2017 RIN

Basis of Preparation

Economic Benchmarking

Document No: 2017 [CP] [EB] RIN BOP

Revision: 1.0

Overview

CitiPower is required to prepare a Basis of Preparation document which must,

a) demonstrate how the information provided is consistent with the requirements of the Notice;

b) explain the source from which CitiPower obtained the information provided;

c) explain the methodology CitiPower applied to provide the required information, including any assumptions CitiPower made;

d) advise if the information is actual or estimate;

e) explain circumstances where CitiPower cannot provide input for a variable using actual information, and therefore must provide estimated information:

   i. why an estimate was required, including why it was not possible for CitiPower to use actual information;

   ii. the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is CitiPower's best estimate, given the information sought in the Notice.

In accordance with the requirements above, this document provides details to support the information provided by CitiPower in the Microsoft Excel workbooks titled:

- 2017 [CP] [EB] RIN Template Export - Actual
- 2017 [CP] [EB] RIN Template Export - Estimated
- 2017 [CP] [EB] RIN Template Export - Consolidated

To satisfy the requirements of the *Notice*, the following information has been provided for each RIN table:

- classification of actual or estimated information;
- if estimated, appropriate justification provided;
- data source;
- methodology and assumptions adopted to prepare the information;
- any additional comments to support the basis of preparation.

Where estimates have been provided, CitiPower is currently considering the feasibility of improvement opportunities to allow actual information to be provided in the future.

BOP ID	Tab ID	Tab Name	Table and Rule Allocation	Estimated / Actual	Data Source	Why Estimated – Provide justification	Methodology	Assumptions	Additional Comments
BMCP3.1BOP1	3.1	Revenue	TABLE 3.1.1 - REVENUE GROUPING BY CHARGEABLE QUANTITY Revenue from Fixed Customer Charges [Standard Control Services] Revenue from Energy Delivery charges where time of use is not a determinant [Standard Control Services] Revenue from On-Peak Energy Delivery charges [Standard Control Services] Revenue from Shoulder period Energy Delivery Charges [Standard Control Services] Revenue from Off-Peak Energy Delivery charges [Standard Control Services] Revenue from controlled load customer charges [Standard Control Services] Revenue from unmetered supplies [Standard Control Services] Revenue from Contracted Maximum Demand charges [Standard Control Services] Revenue from Measured Maximum Demand charges [Standard Control Services] Revenue from metering charges [Standard Control Services] Revenue from connection charges [Standard Control Services] Revenue from public lighting charges [Standard Control Services] Revenue from other Sources [Standard Control Services] Total revenue by chargeable quantity [Standard Control Services] TABLE 3.1.2 REVENUE GROUPING BY CUSTOMER TYPE OR CLASS Revenue from residential Customers [Standard Control Services] Revenue from Non residential customers not on demand tariffs [Standard Control Services] Revenue from Non-residential low voltage demand tariff customers [Standard Control Services] Revenue from Non-residential high voltage demand tariff customers [Standard Control Services] Revenue from unmetered supplies [Standard Control Services] Revenue from Other Customers [Standard Control Services] Total revenue by customer class [Standard Control Services]	Actual	Revenue data was sourced from the SAS AHNP_O9500 billing table. This SAS table mirrors actual billing data from CIS Open Vision (CISOV).	N/A	Billing data was obtained from the SAS AHNP_O9500 billing table. As billing is based off actual NUOS the distribution revenue must then be recalculated using DUOS tariffs. Unmetered revenue is based on revenue collected for the network specific Unmetered tariff and the general purpose 'Unmetered' classification.	N/A	N/A
BMCP3.1BOP2	3.1	Revenue	TABLE 3.1.1 - REVENUE GROUPING BY CHARGEABLE QUANTITY Revenue from Fixed Customer Charges [Alternative Control Services] Revenue from Energy Delivery charges where time of use is not a determinant	Actual	Alternative Control Services revenue is derived from the annual regulatory reports which are originally sourced from SAP.	N/A	When retailers/customers request work to be done for Alternative Control Services activities a charge is created in either CIS-OV or SAP. These charges are then allocated to a range of specific general ledger accounts dedicated to collecting Alternative Control Services	Totals for ACS	N/A

			[Alternative Control Services] Revenue from On-Peak Energy Delivery charges [Alternative Control Services] Revenue from Shoulder period Energy Delivery Charges [Alternative Control Services] Revenue from Off-Peak Energy Delivery charges [Alternative Control Services] Revenue from controlled load customer charges [Alternative Control Services] Revenue from unmetered supplies [Alternative Control Services] Revenue from Contracted Maximum Demand charges [Alternative Control Services] Revenue from Measured Maximum Demand charges [Alternative Control Services] Revenue from metering charges [Alternative Control Services] Revenue from connection charges [Alternative Control Services] Revenue from public lighting charges [Alternative Control Services] Revenue from other Sources [Alternative Control Services] Total revenue by chargeable quantity [Alternative Control Services]				revenue to facilitate reporting in the Statutory Accounts and Regulatory Accounts/Regulatory Information Notice.		
BMCP3.1BOP3	3.1	Revenue	TABLE 3.1.2 REVENUE GROUPING BY CUSTOMER TYPE OR CLASS Revenue from residential Customers [Alternative Control Services] Revenue from Non residential customers not on demand tariffs [Alternative Control Services] Revenue from Non-residential low voltage demand tariff customers [Alternative Control Services] Revenue from Non-residential high voltage demand tariff customers [Alternative Control Services] Revenue from unmetered supplies [Alternative Control Services] Revenue from Other Customers [Alternative Control Services] Total revenue by customer class [Alternative Control Services]	Actual	Alternative Control Services revenue is derived from the annual regulatory reports which are originally sourced from SAP.	N/A	When retailers/customers request work to be done for Alternative Control Services activities a charge is created in either CIS-OV or SAP. These charges are then allocated to a range of specific general ledger accounts dedicated to collecting Alternative Control Services revenue to facilitate reporting in the Statutory Accounts and Regulatory Accounts/Regulatory Information Notice.	N/A	N/A
BMCP3.1BOP4	3.1	Revenue	TABLE 3.1.3 REVENUE (penalties) ALLOWED (deducted) THROUGH INCENTIVE SCHEMES EBSS [Standard Control Services] EBSS [Alternative Control Services]	Estimated	EBSS revenue is derived from a calculation with the following inputs and their sources: - 2016-20 EBSS allowances sourced from the AER 2016-20 determination post tax revenue model (PTRM) published on the AER website - Inflation sourced from the Australian Bureau of Statistics index 6401.0 Tables 1 and 2 All Groups CPI; Australia	EBSS revenue is one of the building blocks used to calculate distribution tariffs. Revenue is not reported separately for each component of distribution tariffs in the business systems.	EBSS revenue allowances are set out in final determinations, smoothed over the relevant regulatory period. The smoothed revenue profile over the regulatory period recovers the NPV of the total revenue requirement (before smoothing) over the regulatory period. Therefore, each revenue requirement, including EBSS is smoothed over the regulatory period.	N/A	Essential Services Commission of Victoria (ESCV) efficiency carryover scheme revenues are also reported since the efficiency carryover scheme is the equivalent of the EBSS scheme. EBSS revenues are reported in the year the incentive has an impact on revenue rather the year of expenditure performance. Additionally, the EBSS carry over amounts have been smoothed over each regulatory period because prices were smoothed over regulatory periods.

