project list was extracted using SAP reporting (transaction F220) to identify subtransmission line type projects. Each project was then individually assessed using the project database in SAP to determine whether the project was capacity related. Typically the project scope documents were used to make the determination. A percentage was then taken between the capacity related and unmodelled augmentation subtransmission lines project costs and applied against the annual overall subtransmission lines expenditure taken from SAP financial reporting. The capacity related portion of the expenditure is reported on in the subtransmission lines category, the unmodelled augmentation portion is added to the unmodelled augmentation category. The project costs cannot be summed as they include some overhead costs. Expenditure categories are grouped with the years 2010 to 2013 in one category. For this category the 2010, 2011, 2012 and 2013 costs are summed together. The 2014 category contains only the annual 2014 costs. *Assumptions* That all overhead percentages per project are equal. **Subtransmission Stations:** *Methodology* Incurred costs for subtransmission station asset class projects that are classed as capacity related augmentation. The Powercor network does not contain any subtransmission stations, so no expenditure was reported on **Zone Substations:** *Methodology* Incurred costs for zone substation asset class projects that are classed as capacity related augmentation. An annual project list was extracted using SAP reporting (transaction F220) to identify zone substation type projects. Each project was then individually assessed using the project database in SAP to determine whether the project was capacity related. Typically the project scope documents were used to make the determination. A percentage was then taken between the capacity related and unmodelled augmentation zone substation project costs and applied against the annual overall zone substation expenditure taken from SAP financial reporting. The capacity related portion of the expenditure is reported on in the zone substation category, the unmodelled augmentation portion is added to the unmodelled augmentation category. The project costs cannot be summed as they include some overhead costs. Expenditure categories are grouped with the years 2010 to 2013 in one category. For this category the 2010, 2011, 2012 and 2013 costs are summed together. The 2014 category contains only the annual 2014 costs. *Assumptions* That all overhead percentages per project are equal. **HV CBD Feeders:** *Methodology* Incurred costs for HV CBD feeder asset class projects that are classed as capacity related

Year	Methodology & Assumptions
	augmentation. The Powercor network does not contain any HV CBD feeders, so no expenditure was reported on. **HV Urban Feeders:** *Methodology* Incurred costs for HV urban feeder asset class projects that are classed as capacity related augmentation. An annual project list was extracted using SAP reporting (transaction F220) to identify HV urban feeder type projects. Each project was then individually assessed using the project database in SAP to determine whether the project was capacity related. Typically the project scope documents were used to make the determination. A percentage was then taken between the capacity related and unmodelled augmentation HV urban feeder project costs and applied against the annual overall HV urban feeder expenditure taken from SAP financial reporting. The capacity related portion of the expenditure is reported on in the HV urban feeder category, the unmodelled augmentation portion is added to the unmodelled augmentation category. The project costs cannot be summed as they include some overhead costs. Expenditure categories are grouped with the years 2010 to 2013 in one category. For this category the 2010, 2011, 2012 and 2013 costs are summed together. The 2014 category contains only the annual 2014 costs. *Assumptions* That all overhead percentages per project are equal. **HV Short Rural Feeders:** *Methodology* Incurred costs for HV short rural feeder asset class projects that are classed as capacity related augmentation. An annual project list was extracted using SAP reporting (transaction F220) to identify HV short rural feeder type projects. Each project was then individually assessed using the project database in SAP to determine whether the project was capacity related. Typically the project scope documents were used to make the determination. A percentage was then taken between the capacity related and unmodelled augmentation HV short rural feeder project costs and applied against the annual overall HV short rural feeder expenditure taken from SAP financial reporting. The capacity related portion of the expenditure is reported on in the HV short rural feeder category, the unmodelled augmentation portion is added to the unmodelled augmentation category. The project costs cannot be summed as they include some overhead costs. Expenditure categories are grouped with the years 2010 to 2013 in one category. For this category the 2010, 2011, 2012 and 2013 costs are summed together. The 2014 category contains only the annual 2014 costs. *Assumptions* That all overhead percentages per project are equal. **HV Long Rural Feeders:** *Methodology* Incurred costs for HV long rural feeder asset class projects that are classed as capacity related augmentation. An annual project list was extracted using SAP reporting (transaction F220) to identify HV long

Year	Methodology & Assumptions
	rural feeder type projects. Each project was then individually assessed using the project database in SAP to determine whether the project was capacity related. Typically the project scope documents were used to make the determination. A percentage was then taken between the capacity related and unmodelled augmentation HV long rural feeder project costs and applied against the annual overall HV long rural feeder expenditure taken from SAP financial reporting. The capacity related portion of the expenditure is reported on in the HV long rural feeder category, the unmodelled augmentation portion is added to the unmodelled augmentation category. The project costs cannot be summed as they include some overhead costs. Expenditure categories are grouped with the years 2010 to 2013 in one category. For this category the 2010, 2011, 2012 and 2013 costs are summed together. The 2014 category contains only the annual 2014 costs. *Assumptions* That all overhead percentages per project are equal. **Distribution Substations, CBD Feeders (including downstream LV network):** *Methodology* Incurred costs for distribution substation, CBD feeder (including downstream LV network) asset class projects that are classed as capacity related augmentation. The Powercor network does not contain any distribution substation, CBD feeders, so no expenditure was reported on. **Distribution Substations, Urban Feeders (including downstream LV network):** *Methodology* Incurred costs for distribution substation, urban feeder (including downstream LV network) asset class projects that are classed as capacity related augmentation. An annual project list was extracted using SAP reporting (transaction F220) to identify distribution substation, urban feeder type projects. Each project was then individually assessed using the project database in SAP to determine whether the project was capacity related. Typically the project scope documents were used to make the determination. A percentage was then taken between the capacity related and unmodelled augmentation distribution substation, urban feeder project costs and applied against the annual overall distribution substation, urban feeder expenditure taken from SAP financial reporting. The capacity related portion of the expenditure is reported on in the distribution substation, urban feeder category, the unmodelled augmentation portion is added to the unmodelled augmentation category. The project costs cannot be summed as they include some overhead costs. Expenditure categories are grouped with the years 2010 to 2013 in one category. For this category the 2010, 2011, 2012 and 2013 costs are summed together. The 2014 category contains only the annual 2014 costs. *Assumptions* That all overhead percentages per project are equal. **Distribution Substations, Short Rural Feeders (including downstream LV network):** *Methodology* Incurred costs for distribution substation, short rural feeder (including downstream LV network) asset class projects that are classed as capacity related augmentation. An annual project list was extracted using SAP reporting (transaction F220) to identify distribution substation, short rural feeder type projects. Each project was then individually assessed using the project database in SAP to determine whether the project was capacity

Year	Methodology & Assumptions
	related. Typically the project scope documents were used to make the determination. A percentage was then taken between the capacity related and unmodelled augmentation distribution substation, short rural feeder project costs and applied against the annual overall distribution substation, short rural feeder expenditure taken from SAP financial reporting. The capacity related portion of the expenditure is reported on in the distribution substation, short rural feeder category, the unmodelled augmentation portion is added to the unmodelled augmentation category. The project costs cannot be summed as they include some overhead costs. Expenditure categories are grouped with the years 2010 to 2013 in one category. For this category the 2010, 2011, 2012 and 2013 costs are summed together. The 2014 category contains only the annual 2014 costs. *Assumptions* That all overhead percentages per project are equal. **Distribution Substations, Long Rural Feeders (including downstream LV network):** *Methodology* Incurred costs for distribution substation, long rural feeder (including downstream LV network) asset class projects that are classed as capacity related augmentation. An annual project list was extracted using SAP reporting (transaction F220) to identify distribution substation, long rural feeder type projects. Each project was then individually assessed using the project database in SAP to determine whether the project was capacity related. Typically the project scope documents were used to make the determination. A percentage was then taken between the capacity related and unmodelled augmentation distribution substation, long rural feeder project costs and applied against the annual overall distribution substation, long rural feeder expenditure taken from SAP financial reporting. The capacity related portion of the expenditure is reported on in the distribution substation, long rural feeder category, the unmodelled augmentation portion is added to the unmodelled augmentation category. The project costs cannot be summed as they include some overhead costs. Expenditure categories are grouped with the years 2010 to 2013 in one category. For this category the 2010, 2011, 2012 and 2013 costs are summed together. The 2014 category contains only the annual 2014 costs. *Assumptions* That all overhead percentages per project are equal. **Unmodelled Augmentation:** *Methodology* Incurred costs for all asset type (subtransmission lines, zone substations, all HV feeders, all distribution substations) projects that are classed as unmodelled augmentation. An annual project list was extracted using SAP reporting (transaction F220), each project was individually assessed using the project database in SAP and a determination was made on whether the project was classified as unmodelled augmentation or capacity related. Unmodelled augmentation is a project that has been initiated by a non-demand driven trigger, and isn't captured as part of the AER's Augex Model. Such examples of unmodelled augmentation include voltage compliance works, re-arrangements to relieve transmission connection points, fault level driven works, security of supply works and zone substation automation works. The unmodelled augmentation costs that are calculated in all other asset type categories from the percentage splits are summed together and inputed to the unmodelled augmentation category. The percentage split methodology is explained in each of the individual asset type

Year	Methodology & Assumptions
	categories. Expenditure categories are grouped with the years 2010 to 2013 in one category. For this category the 2010, 2011, 2012 and 2013 costs are summed together. The 2014 category contains only the annual 2014 costs. *Assumptions* That all overhead percentages per project are equal.
2011	As per 2010.
2012	As per 2010.
2013	As per 2010.
2014	As per 2010.

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2009	N/A
2010	**Subtransmission Lines:** The capacity related expenditure in the annual project list only includes costs with some overheads. **Zone Substations:** The capacity related expenditure in the annual project list only includes costs with some overheads. **HV Urban Feeders:** The capacity related expenditure in the annual project list only includes costs with some overheads. **HV Short Rural Feeders:** The capacity related expenditure in the annual project list only includes costs with some overheads. **HV Long Rural Feeders:** The capacity related expenditure in the annual project list only includes costs with some overheads. **Distribution Substations, Urban Feeders (including downstream LV network):** The capacity related expenditure in the annual project list only includes costs with some overheads. **Distribution Substations, Short Rural Feeders (including downstream LV network):** The capacity related expenditure in the annual project list only includes costs with some overheads. **Distribution Substations, Long Rural Feeders (including downstream LV network):** The capacity related expenditure in the annual project list only includes costs with some overheads. **Unmodelled Augmentation:** The unmodelled augmentation expenditure in the annual project list only includes costs with some overheads.
2011	As per 2010.

Year	1. why was an estimate required, including why it is not possible to use actual data;
2012	As per 2010.
2013	As per 2010.
2014	As per 2010.

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2009	N/A
2010	**Subtransmission Lines:** Project list subtransmission lines capacity related costs include some overheads, so a percentage of these costs against the total direct annual subtransmission lines expenditure was used to best derive an estimation of the actual direct annual capacity related subtransmission lines expenditure. **Zone Substations:** Project list zone substations capacity related costs include some overheads, so a percentage of these costs against the total direct annual zone substation expenditure was used to best derive an estimation of the actual direct annual capacity related zone substation expenditure. **HV Urban Feeders:** Project list HV urban feeder capacity related costs include some overheads, so a percentage of these costs against the total direct annual HV urban feeder expenditure was used to best derive an estimation of the actual direct annual capacity related HV urban feeder expenditure. **HV Short Rural Feeders:** Project list HV short rural feeder capacity related costs include some overheads, so a percentage of these costs against the total direct annual HV short rural feeder expenditure was used to best derive an estimation of the actual direct annual capacity related HV short rural feeder expenditure. **HV Long Rural Feeders:** Project list HV long rural feeder capacity related costs include some overheads, so a percentage of these costs against the total direct annual HV long rural feeder expenditure was used to best derive an estimation of the actual direct annual capacity related HV long rural feeder expenditure. **Distribution Substations, Urban Feeders (including downstream LV network):** Project list distribution substation, urban feeder capacity related costs include some overheads, so a percentage of these costs against the total direct annual distribution substation, urban feeder expenditure was used to best derive an estimation of the actual direct annual capacity related distribution substation, urban feeder expenditure. **Distribution Substations, Short Rural Feeders (including downstream LV network):** Project list distribution substation, short rural feeder capacity related costs include some overheads, so a percentage of these costs against the total direct annual distribution substation, short rural feeder expenditure was used to best derive an estimation of the actual direct annual capacity related distribution substation, short rural feeder expenditure. **Distribution Substations, Long Rural Feeders (including downstream LV network):** Project list distribution substation, long rural feeder capacity related costs include some overheads, so a percentage of these costs against the total direct annual distribution substation, long rural feeder expenditure was used to best derive an estimation of the actual direct annual capacity related distribution substation, long rural feeder expenditure. **Unmodelled Augmentation:** Project list unmodelled augmentation costs include some overheads, so a percentage of these costs against each total direct annual asset type expenditure was used, then summed

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
	together, to best derive an estimation of the actual direct annual unmodelled augmentation expenditure.
2011	As per 2010.
2012	As per 2010.
2013	As per 2010.
2014	As per 2010.