									The requirements of the Notice have been met.
BMCP3.1BOP5	3.1	Revenue	TABLE 3.1.3 REVENUE (penalties) ALLOWED (deducted) THROUGH INCENTIVE SCHEMES STPIS [Standard Control Services] STPIS [Alternative Control Services]	Estimated	STPIS revenue is derived from a calculation with the following inputs and their sources: S factors for 2016 onwards are sourced from the AER approved annual pricing proposals, inflation sourced from the Australian Bureau of Statistics index 6401.0 Tables 1 and 2 All Groups CPI; Australia.	STPIS revenue is one component of distribution revenue. Each component of distribution revenue is not reported in the business systems. Therefore STPIS revenue must be derived.	STPIS is calculated as the product of the s-factor and adjusted annual smoothed revenue published in the AER approved annual pricing proposal	N/A	Alternative Control Services revenue for 2017 excludes an allocation of intercompany interest to maintain consistency with the 2011-2015 Regulatory Information Notice which does not include this revenue in this category. Alternative Control Services revenue for 2011-2015 is consistent with the Regulatory Information Notice. This therefore complies with the Reporting Requirements.
BMCP3.1BOP6	3.1	Revenue	TABLE 3.1.3 REVENUE (penalties) ALLOWED (deducted) THROUGH INCENTIVE SCHEMES F-Factor [Standard Control Services] F-Factor [Alternative Control Services]	Actual	F Factor revenue is derived from the AER approved annual pricing proposal models, which is the source for this revenue.	N/A	F Factor revenue is derived from the AER approved annual pricing proposal models. CitiPower is either rewarded or penalised for performing better or worse than their respective fire start targets.	N/A	CitiPower must report the penalties or rewards of incentive schemes in this table. The penalties or rewards from the schemes applied by previous jurisdictional regulators that are equivalent to the service target performance incentive scheme (STPIS) or efficiency benefit sharing scheme (EBSS) must be reported against the line items for those schemes. Revenues reported in Table 3.1.3 must reflect the effect on revenues of incentive schemes in the year that the penalty or reward is applied (as opposed to when it was earned which depending on the scheme may be in earlier years). For instance, if CitiPower is rewarded extra revenues for performance under the STPIS in 2009 and gains these revenues in 2011 these revenues must be reported in the 2011 year only.
BMCP3.1BOP7	3.1	Revenue	TABLE 3.1.3 REVENUE (penalties) ALLOWED (deducted) THROUGH INCENTIVE SCHEMES S-Factor True up [Standard Control Services] S-Factor True up [Alternative Control Services]	Estimated	2016-20 S factor close out revenue sourced from AER 2016-20 determination PTRM published on the AER website. WACC for 2016-20 sourced from AER 2016-20 determination PTRM published on the AER website. Inflation sourced from the Australian Bureau of Statistics index 6401.0 Tables 1 and 2 All Groups CPI, Australia.	Each component of distribution revenue is not reported in the business systems. S factor close out revenue earned.	S factor close out revenue is set out in the AER 2016-20 determination PTRM published on the AER website. Due to the smoothing in the PTRM of annual required revenue, the S factor close out revenue is smoothed over the regulatory period, along with the other building blocks.	N/A	Alternative Control Services revenue for 2017 excludes an allocation of intercompany interest to maintain consistency with the 2011-2015 Regulatory Information Notice which does not include this revenue in this category. CitiPower's approved CAM for 2011 and 2012 was inconsistent with the AER's final distribution determination 2011- 15 service classification. In December 2013 the AER approved an amended CAM which is consistent with the AER's final distribution determination 2011-15 service classification. For the purposes of this RIN, CitiPower has deemed that the 2011 and 2012 Regulatory Accounting Statements restated to be consistent with the approved amended CAM are the relevant Regulatory Accounting Statements. On this basis, revenue has been reported consistent with the cost allocation methodologies, Regulatory Financial Statements and revenue categories that applied in the relevant year. This therefore complies with the Reporting Requirements.
BMCP3.1BOP8	3.1	Revenue	TABLE 3.1.3 REVENUE (penalties) ALLOWED (deducted) THROUGH INCENTIVE SCHEMES Other [Standard Control Services] Other [Alternative Control Services]	Estimated	Total Shared asset adjustment is sourced from the 2016-20 AER 2016-20 determination PTRM published on the AER website. WACC for 2016-20 sourced from AER 2016-20 determination PTRM published on the AER website.	Shared asset revenue is one of the building blocks used to calculate distribution tariffs. Revenue is not reported separately for each component of distribution tariffs in the business systems.	Shared asset adjustment are included as 'Other'. Due to the smoothing in the PTRM of annual required revenue, the Shared asset adjustment is smoothed over the regulatory period, along with the other building blocks.	N/A	Essential Services Commission of Victoria (ESCV) efficiency carryover scheme revenues are also reported since the efficiency carryover scheme is the equivalent of the EBSS scheme. EBSS revenues are reported in the year the incentive has an impact on revenue rather the year of expenditure performance.

					Inflation sourced from the Australian Bureau of Statistics index 6401.0 Tables 1 and 2 All Groups CPI, Australia.				Additionally, the EBSS carry over amounts have been smoothed over each regulatory period because prices were smoothed over regulatory periods. The requirements of the Notice have been met.
BMCP3.2BOP1	3.2	Operating Expenditure	TABLE 3.2.1 Current opex categories and cost allocations	Actual	The data for the current opex categories and cost allocations 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 CitiPower.	N/A	The SAP financial system is used to extract the information required to state the DNSP opex information by category and regulatory segment. Using the audited statutory accounts for CitiPower, the business uses cost elements within SAP in order to disaggregate the data for the purposes of apportioning opex costs between opex categories and regulatory segments in accordance with the cost allocation methodology. Information presented in this table utilises the cost allocation methodology applicable for the most recent; year and presents the data in alignment with the current opex categories.	N/A	Opex has been reported consistent with the cost allocation methodology, Regulatory Financial Statements and current opex categories for the most recent year.
BMCP3.2BOP2	3.2	Operating Expenditure	TABLE 3.2.2 - Opex consistency - current cost allocation approach Opex for network services [Standard Control Services] Opex for network services [Alternative Control Services]	Estimated	The data for the current opex categories and cost allocations 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 CitiPower. The data has been allocated between categories of distribution service in accordance with the cost allocation methodology that applied in the relevant regulatory year.	An estimate is required for opex for network services as this is a product of standard control total opex less the estimated amount calculated as opex for transmission connection point planning. As this estimated amount is deducted from the actual standard control opex, this therefore makes opex for network services an estimate. For the reasons why an estimate was required, relating to transmission connection point planning, please refer to DOPEX0206A Opex for transmission connection point planning.	The SAP financial system is used to extract the information required to state the DNSP opex information by category and regulatory segment. Using the audited statutory accounts for CitiPower, the business uses cost elements within SAP in order to disaggregate the data for the purposes of apportioning opex costs between opex categories and regulatory segments in accordance with the cost allocation methodology. Information presented in this table utilises the cost allocation methodology that applied in the relevant regulatory year. Opex for network services is the total of standard control total opex less the amount reported as opex for transmission connection point planning. The amount deducted for transmission connection point planning is an estimation. For the methodology and assumptions relating to transmission connection point planning please refer to DOPEX0206 Opex for transmission connection point planning.	N/A	Opex has been reported consistent with the cost allocation methodology, Regulatory Financial Statements and opex categories in place at the time for those regulatory years, with the exception of the 2011 and 2012 years. CitiPower's approved CAM for 2011 and 2012 was inconsistent with the AER's final distribution determination 2011- 15 service classification. In December 2013 the AER approved an amended CAM which is consistent with the AER's final distribution determination 2011-15 service classification. For the purposes of this RIN, CitiPower has deemed that the 2011 and 2012 Regulatory Accounting Statements restated to be consistent with the approved amended CAM are the relevant Regulatory Accounting Statements. On this basis, opex has been reported consistent with the cost allocation methodologies, Regulatory Financial Statements and opex categories that applied in the relevant year.
BMCP3.2BOP3	3.2	Operating Expenditure	TABLE 3.2.2 - Opex consistency - current cost allocation approach Opex for metering [Standard Control Services] Opex for metering [Alternative Control Services] Opex for connection services [Standard Control Services] Opex for connection services [Alternative Control Services] Opex for public lighting [Standard Control Services] Opex for public lighting [Alternative Control Services] Opex for amounts payable for easement levy or similar direct charges on DNSP [Standard Control Services]	Actual	The data for the current opex categories and cost allocations 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 CitiPower. The data has been allocated between categories of distribution service in accordance with the cost allocation methodology that applied in the relevant regulatory year.	N/A	The SAP financial system is used to extract the information required to state the DNSP opex information by category and regulatory segment. Using the audited statutory accounts for CitiPower, the business uses cost elements within SAP in order to disaggregate the data for the purposes of apportioning opex costs between opex categories and regulatory segments in accordance with the cost allocation methodology. Information presented in this table utilises the cost allocation methodology that applied in the relevant regulatory year. Information has been reported as applicable to the categories listed and is a subset of total opex. Opex for connection services has been	N/A	CitiPower must report Opex in accordance with the categories that they reported in in response to their Annual Reporting Requirements. CitiPower must report Opex in accordance with our Variables and the Cost Allocation Approaches and reporting framework applied in the relevant Regulatory Years. Our Opex Variables are defined in chapter 9. CitiPower is required to report, for all Regulatory Years, Opex in accordance with the requirements of the Cost Allocation Approach and the Regulatory Accounting Statements that were in effect for the relevant Regulatory Year.