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 2.4 Augex Model	
Table name: 2.4.6 CAPEX AND NET CAPACITY ADDED BY SEGMENT GROUP For customer-initiated & capacity-related augmentation	
BOP ID	RRPAL2.4BOP7

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

For the purposes of the *regulatory template*, '*customer*-initiated & capacity-related augmentation' refer to activities for which incurred costs are attributed to at least one of the following *AER* expenditure categories:

i. New *connection* - *augmentation* to *subtransmission lines*

ii. New *connection* - *augmentation* to *subtransmission substations* and *subtransmission switching stations*

iii. New *connection* - *augmentation* to *zone substations*

iv. New *connection* - *augmentation* to HV *CBD* feeders

v. New *connection* - *augmentation* to HV *urban* feeders

vi. New *connection* - *augmentation* to HV *short rural* feeders

vii. New *connection* - *augmentation* to HV *long rural* feeders

viii. New *connection* - *augmentation* to *distribution substations*, *CBD* (including downstream LV *network*)

ix. New *connection* - *augmentation* to *distribution substations*, *urban* (including downstream LV *network*)

x. New *connection* - *augmentation* to *distribution substations*, *short rural* (including downstream LV *network*)

xi. New *connection* - *augmentation* to *distribution substations*, *long rural* (including downstream LV *network*)

Please provide a Response in this box:

i	Not applicable no customer augmentation on subtransmission lines

ii	Not applicable no customer augmentation on subtransmission substations and subtransmission switching stations
iii	Not applicable no customer augmentation on zone substations
iv	Complies – note no CBD feeders in Powercor
v	Complies
vi	Complies
vii	Complies
viii	Complies – Note no augmentation to distribution substations, CBD in Powercor
ix	Complies
x	Complies
xi	Complies

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2010	2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:
The data was obtained from SAP via a Business Intelligence report
The data required for customer imitated augmentation has not been reported previously and is not available in the requested format that table 2.4.6 required.

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2009	Not applicable
2010	**Method** • In making offers to customers for availability of supply, modelling is required. One of the inputs is an estimate of the shared augmentation capital expenditure required due to that connection. • Each offer is allocated a Marginal Cost of Reinforcement MCR which is an indication of to what part of the existing distribution asset is the customer directly attributed assets being connected. MCR levels are Low Voltage, Distribution Substations, HV lines, Zone Substation, Sub Transmission. • The shared augmentation estimated capital expenditure and the A to P budget estimate were obtained from SAP via a Business Intelligence report. This information was per calendar year and included the MCR level. • The capital expenditure was summed per year by MCR level. Note MCR levels and shared augmentation capital expenditure were only available for years 2011, 2012, 2013 & 2014. For year 2010 the average percentage of shared augmentation to the project A to P for years 2011 to 2014 was used to determine a value for the shared augmentation for 2010. This estimated value of shared augmentation was then

Year	Methodology & Assumptions
	allocated across the MCR levels at the same percentage as the average for years 2011 to 2014. • The contribution model used to make supply offers includes a dollar per kVA for each MCR level. The individual dollar for the 2014 MCR's was used to calculate the MVA that was made available due to the shared augmentation. The $ per MVA value was divided into the capital expenditure for the same MCR level. This provided MVA amounts for LV, Distribution Subs, and HV Lines. Note no Customer supply offer incurred shared augmentation for Zone Substation or sub transmission lines. • The shared augmentation capital expenditure was now available in MCR levels of LV, Dist Substations and HV lines. These had to be allocated across the AER segment groups for table 2.4.6. Where there were multiple segments available the costs were allocated on an average of the same percentage used in the Distribution initiated augmentation plus customer projects estimate of the expenditure of the shared augmentation. • The allocation of the MVA was made on the same basis to the AER segments as the capital expenditure. **Assumptions** • The shared augmentation capital expenditure is assumed to be that actually incurred as the shared augmentation actual is not reported separately. The total project cost is recorded which includes the total of directly attributed work, Powercor funded work above the least cost technical acceptable requirements and the shared augmentation work. • The MCR level is to be used to allocate the capital expenditure for shared augmentation. I.e. it is assumed that the capital expenditure was incurred in augmenting that asset level that matched the MCR level. • Powercor did not have any High Voltage feeders CBD or Distribution substations - CBD (including downstream LV network) • The costs were not escalated for earlier years into $2015
2011	As per 2010 except the average of 2011 – to 2014 was not required
2012	As per 2010 except the average of 2011 – to 2014 was not required
2013	As per 2010 except the average of 2011 – to 2014 was not required
2014	As per 2010 except the average of 2011 – to 2014 was not required

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2009	Not applicable
2010	Powercor do not record the information required in the format required to complete the template. We do not record which part of the distribution system the augmentation occurred, the actual cost of the augmentation and the MVA that was made available by the augmentation.
2011	As per 2010
2012	As per 2010
2013	As per 2010
2014	As per 2010

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2009	Not applicable
2010	An estimate was used for the:

Year	2. **the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.**
	• value of actual shared augmentation expenditure • the part of the distribution system when the shared augmentation occurred • the amount of MVA that was made available by the shared augmentation. The estimate was the only way to provide the required data in the absence of any records to complete table 2.4.6
2011	As per 2010
2012	As per 2010
2013	As per 2010
2014	As per 2010

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name:	**2.13 Provisions**
Table name: TABLE 2.13.1 - CHANGES IN TOTAL PROVISIONS incl. RPM TABLE 2.13.2 - ALLOCATION OF MOVEMENT IN TOTAL PROVISIONS incl. RPM	
BOP ID	RRPAL2.13BOP1

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

17. PROVISIONS
17.1 For each of Powercor's provisions, provide the information required in regulatory template 2.13 in accordance with:
(a) regulatory template 2.13; and
(b) Australian Accounting Standard AASB 137 Provisions, Contingent Liabilities and Contingent Assets.
17.2 If, in a given year, there is an increase in the amount of a provision, provide reasons for this increase, including:
(a) the expected timing of any resulting outflows of economic benefits;
(b) an explanation of the uncertainties about the amounts or timing of the outflows;
(c) any supporting consultant's advice, including actuarial reports; and
(d) if there is no supporting consultant's advice, the process and assumptions Powercor used in determining the increase in the provision.
17.3 Provide the allocation of the movement in total provisions in, regulatory template 2.13.2 to:
(a) opex;
(b) as-incurred capex by roll forward model asset class; and
(c) other, where the movement in the provision is neither capex nor opex.
17.4 Identify and explain any assumptions applied for the allocation of asset class provided under paragraphs 17.3(b).

Please provide a Response in this box:
Powercor has reported provisions in accordance with regulatory template 2.13 and with AASB 137 Provisions.
Powercor has provided the allocation of the movement in total provisions to opex, as-incurred capex by asset class and other as per the requirements of regulatory template 2.13.2.

Powercor has provided reasons for movements in the template as per the categories in the RIN template. Powercor has also calculated the allocation of the movement in total provisions within template 2.13.2. As per RIN instructions 17.4, no assumptions have been made for the allocation of capex to the asset classes. See section D for further information.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2009	2010	2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response: The data for provisions for the years 2009-2014 has been sourced from the SAP accounting system. SAP is the primary financial reporting system and is the source of providing the audited statutory accounts for Powercor.