			Opex for amounts payable for easement levy or similar direct charges on DNSP [Alternative Control Services]				derived by applying connections RAB as a percentage of total SCS RAB as per template 3.3 over the current year's maintenance expenditure.		For the avoidance of doubt this means that: - The accounting principles applied by the NSP in completing its Regulatory Financial Statements for each individual Regulatory Year must be applied when reporting Opex for that Regulatory Year. - Opex reported must be prepared in a consistent manner to that of Opex reported in the Annual Reporting Requirements.
BMCP3.2BOP4	3.2	Operating Expenditure	TABLE 3.2.2 - Opex consistency - current cost allocation approach Opex for transmission connection point planning [Standard Control Services] Opex for transmission connection point planning [Alternative Control Services]	Estimated	The costs are prepared in an internal spreadsheet which is a summation of the following categories: The number of Terminal Stations, sourced from the annual Transmission Connection Planning Report (TCPR), percentage of average FTEs time spent per Connection Point on demand forecasting and directing augmentations, sourced from management judgement, Regulatory Test Report Legal Costs sourced from the SAP system, External consultant costs for the planning reports and economic studies.	A. Internal FTE costs for forecasting and directing augmentations: Basis used was management judgment to determine that each terminal station required 15% of the annual time of one engineering FTE, and each engineering FTE was estimated to be on a salary of $127.3k per year. B. The annual Consultant fee is an estimate based on management judgement of an approximate hourly rate charged by external consultants by the number of hours to complete the required reports. C. Internal FTE costs for preparing internal reports.	Each year is a summation of the categories listed in the source, and the methodology consists of: - The total internal FTE costs were based on the proportion of an FTE spent on each terminal station per year. The number of terminal station connections was an actual figure. - Legal costs were actual costs from invoices from external legal providers - Consultant fees for, Transmission Connection Planning Report (TCPR) Development, Internal Regulatory Test Reports, Joint Distribution Business Connection Planning were a combination of actual costs from invoices and management judgment of the split between areas. - Internal costs for preparing regulatory test reports were based on the proportion of an FTE spent on preparing the reports. - External consultants costs for published Regulatory Test Reports were actual costs from invoices.	TBA	CitiPower's approved CAM for 2011 and 2012 was inconsistent with the AER's final distribution determination 2011-15 service classification. In December 2013 the AER approved an amended CAM which is consistent with the AER's final distribution determination 2011-15 service classification. For the purposes of this RIN, CitiPower has deemed that the 2011 and 2012 Regulatory Accounting Statements restated to be consistent with the approved amended CAM are the relevant Regulatory Accounting Statements. On this basis, opex has been reported consistent with the cost allocation methodology and Regulatory Financial Statements that applied in the relevant regulatory year. Information has been reported as applicable to the categories listed and is a subset of total opex.
BMCP3.2BOP5	3.2	Operating Expenditure	TABLE 3.2.4 - OPEX FOR HIGH VOLTAGE CUSTOMERS Opex for high voltage customers [End user costs (not standard control services)]	Estimated	CP must report the amount of Opex that it would have incurred had it been responsible for operating and maintaining the electricity distribution transformers that are owned by its high voltage customers. - CPI data - sourced from finance. - CPI Maintenance costs - sourced from Function Code 350 and Function Code 318 expenditure as reported from BI. Definition of function codes as per Function Code Definitions Manual Document No 10-40-M0001. - Distribution transformer capacity owned by utility sourced from Network Planning also reported as DPA0501. - Distribution transformer capacity owned by High Voltage Customers sourced from Network Planning also reported as DPA0502	- HV customer capacity is not controlled by CitiPower and inherently is estimated. - The review and removal of costs not applicable to distribution substation maintenance from function codes 318 and 350 cannot be perfectly undertaken as general cost elements such as logistics expense and operational overheads such as works planning cannot be separated.	(i) Establish distribution transformer capacity owned by utility sourced from Network Planning (DPA0501) annual planning reports. (MVA) (ii) Establish total Distribution Substation Maintenance Opex from expenditure reports for Function Codes 350 and 318. (EN Distribution substation maintenance) ($k) Cost reports reviewed and costs not applicable to distribution substation maintenance removed. (iii) Calculate a nominal unit rate for Network Distribution Substation maintenance by dividing total MVA by total Opex to arrive at ($/MVA) (iv) Calculate a real unit rate by applying CPI to the rate calculate previously for years prior to current year (v) Average the real unit rates and set current year as the average, ($/MVA) (vi) Apply CPI to the average unit rate for years prior to current year, ($/MVA) (vii) Establish Distribution transformer capacity owned by High Voltage Customers sourced from Network Planning (DPA0502) annual planning reports. (MVA) (viii) Calculate HV Customer Opex for each year by multiplying Average unit rate by the Sum of the HV Customer Capacity, ($/MVA)	N/A	The response to the requirement DOPEX0401 is shown as estimated as CitiPower, by definition, cannot have actual data for costs it would have incurred if it had operating and maintenance responsibility for distribution transformers owned by HV customers. The estimation of DOPEX0401 has been carried out in accordance with the Requirements of the Notice instructions as above.

BMCP3.2.3BOP1	3.2.3	Provisions	TABLE 3.2.3 - PROVISIONS	Actual	The data for provisions 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 CitiPower.	NA	The SAP financial system is used to extract the information required to state the DNSP provision information. Using the audited statutory accounts for CitiPower, 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. 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 cost element mappings on financial data reported in the Annual Regulatory Accounting Statements as the allocator. (The Labour Cost-Matrix template) in the Regulatory Accounting Statements for this particular year is not representative of the labour mix and this work paper has been used as a substitute). The Long Service Leave Bond adjustment is allocated solely to opex and the remainder of the movement is split between opex and capex using this assumption.	N/A	Provisions have been reported consistent with that of the Regulatory Financial Statements for each regulatory year.
BMCP3.3BOP1	3.3	Assets (RAB)	TABLE 3.3.1 - REGULATORY ASSET BASE VALUES	Estimated	RIN data within tab	Source data is estimated	The data in this table is the sum of the RAB variables in Table 3.3.2.	N/A	N/A
BMCP3.3BOP2	3.3	Assets (RAB)	TABLE 3.3.2 - ASSET VALUE ROLL FORWARD	Estimated	- Data in this sheet - CPI from ABS table 6401.0 - Forecast depreciation from 2016-20 Final Determination PTRM - WACC from AER SCS PTRM updated for 2017 debt rate - Asset value data from 2013	The benchmarking RIN requires allocation into specific asset categories using specific AER methodology. This information is not available from existing business systems and data.	The RAB for Standard Control Services has been rolled forward using the AER roll forward model template and data from the sources listed. The allocation of regulatory asset categories to the required AER asset categories is based on the replacement cost methodology used in the 2013 Benchmarking RIN. This applies to the following regulatory asset categories: subtransmission, distribution system assets, VBRC, supervisory cables and old SWER ACRs. Other regulatory asset categories are allocated to the required AER asset categories either directly (eg. metering) or based on asset life. Disposals are taken as the cash proceeds from sale of assets as reported in the cash flow section of annual RIN.	N/A	This BOP covers data in the 'Standard Control Services' column.
BMCP3.3BOP3	3.3	Assets (RAB)	TABLE 3.3.2 - ASSET VALUE ROLL FORWARD	Estimated	- RIN data within tab - Estimated gross Dedicated Assets/Gross Connection capex ratio	As per AER requirements	The Network Services RAB has been estimated. An estimate of gross dedicated capex to gross new customer connection capex is used to estimate the proportion of net dedicated assets capex to net network capex. This ratio (averaged over 5 years) is used to estimate the connection services portion of the RAB which is deducted from SCS network RAB to derive the estimated Network Services	N/A	This BOP covers data in the 'Network Services' column.