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2009	The SAP financial system is used to extract the information required to state the DNSP provision information. Using the audited statutory accounts for Powercor, the business uses cost elements within SAP in order to disaggregate the data for the purposes of apportioning provisions to the applicable capex and opex regulatory segments. Data contained in these tables is consistent with the data reported within the Historical Annual RINs. Specific Employee Benefits Provisions Treatment As the provisions are attached to employees and not to capital and operating activities, employee entitlement provisions are allocated between capital and operating costs using labour reported in the annual Regulatory Accounting Statements (Labour Cost – Matrix template) as the allocator. The Long Service Leave Bond adjustment is allocated solely to opex and the remainder of the movement is split between opex and capex using the above allocation... The movement in total provisions allocated to as-incurred capex by asset class is prorated based on actual capex for those asset classes. The actual capex figures are pulled from the Annual Financial RIN.
2010	As per 2009
2011	As per 2009

Year	Methodology & Assumptions
2012	As per 2009
2013	As per 2009
2014	As per 2009

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2009	Not applicable
2010	Not applicable
2011	Not applicable
2012	Not applicable
2013	Not applicable
2014	Not applicable

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2009	Not applicable
2010	Not applicable
2011	Not applicable
2012	Not applicable
2013	Not applicable
2014	Not applicable

AER RESET RIN – HISTORICAL DATA ONLY

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name:	**2.14 Forecast Price Changes**
Table name: TABLE 2.14.1 - FORECAST LABOUR AND MATERIALS PRICE CHANGES	
Item	Consumer Price Index Growth
BOP ID	RRCP2.14BOP1

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

The DNSP must provide all forecast price changes used to forecast opex and capex, including forecast changes in CPI. Forecast price changes must be expressed in real terms, except for CPI. If the same escalators are not used for capex and opex, report capex and opex escalators separately. Add additional rows as required. If price changes for a given year were not used to forecast either opex or capex enter '0' for that year.

Please provide a Response in this box:
Powercor has provided all forecast price changes used to forecast opex and capex, including forecast changes in CPI. Forecast price changes have been expressed in real terms, except for CPI. The same escalators have been used for capex and opex.

This box should provide an affirmative response dictating that the RIN requirements (posted in the box above) have been met.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:
Source information include:
- Australian Bureau of Statistics Consumer Price Index Series A2325846C

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2011	The consumer price index data is sourced directly from the Australian Bureau of Statistics. The consumer price index is the same for both opex and capex.
2012	Same as 2011
2013	Calculate the growth in the ABS CPI series from June 2012 to June 2013
2014	Calculate the growth in the ABS CPI series from June 2013 to June 2014

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2011	n/a
2012	n/a
2013	n/a
2014	n/a

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2011	n/a
2012	n/a
2013	n/a
2014	n/a

AER RESET RIN – HISTORICAL DATA ONLY

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 2.14 Forecast Price Changes	
Table name: TABLE 2.14.1 - FORECAST LABOUR AND MATERIALS PRICE CHANGES	
Item	Contracts price growth
BOP ID	RRPAL2.14BOP2

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

The DNSP must provide all forecast price changes used to forecast opex and capex, including forecast changes in CPI. Forecast price changes must be expressed in real terms, except for CPI. If the same escalators are not used for capex and opex, report capex and opex escalators separately. Add additional rows as required. If price changes for a given year were not used to forecast either opex or capex enter '0' for that year.

Please provide a Response in this box:
Powercor has provided all forecast price changes used to forecast opex and capex, including forecast changes in CPI. Forecast price changes have been expressed in real terms, except for CPI. The same escalators have been used for capex and opex..

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g.

it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response: Source information include: • Australian Bureau of Statistics Construction Wage Price Index (**WPI**) for Victoria, series 'Total hourly rates of pay excluding bonuses, State by Industry, All Sectors', sourced by the CIE; • Australian Bureau of Statistics Consumer Price Index Series A2325846C

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2011	The contracts price growth rates are reported in real terms as required. The contracts price growth rates are the same for both opex and capex Calculate the growth in the ABS construction sector WPI from June 2010 to June 2011. Convert to real terms by applying the ABS CPI series.
2012	The contracts price growth rates are reported in real terms as required. The contracts price growth rates are the same for both opex and capex Calculate the growth in the ABS construction sector WPI from June 2011 to June 2012. Convert to real terms by applying the ABS CPI series.
2013	The contracts price growth rates are reported in real terms as required. The contracts price growth rates are the same for both opex and capex Calculate the growth in the ABS construction sector WPI from June 2012 to June 2013. Convert to real terms by applying the ABS CPI series.
2014	The contracts price growth rates are reported in real terms as required. The contracts price growth rates are the same for both opex and capex Calculate the growth in the ABS construction sector WPI from June 2013 to June 2014. Convert to real terms by applying the ABS CPI series.

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2011	Business systems do not capture the data in the form required
2012	As for 2011
2013	As for 2011
2014	As for 2011

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2011	The Business uses external contractors to deliver specialised services, for example vegetation management, asset inspection, electrical construction, civil works and traffic management. The primary nature of these contracts is for labour-based services. The Australian Bureau of

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
	Statistics' construction sector WPI most closely reflect the types of labour skills required to deliver these services.
2012	As for 2011
2013	As for 2011
2014	As for 2011

AER RESET RIN – HISTORICAL DATA ONLY

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 2.14 Forecast Price Changes	
Table name: TABLE 2.14.1 - FORECAST LABOUR AND MATERIALS PRICE CHANGES	
Item	Internal Labour Price Growth
BOP ID	RRPAL2.14BOP3

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

The DNSP must provide all forecast price changes used to forecast opex and capex, including forecast changes in CPI. Forecast price changes must be expressed in real terms, except for CPI. If the same escalators are not used for capex and opex, report capex and opex escalators separately. Add additional rows as required. If price changes for a given year were not used to forecast either opex or capex enter '0' for that year.

Please provide a Response in this box:
Powercor has provided all forecast price changes used to forecast opex and capex, including forecast changes in CPI. Forecast price changes have been expressed in real terms, except for CPI. The same escalators have been used for capex and opex.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g.

it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:
Source information include:

- Powercor Workplace Agreement with ASU, APESMA and NUW 2007
- Powercor Enterprise Agreement with ASU, APESMA and NUW 2011
- Powercor Enterprise Agreement with ASU, APESMA and NUW 2013
- Powercor Workplace Agreement with CEPU 2007
- Powercor Enterprise Agreement with CEPU 2011
- Powercor and CitiPower Enterprise Agreement with CEPU
- Australian Bureau of Statistics Consumer Price Index series A2325846C

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2011	The labour growth rates are reported in real terms as required. The labour growth rates are the same for both opex and capex For each union group, derive an annual wage growth rate based on the agree EBA wage growth rates and applicable dates. Derive a single wage growth rate by taking a weighted average of the annual growth rate for each union group based on the proportion of employees in each union group. Convert the weighted average nominal wage growth rate to real terms using June to June inflation rate derived from the ABS CPI series.
2012	Same as 2011
2013	Same as 2011
2014	Same as 2011