							RAB.		
BMCP3.3BOP4	3.3	Assets (RAB)	TABLE 3.3.3 - TOTAL DISAGGREGATED RAB ASSET VALUES	Estimated	N/A	N/A	Total disaggregated RAB asset values have been calculated as the average of the opening and closing RAB values for each category, consistent with the AER's standard approach, detailed in 'Economic benchmarking RIN for distribution network service providers - Instructions and Definitions'. According to 'Economic benchmarking RIN for distribution network service providers - Instructions and Definitions' the RAB reported in this tab must include capital contributions. The capex reported in this tab is net capex and only net capex is rolled into the RAB, therefore capital contributions are not reported here.	N/A	N/A
BMCP3.3BOP5	3.3	Assets (RAB)	TABLE 3.3.4 - ASSET LIVES ESTIMATED SERVICE LIFE OF NEW ASSETS	Estimated	- 2016-20 Final Determination PTRM (Standard Control Services) - 2016-20 Final Determination PTRM (Metering) - 2016-20 Final Determination Public Lighting model - RIN data within tab	As per AER requirements	The asset lives are taken from the 2016-20 Final Determination models and the weighted average calculated for each of the required AER asset categories.	N/A	N/A
BMCP3.3BOP6	3.3	Assets (RAB)	TABLE 3.3.4 - ASSET LIVES ESTIMATED RESIDUAL SERVICE LIFE	Estimated	RIN data within tab	As per AER requirements	Remaining lives for all asset categories are calculated as the ratio of opening RAB to straight line depreciation.	N/A	
BMCP3.3BOP7	3.3	Assets (RAB)	TABLE 3.3.2 - ASSET VALUE ROLL FORWARD	Estimated	- Annual RIN data - CPI from ABS table 6401.0 - WACC from AER Metering PTRM updated for 2017 debt rate	N/A	The Metering RAB has been rolled forward using the AER roll forward model template and the data sources listed. The Public Lighting RAB has been rolled forward using the Final Determination Public Lighting model and the data sources listed. Capex for 'Energy Efficient' public lighting capex was taken directly from the Annual RIN. Capex for 'Non-Energy Efficient' public lighting has been allocated to 'Poles and brackets' and 'Existing Lights' based on the weightings of these in 2014. The capital expenditure includes public lighting replacements which do not incur customer contributions.	N/A	This BOP covers data in the 'Alternative Control Services' column in Table 3.3.2. The business has used the AER's standard approach provided under Economic Benchmarking RIN for distribution network service providers - Instructions and Definitions.
BMCP3.4BOP1	3.4	Operational Data	TABLE 3.4.1 - ENERGY DELIVERY Energy Delivery where time of use is not a determinant [Standard Control Services] Energy Delivery at On-peak times [Standard Control Services] Energy Delivery at Shoulder times [Standard Control Services] Energy Delivery at Off-peak times [Standard Control Services] Controlled load energy deliveries [Standard Control Services] Energy Delivery to unmetered supplies [Standard Control Services] Residential customers energy deliveries [Standard Control Services] Non residential customers not on demand tariffs energy deliveries	Actual	Energy volume data was sourced from the SAS AHNP_O9500 billing table. This table includes volumes as well as billed amounts. This SAS table mirrors actual billing data from CIS Open Vision (CISOV)	NA	Energy Volumes are based on billed volumes only relating to the year under review. Billing relating to other periods was excluded. Quantities were obtained by dividing revenue by the published NUOS price for each tariff. This approach accounts for pro-rating where customers may have only been billed for part of a month. Unmetered was addressed separately and a 60%/40% peak/off-peak split was assumed. Volumes were back-solved using known billings and published tariffs to determine quantities.	N/A	3.4 - The data for this table was obtained from billed energy volumes, accruals and any billing adjustments for that given year. Billed energy volumes, accruals and billing adjustments is calculated at site (NMI) level and aggregated as a total. 3.4.1.1 - As per the definitions under 'Charges' in chapter 9 of the Economic benchmarking RIN for DNSP, data recorded in this table is by tariff and reported in the benchmarking RIN by the definitions provided. Energy volumes reported under single rate tariffs was used to populate DOPED0201 where 'Energy Delivery where time of use is not a determinant'. 3.4.1.4 - As per the definitions under 'Customer Types' in chapter 9 of the Economic benchmarking RIN for DNSP, data recorded in this table is aggregated based on the

			[Standard Control Services] Non-residential low voltage demand tariff customers energy deliveries [Standard Control Services] Non-residential high voltage demand tariff customers energy deliveries [Standard Control Services] Other Customer Class Energy Deliveries [Standard Control Services]						definitions provide
BMCP3.4BOP2	3.4	Operational Data	TABLE 3.4.1 - ENERGY DELIVERY Energy into DNSP network at On-peak times [Standard Control Services] Energy into DNSP network at Shoulder times [Standard Control Services] Energy into DNSP network at Off-peak times [Standard Control Services] Energy received from TNSP and other DNSPs not included in the above categories [Standard Control Services]	Actual	The data has been sourced from the Itron Enterprise Edition (IEE) revenue metering system in some cases via the SAP HANA reporting tools. The IEE system contains all metering data for all meters from 2006 onwards. It has replaced metering systems previously used as the source of data in reporting energy figures. There may be differences in metering figures for past years compared to previously reported.	N/A	Data was extracted from the CitiPower IEE revenue metering system into MS Excel. A macro was then run to convert the interval data into Peak and Off Peak using the rule that Peak is 7am - 11pm on weekdays, and all other times are Off Peak. Shoulder times have not been considered in this modelling as it would create an inconsistency with the energy figures provided in DOPED0401 - DOPED0404 where it is not possible to perform that split.	N/A	CitiPower has reported energy received from Non-residential and residential Embedded Generation by time of receipt. Energy received from TNSP and other DNSP has been measured/calculated in accordance with the definitions of chapter 9, as meter data has been reported, not the accounts payable data for energy received.
BMCP3.4BOP3	3.4	Operational Data	TABLE 3.4.1 - ENERGY DELIVERY Energy into DNSP network at On-peak times from non-residential embedded generation [Standard Control Services] Energy into DNSP network at Shoulder times from non-residential embedded generation [Standard Control Services] Energy into DNSP network at Off-peak times from non-residential embedded generation [Standard Control Services] Energy received from embedded generation not included in above categories from non-residential embedded generation [Standard Control Services]	Actual	The data has been sourced from the Itron Enterprise Edition (IEE) revenue metering system (in some cases via the SAP HANA reporting tools). Data to break up customers into Residential and Non-Residential has come from CIS, where the flag Domestic has been used to assume a customer is Residential. All other customers have been treated as Non-Residential.	N/A	Generators from their interval data using Peak and Off Peak using the rule that Peak is 7am - 11pm on weekdays, and all other times are Off Peak.	N/A	CitiPower has reported energy received from Non-residential and residential Embedded Generation by time of receipt. Energy received from embedded generators has been measured/calculated in accordance with the definitions of chapter 9, as meter data has been reported, for energy received.
BMCP3.4BOP4	3.4	Operational Data	TABLE 3.4.2 - CUSTOMER NUMBERS Residential customer numbers [Standard Control Services] Non residential customers not on demand tariff customer numbers [Standard Control Services] Low voltage demand tariff customer numbers [Standard Control Services] High voltage demand tariff customer numbers [Standard Control Services] Unmetered Customer Numbers [Standard Control Services] Other Customer Numbers [Standard Control Services] Total customer numbers [Standard Control Services] Customers on CBD network [Standard Control Services] Customers on Urban network [Standard Control Services] Customers on Short rural network [Standard Control Services] Customers on Long rural network [Standard Control Services] Total customer numbers [Standard	Actual	Total customer numbers are obtained from CitiPower's billing system, CIS Open Vision.	N/A	Customer Numbers by customer type or class - The number of active (customer is not end-dated) NMIs per tariff is obtained from CitiPower's end of month reporting. For de-energised sites, a count is obtained of the last tariff that applied to all other sites, excluding abolished (extinct) sites. The active and de-energised numbers are added together to give Total Customer numbers, which are aggregated by grouping tariffs in accordance with the reporting categories. An average of these numbers at the start and end of the Regulatory Year is used. CISOV is the original source of all data. Customer Numbers by location on the network - Is calculated by weighting the Customer Numbers by customer type or class by split based on location. The proportions were calculated using GIS data in SAS with each NMI mapped to a feeder classified as either; CBD, Urban, Rural Long or Short.	N/A	3.4.2.1 - The customer numbers in this table is the count of energised and de-energised NMIs and categorised in accordance to the definitions stated under 'Customer Types' in chapter 9. 3.4.2.2 - The numbers reported in this table is the count of energised and de-energised NMIs in accordance to the definitions stated in chapter 9.