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2011	Business systems do not capture the data in the form required
2012	As for 2011
2013	As for 2011
2014	As for 2011

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2011	The EBAs specify the wage growth rates that the Business is obligated to pay its employees. An employee weighted average of the annualised EBA growth rates therefore provides the best estimate of the actual labour price growth rates paid by the business.
2012	As for 2011
2013	As for 2011
2014	As for 2011

AER RESET RIN – HISTORICAL DATA ONLY

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 2.14 Forecast Price Changes	
Table name: TABLE 2.14.1 - FORECAST LABOUR AND MATERIALS PRICE CHANGES	
Item	Materials Price Growth
BOP ID	RRPAL2.14BOP4

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

The DNSP must provide all forecast price changes used to forecast opex and capex, including forecast changes in CPI. Forecast price changes must be expressed in real terms, except for CPI. If the same escalators are not used for capex and opex, report capex and opex escalators separately. Add additional rows as required. If price changes for a given year were not used to forecast either opex or capex enter '0' for that year.

Please provide a Response in this box:
Powercor has provided all forecast price changes used to forecast opex and capex, including forecast changes in CPI. Forecast price changes have been expressed in real terms, except for CPI. The same escalators have been used for capex and opex.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g.

it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:
Source information include: • Jacobs' provided the historical growth in prices for key categories of distribution equipment used by the Business. Jacobs derives its price indices using information on raw materials prices in US dollars, the US/AUD exchange rate and proprietary information of the share of raw materials contained in each category of distribution equipment • Australian Bureau of Statistics Consumer Price Index series A2325846C.

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2011	The materials price growth rates are reported in real terms as required. The materials price growth rates are the same for both opex and capex Calculate the change in Jacobs nominal price indices then convert the growth rate to real terms using the ABS CPI series.
2012	Same as 2011.
2013	Same as 2011.
2014	Same as 2011.

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2011	Business systems do not capture the data in the form required.
2012	As for 2011
2013	As for 2011
2014	As for 2011

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2011	Jacobs' method relies directly on the actual changes in raw materials and foreign exchange and Jacobs allocation of raw materials in distribution equipment is derived from engineering knowledge and experience. Jacobs method is commonly applied by electricity networks and we are not aware of any alternative method which would better reflect actual materials prices
2012	As for 2011
2013	As for 2011
2014	As for 2011

AER RESET RIN – HISTORICAL DATA ONLY

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name:	**2.17 Step Changes**
Table name:	TABLE 2.17.1 - FORECAST OPEX STEP CHANGES FOR STANDARD CONTROL SERVICES
BOP ID	RRPAL2.17BOP1

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

4.1 For all step changes in forecast expenditure (including those due to changes in regulatory obligations or requirements and those due to changes in Powercor's own policies and strategies) provide:

(a) in regulatory template 2.17.1 and regulatory template 2.17.2 the quantum of the step change Powercor:

(i) forecasts for each year of the forthcoming regulatory control period;

(ii) if applicable, has incurred, or expects to incur, in the current regulatory control period relative to expenditure previously approved by the AER.

(b) a description of the step change

Please provide a Response in this box:

As per the RIN requirements, Powercor has reported the actual and forecast expenditure incurred for each step change that was accepted by the AER for the 2011–2015 regulatory control period. These step changes include the following:

- Customer charter;
- Enhanced customer communications;
- At-risk townships; [
- Outcomes monitoring;
- National planning framework;
- Insurance; and
- Electric Line Clearance regulations.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

Actual data is used for our Insurance and Electric Line Clearance step changes.

2011	2012	2013	2014

Estimated data is used for the remaining step changes.

2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:

The source data for the following historical step changes (or part thereof) is SAP:

- Customer charter;
- Enhanced customer communications;
- Insurance;
- Electric Line Clearance regulations; and
- National planning framework.

For the reasons set out in Section E, the At-risk townships and Outcomes monitoring step changes have been estimated to equal the allowance 'accepted' by the AER in its final decision for the 2011–2015 regulatory control period. As such, the AER's final decision is the source data.

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2011	Historical step changes have been determined using 2009 as the base year (consistent with the AER's final decision for the 2011–2015 regulatory control period). That is, our 2009 revealed costs have been subtracted from our actual expenditure during the 2011–2015 regulatory control period. Where 2009 expenditure was greater than zero, our 2009 revealed costs have been escalated using the output and real price growth escalators accepted by the AER in its 2011–2015 regulatory control period. This escalation has also been applied to the At-risk townships and Outcomes monitoring step change allowance. All expenditure has been reported in $2015. If required, costs were allocated between CitiPower and Powercor based on our split of customer numbers in 2011 (the start of the 2011–2015 regulatory control period).
2012	As above.
2013	As above.

Year	Methodology & Assumptions
2014	As above.

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2011	We do not capture incremental expenditure for individual step changes, as we do not separate specific step change expenditure from broader expenditure categories. An estimate, therefore, is required. The exceptions to the above are the step changes for our Insurance and Electric Line Clearance. Our vegetation clearance requirements are undertaken through a fixed contract with our vegetation management provider. Our insurance premiums are also reported separately in our accounts.
2012	As above.
2013	As above.
2014	As above.

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2011	We have estimated our actual expenditure on historical step changes using actual costs to the extent possible. As outlined previously, however, we do not report costs for given step changes, and this is particularly the case for internal labour costs. The basis for each step change estimate is set out below: **Customer charter** This step change has been estimated using invoiced costs (where applicable), plus internal labour costs associated with managing the project. The internal labour costs have been assumed to equal the internal labour costs accepted by the AER in its final decision for the 2011–2015 regulatory control period (as we do not separately report incremental labour costs for specific step changes). The customer charter step change is for 2011 only. **Enhanced customer communications** Our customer communications expenditure has been estimated using invoiced costs for projects that communicate to customers about who we are, what our role is, and how we can be contacted. This is consistent with our requirements under the Electricity Distribution Code. **At-risk townships** The At-risk townships step change included expenditure for various activities that were broadly focused on reducing bushfire risk in specific areas. Our actual expenditure on these programs is now embedded in our asset inspection, vegetation clearance and bushfire safety programs. Further, the actual programs undertaken may vary through time, as new technology and information become available, or as Government policy or strategic focus changes. Given the above, we have estimated our expenditure for this step change to be equal to the allowance set out in the AER's final decision for the 2011–2015 regulatory control period. **Outcomes monitoring** The Outcomes monitoring step change included expenditure (such as internal labour, audit and legal costs) for specific reporting requirements set out in the AER's final decision for the 2011–2015 regulatory control period. Our actual expenditure on increased reporting requirements during the 2011–2015 regulatory control period, however, has increased significantly due to the changes outlined in this step change, as well as other changes in the level of information reporting required by the AER. As such, our actual expenditure on the reporting requirements that are the subject of this step change is unclear. Instead, we have

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
	estimated our expenditure for this step change to be equal to the allowance set out in the AER's final decision for the 2011–2015 regulatory control period. **National planning framework** This step change was for increased expenditure forecast to be incurred as a result of the AEMC's rule changes to the distribution network planning and expansion framework. The new rules commenced from January 2013, and included the requirement to develop a distribution annual planning report (DAPR), a demand side engagement (DSE) strategy, and undertake a greater volume of regulatory investment tests (RIT–D). Our expenditure has been estimated based on estimates of internal staff hours, plus external invoices (where applicable). These estimates are required as we do not record the incremental costs associated with specific step changes.
2012	As above.
2013	As above.
2014	As above.

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name:	**6.1 Telephone Answering**
Table name: 6.1.1 – Telephone Answering Data	
Variable Name	Total Number of Calls Received
BOP ID	RRPAL6.1BOP1

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". Only copy the requirements specific to the information covered by this Basis of Preparation document.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

Powercor is required to report telephone answering data in accordance with table 6.1.1. The same definitions for telephone answering data has been used as in previous Annual RIN's (Non-Financial).

Please provide a Response in this box:

Powercor has reported the Total Number of Calls Received as required by the AER.

The AER Definition of Total Number of Calls Received is:

The total number of calls to the fault line to be reported, including any answered by an automated response service and terminated without being answered by an operator. Excludes missed calls where the fault line is overloaded.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2010	2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Due to a change in telephony systems and reporting platforms we no longer have access to the original source for any call data before April 21st 2013. All call data though was stored in pivot tables linked to SQL tables and saved in Excel files for each calendar month for the entire Rest RIN period. Post April 21st 2014 data is pulled from the Exony reporting system and is stored in Excel databases that link to Pivot tables in other excel reports. The data for the Reset RIN was obtained from these excel files (for both pre/post 21/04/2014). Each monthly file has data for each day and covers a number of metrics/variables including all the ones required by the Reset RIN. Extracting the data is simply a matter of access a file for each month of the 5 year period and copying the relevant data. There is a tab for CitiPower called CP FAULTS and for Powercor called PAL Faults.

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.

(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2010	Data has been extracted from previous reporting systems and stored in Pivot tables within Excel reporting files. The data is collated according to the business lines and the relevant metrics required for telephone answering reporting. This data is easily accessible for the entire 5 year Reset RIN period
2011	Refer 2010
2012	Refer 2010
2013	Refer 2010
2014	Customers that call the Faults line enter the phone system through an Interactive Voice Response (IVR) system. Based on the menu options they choose they are routed to the relevantly skilled agents and assigned queue priorities. All calls that enter the IVR are assigned a call type. Call types ending with "_IVR" are used to identify the total number of calls that have been offered to that IVR, which includes any call that receives an automated response service (such as estimated fault restoration time) The reporting system counts the calls against many metrics, including 'Calls Offered' Because of this, and the fact that call types denoted with "_IVR" include all calls for that call type/phone line, we are able to easily count the total number of calls to the call centre fault line as per the AER definition Data is extracted from the Exony reporting system and is then stored in Excel databases that link to Pivot Tables in Excel reports. This collates the data for the relevant reporting business and performs any calculations necessary to report on Grade of Service figures.

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2010	n/a
2011	n/a
2012	n/a
2013	n/a
2014	n/a

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2010	n/a
2011	n/a
2012	n/a
2013	n/a
2014	n/a

AER RESET RIN – HISTORICAL DATA ONLY

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 6.1 Telephone Answering	
Table name: 6.1.1 – Telephone Answering Data	
Variable Name	Calls to payment lines and automated interactive services
BOP ID	RRPAL6.1BOP2

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". Only copy the requirements specific to the information covered by this Basis of Preparation document.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

Powercor is required to report telephone answering data in accordance with table 6.1.1. The same definitions for telephone answering data has been used as in previous Annual RIN's (Non-Financial).

Please provide a Response in this box:

Powercor has reported the Calls to payment lines and automated interactive services as required by the AER.

There is no AER Definition for this metric but it is a derived value that can be calculated with the following variables:

Total Number of Calls MINUS (Number of Calls Received + Calls abandoned within 30 seconds)

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2010	2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Due to a change in telephony systems and reporting platforms we no longer have access to the original source for any call data before April 21st 2013. All call data though was stored in pivot tables linked to SQL tables and saved in Excel files for each calendar month for the entire Rest RIN period.

Post April 21st 2014 data is pulled from the Exony reporting system and is stored in Excel databases that link to Pivot tables in other excel reports.

The data for the Reset RIN was obtained from these excel files (for both pre/post 21/04/2014. Each monthly file has data for each day and covers a number of metrics/variables including all the ones required by the Reset RIN.

Extracting the data is simply a matter of accessing a file for each month of the 5 year period and copying the relevant data. There is a tab for CitiPower called CP FAULTS and for Powercor called PAL Faults.

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2010	Data has been extracted from previous reporting systems and stored in Pivot tables within Excel reporting files. The data is collated according to the business lines and the relevant metrics required for telephone answering reporting. This data is easily accessible for the entire 5 year Reset RIN period
2011	Refer 2010
2012	Refer 2010
2013	Refer 2010
2014	<u>Total Number of Calls</u> The total number of calls to the fault line to be reported, including any answered by an automated response service and terminated without being answered by an operator. Excludes missed calls where the fault line is overloaded. MINUS <u>(Number of Calls Received + Calls abandoned)</u> <u>Number of Calls Received</u> The number of calls to the fault line excluding: (a) calls to payment lines and automated interactive services; (b) calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator (where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned). <u>Calls Abandoned</u> The number of calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator

Year	Methodology & Assumptions
	As this is derived variable, and all the base variables are easily accessible directly from the reporting systems and excel files where the data for past years is stored, we have a field that captures this specific metric. It is referred to as IVR Handled.

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2010	n/a
2011	n/a
2012	n/a
2013	n/a
2014	n/a

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2010	n/a
2011	n/a
2012	n/a
2013	n/a
2014	n/a

Basis of Preparation (BOP) Template
The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 6.1 Telephone Answering	
Table name: 6.1.1 – Telephone Answering Data	
Variable Name	Calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator
BOP ID	RRPAL6.1BOP3

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". Only copy the requirements specific to the information covered by this Basis of Preparation document.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

Powercor is required to report telephone answering data in accordance with table 6.1.1. The same definitions for telephone answering data has been used as in previous Annual RIN's (Non-Financial).

Please provide a Response in this box:

Powercor has reported the Calls abandoned by the customer within 30 seconds as required by the AER.