			Control Services]						
BMCP3.4BOP5	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Non-coincident Summated Raw System Annual Maximum Demand [Standard Control Services] Coincident Raw System Annual Maximum Demand [Standard Control Services] Non-coincident Summated Raw System Annual Maximum Demand [Standard Control Services] Coincident Raw System Annual Maximum Demand [Standard Control Services]	Actual	All zone substation raw peak demand source data is collected from Ion power quality meters, located at each individual zone substation. If Ion meter data is unavailable, then TrendScada data is used. Historically, CitiPower does not record coincident peak demand at the zone substation level. Where information has been previously reported to regulatory bodies, CitiPower has used this data for the benchmarking RIN. DOPSD0101 & DOPSD0201: Non-coincident summated Raw System Annual Maximum Demand	N/A	Each year contains the summation of all CitiPower Zone Substations MW and MVA load at coincident and non-coincident peak demand.	N/A	The information provided in tables 3.4.3.1 and 3.4.3.3 is a summation of the maximum demand measured at the zone substation for the non-coincident level and a summation of the zone substation demand measured at the time of peak demand of the whole CitiPower network (coincident). The measured maximum demand complies with the definition in chapter 10 of the National Electricity Rules, version 60. Note: The raw (or unadjusted) non coincident maximum demand at the zone substation level was annually reported from 2006 to 2012 in the Distribution System Planning Report (DSPR) and from 2012 onwards in the Distribution Annual Planning Report (DAPR).
BMCP3.4BOP6	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services]	Actual	All zone substation raw peak demand source data is collected from Ion power quality meters, located at each individual zone substation. If Ion meter data is unavailable, then TrendScada data is used. Historically, CitiPower does not report coincident peak demand at the zone substation level as it is not a regulatory requirement. Where information has been previously reported to regulatory bodies, CitiPower has used this data for the benchmarking RIN.DOPSD0102, DOPSD0103, DOPSD0202, DOPSD0203: Non coincident	To provide a coincident weather adjusted value, the ratio of the weather adjusted and raw non coincident peak demand was used.	Non coincident: a summation of all CitiPower Zone Substations. The raw ZSS MDs are temperature corrected to a 50% and 10% POE value using the average temperatures that occurred on the day of the MD. Coincident raw: is a summation of all CitiPower Zone Substations. Coincident 50% POE was calculated my multiplying the raw coincident by the ratio non coincident 50POE and non-coincident raw. Coincident 10% POE was calculated by multiplying the raw coincident by the ratio non coincident 10POE and non-coincident raw.	N/A	Historically CitiPower did not weather adjust its raw coincident maximum demand at zone substation level, only the non-coincident data was weather corrected to 50% POE. The coincident 50% POE data is a summation of the coincident maximum demand at the zone substation and weather correcting that using CitiPower's POE calculator. All 'actual' data provided in the previous EDPR was raw maximum demand as defined in chapter 10 of the National Electricity Rules. To provide an estimate for the historical 10% POE weather adjusted data, CitiPower used a ratio derived by the National Institute of Economic and Industry Research (NIEIR) and applied it to the summation of the non-coincident and coincident maximum demand at zone substation level. From 2011-2016 a ratio of the summated Terminal Station non coincident and coincident weather corrected data was used.
BMCP3.4BOP7	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Non-coincident Summated Raw System Annual Maximum Demand [Standard Control Services] Coincident Raw System Annual Maximum Demand [Standard Control Services] Non-coincident Summated Raw System Annual Maximum Demand [Standard Control Services] Coincident Raw System Annual Maximum Demand [Standard Control Services]	Actual	All Terminal station raw peak demand source data is collected from the IEE wholesale meter data for each individual Terminal Station.	NA	DOPSD0107 & DOPSD0207: Non-coincident summated raw system annual peak demand - The source data was obtained from the summation of the actual raw terminal station maximum demands for each year sourced from IEE database. DOPSD0110 & DOPSD0210: Coincident summated raw system annual peak demand - The source data was obtained from the summation of the actual raw terminal station maximum demands at the date and time of system peak for each year and sourced from IEE database	N/A	The information provided in the variable codes stated above in tables 3.4.3.2 and 3.4.3.4 is a summation of the maximum demand measured at the transmission connection point for the non-coincident level and a summation of the transmission connection point demand measured at the time of peak demand of the whole CitiPower network (coincident). The measured maximum demand complies with the definition in chapter 10 of the National Electricity Rules, version 60. Note that the summated maximum demand at a transmission level usually occurs in summer.

							The source of the data is the IEE wholesale metering database accessed through a tool called SAP BW on HANA Production. This data is contained in a load estimate spreadsheet for each terminal station which contains historical actual data.		Seasonal summer is used for the purposes of the RIN, hence summer 2017 is considered between the months November 2016 to March 2017. The information provided is consistent with the requirements of the Notice.
BMCP3.4BOP8	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 10% POE [Standard Control Services] Coincident Weather Adjusted System Annual Maximum Demand 50% POE [Standard Control Services]	Estimated	All Terminal station raw peak demand source data is collected from the IEE whole sale meter data for each individual Terminal station.	CitiPower does not weather adjust the coincident terminal station connection point maximum demands. To estimate the 10 and 50% POE coincident values, a ratio of the summated raw actual coincident terminal station maximum demands to summated raw actual non-coincident terminal station maximum demands was used as a multiplier with the summated non-coincident terminal station demand.	The POE is the probability that the actual weather circumstances will be such that the actual Maximum Demand experienced will exceed the relevant maximum demand measure adjusted for weather correction. A 50% Probability of Exceedance means that the Maximum Demand measure adjusted for weather correction is expected to be exceeded fifty out of every one hundred years. DOPSD0109 & DOPSD0209: Non-coincident summated weather adjusted system annual peak demand 50% POE - The source data was obtained from the summation of the weather adjusted 50% terminal station non-coincident maximum demands for each year sourced from various CitiPower load estimate spreadsheets. An internal POE calculator was used to calculate these figures. DOPSD0108 & DOPSD0208: Non-coincident summated weather adjusted system annual peak demand 10% POE - The source data was obtained from summation of the weather adjusted 10 % terminal station non-coincident maximum demands for each year sourced from various CitiPower load estimate spreadsheets. An internal POE calculator was used to calculate these figures. DOPSD0112 & DOPSD0212: Coincident summated weather adjusted system annual peak demand 50% POE - The data was derived from the coincident raw maximum demand data by utilising 50% POE/actual ratios provided by the National Institute of Economic and Industry Research (NIEIR) for the whole CitiPower network load. DOPSD0111 & DOPSD0211: Coincident summated weather adjusted system annual peak demand 10% POE - The data was derived from the coincident raw maximum demand data by utilising 10% POE/actual ratios provided by the National Institute of Economic and Industry Research (NIEIR) for the whole CitiPower network load. To estimate the 10 and 50% POE coincident values, a ratio of the summated raw actual coincident terminal station maximum demands to summated raw actual non-coincident terminal station maximum	N/A	The information provided in the variable codes stated above in tables 3.4.3.2 and 3.4.3.4 is a summation of the calculated or derived weather adjusted maximum demand measured at the transmission connection point for the non-coincident level and a summation of calculated or derived weather adjusted maximum demand at the transmission connection point demand measured at the time of peak demand of the whole CitiPower network (coincident). The measured maximum demand complies with the definition in chapter 10 of the National Electricity Rules, version 60. The information provided is consistent with the requirements of the Notice. Where estimated historical weather adjusted data is provided, CitiPower used a ratio derived by the National Institute of Economic and Industry Research (NIEIR) and applied it to the summation of the non-coincident and coincident maximum demand at the transmission connection point to provide the 10% POE (Probability of Exceedance) Level data.

							demands was used as a multiplier with the summated non-coincident terminal station demand.		
BMCP3.4BOP9	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Average overall network power factor conversion between MVA and MW [Standard Control Services] Average power factor conversion for low voltage distribution lines [Standard Control Services] Average power factor conversion for 3.3 kV lines [Standard Control Services] Average power factor conversion for 6.6 kV lines [Standard Control Services] Average power factor conversion for 7.6 kV lines [Standard Control Services] Average power factor conversion for 11 kV lines [Standard Control Services] Average power factor conversion for SWER lines [Standard Control Services] Average power factor conversion for 22 kV lines [Standard Control Services] Average power factor conversion for 33 kV lines [Standard Control Services] Average power factor conversion for 44 kV lines [Standard Control Services] Average power factor conversion for 66 kV lines [Standard Control Services] Average power factor conversion for 110 kV lines [Standard Control Services] Average power factor conversion for 132 kV lines [Standard Control Services] Average power factor conversion for 220 kV lines [Standard Control Services]	Estimated	DOPSD0301: Data used to calculate the power factor was sourced from DOPSD0110 and DOPSD0210. DOPSD0302, DOPSD0306, DOPSD0308, DOPSD0311, DOPSD0304: The data used to populate the above sections was sourced from Table 2, of section 4.3 of the 'Electricity Distribution Code' version 7 May 2012. The values used were for customer maximum demand over 2MVA, minimum lagging. DOPSD0303, DOPSD0305, DOPSD0307, DOPSD0309, DOPSD0310, DOPSD0312, DOPSD0313, DOPSD0314: CitiPower do not have these voltage lines and so are	The values defined in Table 2, of section 4.3 of the Electricity Distribution Code, version 7, May 2012, are standard reference values which are readily available for industry to use for any calculations where the power factor is required.	DOPSD301: Overall network power factor is calculated by dividing the transmission connection point coincident Raw system annual maximum demand MW by the terminal station coincident Raw system annual maximum demand MVA. DOPSD0302, DOPSD0304, DOPSD0306, DOPSD0308, DOPSD0311: Values taken from Table 2 of section 4.3 of the 'Electricity Distribution Code' The values used were for customer maximum demand over 2MVA, minimum lagging. This is the best engineering estimates as the data is not readily stored or available at these voltage levels.	N/A	Data used to calculate the average overall network power factor was sourced from the measured transmission connection point data in sections DOPSD0110 and DOPSD0210. As the data for the remaining voltage levels is not readily stored or available, as best engineering estimates, CitiPower refers to the values defined in Table 2, of section 4.3 of the 'Electricity Distribution Code' version 7, May 2012.
BMCP3.4BOP10	3.4	Operational Data	TABLE 3.4.3 - SYSTEM DEMAND Summated Chargeable Contracted Maximum Demand [Standard Control Services] Summated Chargeable Measured Maximum Demand [Standard Control Services] Summated Chargeable Contracted Maximum Demand [Standard Control Services] Summated Chargeable Measured Maximum Demand [Standard Control Services]	Actual	Similarly to the Energy Volumes data - summated demand was sourced from the SAS AHNP_O9500 billing table. This table includes volumes as well as billed amounts. This SAS table mirrors actual billing data from CIS Open Vision (CISOV)	NA	Summated quantities are aggregated by month (in line with billing) and the maximum quantity recorded within a given year is populated in the benchmarking RIN.	N/A	CitiPower's tariff structure charges demand on a unit of measure of kW. To comply with the definition of 'MW measure', the quantity is converted to MW. Customers are not charged on a MVA basis therefore the variable codes DOPSD0403 and DOPSD0404 have not been reported' to explain why these are zero.
BMCP3.5BOP1	3.5	Physical Assets	TABLE 3.5.1 - NETWORK CAPACITIES Overhead low voltage distribution [Volume in KM's (0's)] (DPA0101) Overhead 2.2 kV [Volume in KM's (0's)] (DPA0102) Overhead 6.6kv [Volume in KM's (0's)] (DPA0103) Overhead 7.6 kV [Volume in KM's (0's)] (DPA0104) Overhead 11 kV [Volume in KM's (0's)] (DPA0105) Overhead SWER [Volume in KM's (0's)] (DPA0106) Overhead 22 kV [Volume in KM's (0's)]	Actual	GIS is the originating data source. The data from GIS is made available to CitiPower through a BI (Business Intelligence) report called the 'Asset Installation Report'.	NA	The data was obtained utilising a GIS (Geographical Information System) query that traces the In-Service network connectivity model in GIS, to determine the circuit line length, which includes all spurs. Each circuit element was evaluated in its own right, for example: - SWER lines, single-phase lines, and three-phase lines counted as one line - Double circuit lines counted as two lines Note: - Although this methodology does not use the suggested Route Length methodology it does	N/A	For the year 2017 the data was obtained utilising a GIS (Geographical Information System) query that traces the in- service network connectivity model in GIS, to determine the circuit line length, which includes all spurs. Each circuit element was evaluated in its own right, for example: - SWER lines, single-phase lines, and three-phase lines counted as one line - Double circuit lines counted as two lines Note: Although this methodology does not use the suggested Route Length methodology it does deliver the network circuit length using the

			(DPA0107) Overhead 33 kV [Volume in KM's (0's)] (DPA0108) Overhead 44 kV [Volume in KM's (0's)] (DPA0109) Overhead 66 kV [Volume in KM's (0's)] (DPA0110) Overhead 110kV [Volume in KM's (0's)] (DPA0111) Overhead 132 kV [Volume in KM's (0's)] (DPA0112) Overhead 220kV [Volume in KM's (0's)] (DPA0113) Other [Volume in KM's (0's)] (DPA0114) Total overhead circuit km [Volume in KM's (0's)] (DPA01)				deliver the network circuit length using the criteria specified in this Information Notice - An overhead 22kV Subtransmission component was included as an additional line item for completeness - Overhead elements associated with communication, protection & control and unmetered loads were excluded In 2017 the data from GIS is made available through a BI (Business Intelligence) report called the 'Asset Installation Report'.		criteria specified in this Information Notice - An overhead 22kV Subtransmission component was included as an additional line item for completeness - Overhead elements associated with communication, protection & control and unmetered loads were excluded
BMCP3.5BOP2	3.5	Physical Assets	TABLE 3.5.1 - NETWORK CAPACITIES Underground low voltage distribution [Volume in KM's (0's)] (DPA0201) Underground 5 kV [Volume in KM's (0's)] (DPA0202) Underground 6.6 Kv [Volume in KM's (0's)] (DPA0203) Underground 7.6 kV [Volume in KM's (0's)] (DPA0204) Underground 11 kV [Volume in KM's (0's)] (DPA0205) Underground SWER [Volume in KM's (0's)] (DPA0206) Underground 22 kV [Volume in KM's (0's)] (DPA0207) Underground 33 kV [Volume in KM's (0's)] (DPA0208) Underground 66 kV [Volume in KM's (0's)] (DPA0209) Underground 110 kV [Volume in KM's (0's)] (DPA0210) Underground 132 kV [Volume in KM's (0's)] (DPA0211) Other [Volume in KM's (0's)] (DPA0212) Total underground circuit km [Volume in KM's (0's)] (DPA02)	Actual	GIS is the originating data source. The data from GIS is made available to CitiPower through a BI (Business Intelligence) report called the 'Asset Installation Report'.	N/A	The data from GIS is made available to through a BI (Business Intelligence) report called the Asset Installation Report.	N/A	For the year 2017 the data was obtained utilising a GIS (Geographical Information System) query that traces the in- service network connectivity model in GIS, to determine the circuit line length, which includes all spurs. Each circuit element was evaluated in its own right, for example: - SWER lines, single-phase lines, and three-phase lines counted as one line - Double circuit lines counted as two lines Note: - Although this methodology does not use the suggested Route Length methodology it does deliver the network circuit length using the criteria specified in this Information Notice An Underground 22kV Subtransmission component was included as an additional line item for completeness - Underground elements associated with communication, protection & control and unmetered loads were excluded
BMCP3.5BOP3	3.5	Physical Assets	TABLE 3.5.1 - NETWORK CAPACITIES Overhead low voltage distribution [Volume in MVA (0's)] (DPA0301) Overhead 6.6 kV [Volume in MVA (0's)] (DPA0302) Overhead 7.6 kV [Volume in MVA (0's)] (DPA0303) Overhead 11 kV [Volume in MVA (0's)] (DPA0304) Overhead SWER [Volume in MVA (0's)] (DPA0305) Overhead 22 kV [Volume in MVA (0's)] (DPA0306) Overhead 33 kV [Volume in MVA (0's)] (DPA0307) Overhead 44 kV [Volume in MVA (0's)] (DPA0308) Overhead 66 kV [Volume in MVA (0's)] (DPA0309)	Estimated	The data source for the estimated overhead and underground network weighted average MVA capacity come from estimates provided by the AER for the 66kV voltage and the network planning guidelines for all other voltages.	For the 66kV the estimation was provided by the AER, therefore applying this estimate ensures method calculation is in line with AER policy. For all other voltages, the network planning guidelines were used, as they are inline with how the network is operated.	The weighted average MVA capacity are estimates relating to the typical augmentation capacity constructed while allowing for planning policy. For example the 11 kV rating of 4MVA is the planning rating for new construction rated at 6MVA but allowing for transfers to adjacent feeders of 1/3 of capacity.	N/A	CitiPower has provided estimated overhead and underground weighted average capacity based on network planning guidelines for typical ratings per voltage class. The estimated data is in accordance with the definitions in chapter 9.