The AER Definition of Calls Abandoned is:

The number of calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2010	2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Due to a change in telephony systems and reporting platforms we no longer have access to the original source for any call data before April 21st 2013. All call data though was stored in pivot tables linked to SQL tables and saved in Excel files for each calendar month for the entire Rest RIN period. Post April 21st 2014 data is pulled from the Exony reporting system and is stored in Excel databases that link to Pivot tables in other excel reports. The data for the Reset RIN was obtained from these excel files (for both pre/post 21/04/2014). Each monthly file has data for each day and covers a number of metrics/variables including all the ones required by the Reset RIN. Extracting the data is simply a matter of accessing a file for each month of the 5 year period and copying the relevant data. There is a tab for Powercor called PAL FAULTS.

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2010	Data has been extracted from previous reporting systems and stored in Pivot tables within Excel reporting files. The data is collated according to the business lines and the relevant metrics required for telephone answering reporting. This data is easily accessible for the entire 5 year Reset RIN period
2011	Refer 2010
2012	Refer 2010
2013	Refer 2010
2014	Customers that call the Faults line enter the phone system through an Interactive Voice Response (IVR) system. Based on the menu options they choose they are routed to the relevantly skilled agents and assigned queue priorities. The telephony system assigns them a certain call type only when they have been routed to queue to an agent (i.e. Not calls to a payment line or automated service) The reporting system counts the calls against many metrics, including 'Calls Offered' and 'Abandoned in 30 seconds'. Because of this, and the fact that only certain call types have been queued to an agent, we are able to easily count the number of calls abandoned by the customer within 30 seconds of the call being queued for response by an agent

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2010	n/a
2011	n/a
2012	n/a
2013	n/a
2014	n/a

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2010	n/a
2011	n/a
2012	n/a
2013	n/a
2014	n/a

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 6.1 Telephone Answering	
Table name: 6.1.1 – Telephone Answering Data	
Variable Name	Calls to the fault line answered in 30 seconds
BOP ID	RRPAL6.1BOP4

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". Only copy the requirements specific to the information covered by this Basis of Preparation document.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

Powercor is required to report telephone answering data in accordance with table 6.1.1. The same definitions for telephone answering data has been used as in previous Annual RIN's (Non-Financial).

Please provide a Response in this box:

Powercor has reported the Total Number of Calls Received as required by the AER.

The AER Definition of Calls Answered within 30 seconds is:

The total number of calls to the fault line answered in 30 seconds where the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered by any response) and the caller speaks with a human operator, but excluding:
(a) the time that the caller is connected to an automated interactive service that provides substantive information;
(b) calls to payment lines and automated interactive services;
(c) calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator (where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned); and
(d) being placed in an automated queuing system does not constitute a response.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2010	2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Due to a change in telephony systems and reporting platforms we no longer have access to the original source for any call data before April 21st 2013. All call data though was stored in pivot tables linked to SQL tables and saved in Excel files for each calendar month for the entire Rest RIN period.

Post April 21st 2014 data is pulled from the Exony reporting system and is stored in Excel databases that link to Pivot tables in other excel reports.

The data for the Reset RIN was obtained from these excel files (for both pre/post 21/04/2014). Each monthly file has data for each day and covers a number of metrics/variables including all the ones required by the Reset RIN.

Extracting the data is simply a matter of access a file for each month of the 5 year period and copying the relevant data. There is a tab for CitiPower called CP FAULTS and for Powercor called PAL Faults.

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2010	Data has been extracted from previous reporting systems and stored in Pivot tables within Excel reporting files. The data is collated according to the business lines and the relevant metrics required for telephone answering reporting. This data is easily accessible for the entire 5 year Reset RIN period
2011	Refer 2010
2012	Refer 2010
2013	Refer 2010
2014	Customers that call the Faults line enter the phone system through an Interactive Voice Response (IVR) system. Based on the menu options they choose they are routed to the relevantly skilled agents and assigned queue priorities. The telephony system assigns them a certain call type only when they have been routed to queue to an agent (i.e. Not calls to a payment line or automated service) The reporting system records counts the calls against many metrics, including 'Answered in 30 seconds' and 'Abandoned in 30 seconds'. Because of this, and the fact that only certain call types have been queued to an agent, we are able to easily count the number of calls that have waited 30 seconds or less before being answered by an agent.

Year	Methodology & Assumptions

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2010	n/a
2011	n/a
2012	n/a
2013	n/a
2014	n/a

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2010	n/a
2011	n/a
2012	n/a
2013	n/a
2014	n/a

AER RESET RIN – HISTORICAL DATA ONLY

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name:	**7.4 Shared Assets**
Table name: TABLE 7.4.1 - TOTAL UNREGULATED REVENUE EARNED WITH SHARED ASSETS TABLE 7.4.2 - SHARED ASSET UNREGULATED SERVICES - APPORTIONMENT METHODOLOGY	
BOP ID	RRPAL7.4BOP1 v0.1

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

24. SHARED ASSETS
24.1 Provided Powercor's shared assets information in regulatory template 7.4.

Please provide a Response in this box:
Powercor has provided shared assets information in accordance with the requirements of regulatory template 7.4.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2009	2010	2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:
The data for unregulated revenues from shared assets for the years 2009-2014 has been sourced

from the SAP accounting system. SAP is the primary financial reporting system and is the source of providing the audited statutory accounts for Powercor.

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2009	The SAP financial system is used to extract the information required by category and regulatory segment. Using the audited statutory accounts for Powercor, the business uses cost elements within SAP in order to allocate costs between the regulatory segments in accordance with the cost allocation methodology. There is no apportionment methodology applied in determining the unregulated revenue from shared assets.
2010	As per 2009
2011	As per 2009
2012	As per 2009
2013	As per 2009
2014	As per 2009

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2009	Not Applicable
2010	Not Applicable
2011	Not Applicable
2012	Not Applicable
2013	Not Applicable
2014	Not Applicable

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2009	Not Applicable
2010	Not Applicable
2011	Not Applicable
2012	Not Applicable
2013	Not Applicable
2014	Not Applicable

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name:	**7.5 EBSS**
Table name: Table 7.5.1.1 - Opex allowance applicable to EBSS (EBSS target)	
BOP ID	RRPAL7.5BOP1

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

22.1 To calculate the carryover amounts that arise from applying the efficiency benefit sharing scheme during Powercor's current regulatory control period:
(a) provide the forecast and actual operating expenditure amounts in regulatory template 7.5;
(b) identify all changes to Powercor's Capitalisation Policy during the current regulatory control period

Please provide a Response in this box:
22.1(a) Powercor has provided the relevant forecast and actual operating expenditure in regulatory template 7.5
(b) Powercor has identified no changes to the Capitalisation Policy during the current regulatory period.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g. it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response: Variables: Total opex allowance, debt raising costs, self-insurance, defined benefit, superannuation, non-network alternatives, DMIA, GSL payments, The above data categories were all extracted from the AER Final Determination 2011-2015 Capitalisation Policy Changes: No changes have occurred during the regulatory period so no data was provided. Variables: Other adjustments or exclusions required by the EBSS • Incremental cash audit costs were sourced from SAP.