			Overhead 110 kV [Volume in MVA (0's)] (DPA0310) Overhead 132 kV [Volume in MVA (0's)] (DPA0311) Overhead 220 kV [Volume in MVA (0's)] (DPA0312) Other [Volume in MVA (0's)] (DPA0313) Underground low voltage distribution [Volume in MVA (0's)] (DPA0401) Underground 5 kV [Volume in MVA (0's)] (DPA0402) Underground 6.6 kV [Volume in MVA (0's)] (DPA0403) Underground 7.6 kV [Volume in MVA (0's)] (DPA0404) Underground 11 kV [Volume in MVA (0's)] (DPA0405) Underground SWER [Volume in MVA (0's)] (DPA0406) Underground 12.7 kV [Volume in MVA (0's)] (DPA0407) Underground 22 kV [Volume in MVA (0's)] (DPA0408) Underground 33 kV [Volume in MVA (0's)] (DPA0409) Underground 66 kV [Volume in MVA (0's)] (DPA0410) Underground 110 kV [Volume in MVA (0's)] (DPA0411) Underground 132 kV [Volume in MVA (0's)] (DPA0412) Other [Volume in MVA (0's)] (DPA0413)						
BMCP3.5BOP4	3.5	Physical Assets	TABLE 3.5.2 - TRANSFORMER CAPACITIES Distribution transformer capacity owned by utility [Volume in MVA's (0's)] (DPA0501)	Actual	The data was obtained utilising a GIS (Geographical Information System) query that determines the total In-Service distribution transformer metrics. The data from GIS is made available through a BI (Business Intelligence) report called the 'Asset Installation Report'.	N/A	GIS provides the data for a BI (Business Intelligence) report that provides the installed total distribution transformer MVA.	N/A	For the year 2017 the data was obtained utilising a GIS (Geographical Information System) query that traces via the in-service network connectivity model in GIS the distribution transformer connected
BMCP3.5BOP5	3.5	Physical Assets	TABLE 3.5.2 - TRANSFORMER CAPACITIES Distribution transformer capacity owned by High Voltage Customers [Volume in MVA's (0's)] (DPA0502)	Estimated	CIS O/V for HV Customer NMIs and SAP Hana for customer maximum demand data.	An estimate was required as there was no customer transformer MVA capacity data available. As CitiPower do not own the customer's transformer, the MVA capacity information is not required and has not been documented. The summation of customer maximum demand is used as an estimate of transformer capacity as proposed by the AER.	Report obtained from CIS O/V to determine which customers are on a HV tariff. From that list a SAP Hana report is run to sum the HV customer MD's (Used HV customer NMI's).	N/A	CitiPower has provided an estimated distribution transformer capacity owned by High Voltage Customers as a record of HV Customer installed capacity is not registered or maintained for accurate information to be recalled. The estimated data are in accordance with the definitions in chapter 9.
BMCP3.5BOP6	3.5	Physical Assets	TABLE 3.5.2 - TRANSFORMER CAPACITIES Cold spare capacity included in DPA0501 [Volume in MVA's (0's)] (DPA0503)	Actual	It is not current policy in CitiPower to operate the electricity distribution network with 'cold spare' distribution transformer capacity (in the form of actual transformers). However, it is policy to operate the electricity distribution network with a strategic level of spare distribution transformers held in store. A SAP inventory query was used to determine the year ending stock position for this metric.	N/A	A SAP inventory query was used to determine the year ending stock position for this metric	N/A	Electronic stores inventory records in SAP where accessed, queried and evaluated to determine the number and ratings of distribution transformers held in stock at the year ending for the reporting period as detailed in this Information Notice. The queries and evaluations excluded the number and capacity of all zone substation transformers, voltage transformers (potential transformers) and current transformers.
BMCP3.5BOP7	3.5	Physical	TABLE 3.5.2 - TRANSFORMER CAPACITIES	Actual	The data was obtained utilising:	NA	GIS provides the data for a BI (Business	N/A	For CitiPower this metric comprises the sum