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2011	**Response:** Variables: Total opex allowance, debt raising costs, self-insurance, defined benefit, superannuation, non-network alternatives, DMIA, GSL payments, capitalisation policy changes • 'Total Uncontrollable O & M - not included in EBSS' from the AER 2011-15 final determination with • the vegetation management step change allowance substituted with the final appeal allowance; plus • DMIA allowance from the AER 2011-15 final determination PTRM; plus • Debt raising costs from the AER 2011-15 final determination PTRM. • Note: the above costs have been extracted from and in reference to the AER 2011-15 final determination. Variables: debt raising costs • The Final Determination states that for the purpose of calculating carryover amounts, the AER will exclude debt raising costs. Variables: Network growth adjustment • The Final Determination states that for the purpose of calculating carryover amounts, the AER will substitute actual values for customer numbers, the number of distribution transformers and zone substation capacity MVA and line length for the years 2011 – 2014 and a revised forecast for 2015, for the forecasts of these metrics used in the Final Decision using the scale escalation method described in appendix J of the Final Decision. Benchmark EBSS opex has been calculated in accordance with this requirement by taking the AER 2011-15 final determination opex model, updated for vegetation management appeal outcome, and updating for 2011-14 actual network growth inputs sourced from the Economic Benchmarking RIN. Variables: Other adjustments or exclusions required by the EBSS • The Final Determination states that cost adjustments for the EBSS calculation include the adjustments set out in section 2.3.2 of the EBSS. One of the EBSS adjustments is

Year	Methodology & Assumptions
	adjustments to forecast operating expenditure for any changes in responsibilities that result from compliance with a new or amended law or licence, or other statutory or regulatory requirement. In 2014 we were required for the first time to provide an audited Economic Benchmarking RIN and an audited Category Analysis RIN. The incremental costs incurred for preparation of these RINs and their audit were not forecast in the Final Determination, and have therefore been added to benchmark operating expenditure used to calculate EBSS carryover amounts to be applied in 2016 – 2020. Incremental cash audit costs were sourced from SAP.
2012	Same as 2011
2013	Same as 2011
2014	Same as 2011

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2011	Not applicable
2012	Not applicable
2013	Not applicable
2014	Not applicable

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2011	Not applicable
2012	Not applicable
2013	Not applicable
2014	Not applicable

Basis of Preparation (BOP) Template

The purpose of this template is to explain, for all historical information in the Reset RIN templates, the basis upon which the Businesses prepared information to populate the input cells. It is used to demonstrate to the AER that the information provided is compliant with the requirements of the Reset RIN Notice.

This information must be provided for each variable and must be accurately described as it will be audited and provided to the AER.

Please use plain English, complete sentences and avoid acronyms. A "QA Review checklist" has also been prepared to assist you with completing this BOP.

Tab name: 7.5 EBSS	
Table name: Table 7.5.1.2 - Actual and estimated opex applicable to EBSS	
BOP ID	RRPAL7.5BOP2

A. Demonstrate how the information provided is consistent with the requirements of the Reset RIN Notice (refer AER Reset RIN Schedule 1 Section 36.2(a))

Please note that you will need to copy and paste the requirements from the Reset RIN itself. The requirements may be found in "Schedule 1", "Appendix E: Principles and Requirements", and/or "Appendix F: Definitions". **Only copy the requirements specific to the information covered by this Basis of Preparation document**.

The intent of this section is for you to demonstrate and confirm, that the data provided complies with the instructions and definitions specified in the Reset RIN.

Copy and paste the requirements in this box:

22.1 To calculate the carryover amounts that arise from applying the efficiency benefit sharing scheme during Powercor's current regulatory control period:
(a) provide the forecast and actual operating expenditure amounts in regulatory template 7.5;
(b) identify all changes to Powercor's Capitalisation Policy during the current regulatory control period

Please provide a Response in this box:
22.1(a) Powercor has provided the relevant forecast and actual operating expenditure in regulatory template 7.5
(b) Powercor has identified no changes to the Capitalisation Policy during the current regulatory period.

B. Actual vs. Estimated Data colour coding

For each year, please shade ACTUAL data green; and ESTIMATED/derived data red
(Delete any years that are not applicable.)

2011	2012	2013	2014

C. Source (refer AER Reset RIN Schedule 1 Section 36.2(b))

Please explain the source from where the data has been obtained for each year (i.e. GIS, SAP, OAS, Audited financial statements etc.). If the data has not been obtained from the *originating source* (e.g.

it was sourced from a report such as the Annual Regulatory Performance Report etc.), the originating source for data in the performance report/RIN will need to be provided as well.

Response:
Variables: total opex • Sourced from annual RINs, Income statement, the sum of 'operating expense s' and 'maintenance' Variables: approved excludable costs, debt raising costs, self-insurance, defined benefit superannuation, non-network alternatives, DMIA, GSL payments, Opex associated with approved cost pass through, capitalisation changes • Sourced from annual RINs, EBSS template Variables: movements in provisions relating to opex • Sourced from opex component of provisions as reported in the 'Provisions' template of the Economic Benchmarking RIN Variables: other adjustments or exclusions required by EBSS • Licence fee sourced from 'Operating B' template of Annual RIN

D. Methodology & Assumptions (refer AER Reset RIN Schedule 1 Section 36.2(c))

Please explain for each year, the methodology applied including any assumptions made to determine the final value populated in the RIN. Where applicable please reference the relevant processes and procedures used.
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	Methodology & Assumptions
2011	Variables: total opex • Sourced from annual RINs, Income statement, the sum of 'operating expense s' and 'maintenance' Variables: approved excludable costs, debt raising costs, self-insurance, defined benefit superannuation, non-network alternatives, DMIA, GSL payments, Opex associated with approved cost pass through, capitalisation changes • Sourced from annual RINs, EBSS template Variables: movements in provisions relating to opex • Sourced from opex component of provisions as reported in the 'Provisions' template of the Economic Benchmarking RIN Variables: other adjustments or exclusions required by EBSS • Licence fee sourced from 'Operating B' template of Annual RIN
2012	Same as 2011
2013	Same as 2011
2014	Same as 2011

E. Estimated or Derived Data (refer AER Reset RIN Schedule 1 Section 36.2(d))

For those years where data has been estimated or derived from other data, please explain:
(If the same explanation applies over other years, just refer to the applicable year. Delete any years that are not applicable.)

Year	1. why was an estimate required, including why it is not possible to use actual data;
2011	Not applicable
2012	Not applicable

Year	1. why was an estimate required, including why it is not possible to use actual data;
2013	Not applicable
2014	Not applicable

Year	2. the basis for the estimate, including the approach used, assumptions made and the reason(s) why the estimate is the best estimate, given the information sought in the Notice.
2011	Not applicable
2012	Not applicable
2013	Not applicable
2014	Not applicable