		Assets	Total installed capacity for first step transformation where there are two steps to reach distribution voltage [Volume in MVA's (0's)] (DPA0601) Total installed capacity for second step transformation where there are two steps to reach distribution voltage [Volume in MVA's (0's)] (DPA0602) Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage [Volume in MVA's (0's)] (DPA0603) Total zone substation transformer capacity [Volume in MVA's (0's)] (DPA0604) Cold spare capacity of zone substation transformers included in DPA0604 [Volume in MVA's (0's)] (DPA0605)		- GIS (Geographical Information System) query that determines the total In-Service Zone Substation Transformer metrics. The data from GIS is made available through a BI (Business Intelligence) report called the 'Asset Installation Report'. - SAP - The Condition Based Reliability Maintenance (CBRM) System The 'Asset Installation Report' was used to determine this metric which was compared to the data in SAP and the CBRM database to provide the final data.		Intelligence) report that provides the installed Total Zone Substation Transformer MVA.		of two variables; the Total zone substation transformer capacity where there is only a single step of transformation to reach the distribution voltage (DPA 0603) and the cold spare capacity of zone substation transformers (DPA0605) as specified in this Information Notice, hence: DAP0601, 1st step of transformation = 0 as CitiPower do not have these DPA0602, 2nd step of transformation = 0 as CitiPower do not have these DPA0603, Single step of transformation to reach the distribution voltage = the reported value DPA0604 is the sum of DPA0601-0603 & DPA0605 DPA0605, Cold spare capacity = the reported value
BMCP3.5BOP8	3.5	Physical Assets	TABLE 3.5.3 - PUBLIC LIGHTING Public lighting luminaires [Volume (0's)] (DPA0701)	Actual	Based on the extract of billable lights extracted from GIS on the last day of the reportable year and provided in the Category Analysis RIN data template - 3.5. Physical Assets (DPA0701) Public Lighting Luminaires.	N/A	Source data was extracted from the GIS system into MS Excel listing all billable lights on the last day of the reportable year. All lights were multiplied by a 'k' factor (cost sharing) to ensure that luminaires were only counted once.	N/A	With regard to the Final RIN for Economic Benchmarking - Definitions and Instructions provided, 3.5.3 Public Lighting we have reported the number of public lighting luminaires and public lighting poles. We have provided numbers of assets owned by CitiPower and assets operated and maintained by CitiPower.
BMCP3.5BOP9	3.5	Physical Assets	TABLE 3.5.3 - PUBLIC LIGHTING Public lighting poles [Volume (0's)] (DPA0702)	Actual	Source data was obtained from GIS	N/A	Source data was extracted from GIS system into Excel listing all public lighting poles on the last day of the reportable year.	N/A	With regard to the Final RIN for Economic Benchmarking - Definitions and Instructions provided November 2013, 3.5.2 Public Lighting we have reported the number of public lighting poles. We have provided numbers of assets owned by CitiPower and assets operated and maintained by CitiPower. Only poles used exclusively to public lighting were counted.
BMCP3.6BOP1	3.6	Quality of Service	TABLE 3.6.1 - RELIABILITY Whole of network unplanned SAIDI [(0's)] Whole of network unplanned SAIDI excluding excluded outages [(0's)] Whole of network unplanned SAIFI [(0's)] Whole of network unplanned SAIFI excluding excluded outages [(0's)] Whole of network unplanned SAIDI [(0's)] Whole of network unplanned SAIDI excluding excluded outages [(0's)] Whole of network unplanned SAIFI [(0's)] Whole of network unplanned SAIFI excluding excluded outages [(0's)]	Actual	The source is the Annual Regulatory Performance Report and the AER Annual RINs The originating sources are Outage Management System & Business Intelligence and AER outage exclusions as per the AER STPIS Scheme dated November 2009	NA	The current STPIS scheme exclusion methodology and MED Threshold value were applied to the outage order history data to determine the - Inclusive of MED's data - Exclusive of MED's data	N/A	- The application of a single MED Threshold value as specified in this Information Notice together with the application of the current STPIS exclusion criteria to the historical data (2006 to 2013 inclusive) has been consistently applied, thereby standardising all the reporting for all the years with 2014. - This means that the 2010-2015 AER STPIS exclusion criteria has been applied to years 2006 to 2009 unplanned data to align the reporting to the current period - As a result of the above the metrics reported for 2006 to 2016 inclusive in this Benchmarking RIN may be different to those reported for those years in the Annual performance Reports and AER Annual RINs since: - the actual MED Thresholds applicable for years 2010 to 2012 inclusive used to determine these metrics in the annual reports are different to the single MED value as applied in this Information Notice - The exclusion criteria applicable for the

									years 2006 to 2009 inclusive used to determine these metrics in the annual reports are different to the exclusion criteria as applicable in this Information Notice
BMCP3.6BOP2	3.6	Quality of Service	TABLE 3.6.2 - ENERGY NOT SUPPLIED Energy Not Supplied (planned) [(0's)] Energy Not Supplied (unplanned) [(0's)] Total [(0's)]	Estimated	The originating outage data sources and reference documents were/are the - Outage Management System, Business Objects & Business Intelligence - Electricity distribution network service providers AER Service Target Performance Incentive Scheme (STPIS), November 2009, particularly section 3.3 Exclusions The annual network maximum demand, annual network energy consumption and feeder maximum demands were obtained from electrical energy meters.	Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions. The energy not supplied was determined using the fourth method utilising customer consumption estimated from the network maximum demand and the network energy consumed to derive a load factor. This load factor together with each feeder's specific customer numbers and maximum demand was used to estimate each feeder's energy consumption.	i. The planned energy component is the sum across all the feeders in the STPIS scheme ii. The unplanned energy component is the sum across all the feeders in the STPIS scheme iii. The total energy component is the sum of item i and item ii above For Methodology for CitiPower is as follows: - The network maximum demand and the network energy consumed to derive a load factor - This load factor together with each feeder's specific customer numbers and maximum demand is used to estimate each feeder's energy consumption - This estimate of each feeders consumption is used together with the planned & unplanned supply duration parameters exclusive of excluded outages as specified in this Information Notice to estimate the energy lost Calculations involved 1. Network Maximum Demand = (A) MW 2. Network Energy Delivered = (B) GWh 3. C = A*365*24 MWh 4. D = B*1000 MWh 5. Load Factor (LF) = C/D Energy Not Supplied at Feeder Level = {LF-(Feeder Maximum Demand*0.8)} X {(Feeder Minutes off Supply/60) / (Feeder Customer Numbers)}	N/A	The raw energy not supplied was determined using the fourth method (average feeder demand derived from feeder Maximum Demand and estimated load factor, divided by the number of customers on the feeder). utilising customer consumption estimated from the network maximum demand and the network energy consumed to derive a load factor. This load factor together with each feeder's specific customer numbers and maximum demand was used to estimate each feeder's energy consumption. This estimated consumption was applied to the planned and unplanned supply duration parameters exclusive of the excluded outages as specified in this Information Notice.
BMCP3.6BOP3	3.6	Quality of Service	TABLE 3.6.3 - SYSTEM LOSSES System losses [(0's)]	Actual	The source data to calculate annual year losses comprises of purchases data from the IEE database and sales data from CIS.	N/A	The data used was the purchases and sales for the regulatory year in question and then using formula; %Loss = (purchases - sales)/purchases * 100	N/A	The data is based on annual regulatory year losses from 2009 to 2016. Prior to 2009 financial year losses have been used as submitted to the AER as part of the annual Distribution Loss Factor submissions. CitiPower have used the financial year losses for 2006 - 2009 due to having not archived the source data therefore unable to spilt/ disclose the data by regulatory year.
BMCP3.6BOP4	3.6	Quality of Service	TABLE 3.6.4 - CAPACITY UTILISATION Overall utilisation [(0's)]	Actual	DQS04: Overall Utilisation Refer to the Non-coincident Summated Raw System Annual Peak Demand (DOPSD0201) and Total zone substation transformer capacity (DPA0604). The source of Non coincident Summated Raw System Annual Peak Demand (DOPSD0201) is obtained from TrendScada and ION meter data for CitiPower zone substations. Total zone substation transformer capacity (DPA0604) is a summation of DPA0601-0603. There is no installed capacity for DPA0601 & DPA0602. For DPA0603	N/A	Each year, the Non coincident Summated Raw System Annual Peak Demand (DOPSD0201) is divided by the Total zone substation transformer capacity (DPA0604). This value can only be calculated.	N/A	The capacity utilisation is calculated automatically in the table, where the measured non-coincident summated raw zone substation maximum demand (DOPSD0201) is divided by the summation of CitiPower Zone Substation transformer nameplate ratings (DPA0604). The summation of the nameplate ratings of the zone substations is reported annually in the annual RIN and is in accordance of the definitions in chapter 9.

BMCP3.7BOP1	3.7	Operating Environment	Table 3.7.1 - Density Factors	Estimated	The ratios are derived from variables found in the Benchmarking RIN. Refer to the relevant Basis of Preparation for the original source of these fields.	These variables are ratios and are therefore dependent upon whether the variable used in the ratio is an actual figure or an estimate. As at least one variable is an estimate, these ratios have been considered as an estimate as well.	Customer density (DOEF0101) - calculated by: 3.4.2.1 Total customer numbers (DOPCNO1) divided by 3.7.3 Route Line Length (DOEF0301) Energy Density (DOEF0102) - calculated by: 3.4.1 Total energy delivered (DOPED01) divided by 3.4.2.2 Total customer numbers by location (DOPCNO2) multiplied by 1000 Demand Density (DOEF0103) - calculated by: 3.4.3.3 Non-coincident Summated Raw System Annual MD (DOPSD0201) divided by 3.4.2.2 Total customer numbers by location (DOPCNO2) multiplied by 1000	N/A	The customer, energy and demand density were calculated using the variables as stipulated in the requirements of the notice.
BMCP3.7BOP2	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Rural Proportion [(0's)]	Estimated	The CitiPower distribution network comprises of categories that are either Central Business District (CBD) or Urban only. Hence the CitiPower distribution network has no (zero) Rural overhead or underground network.	N/A	No methodology or assumption are necessary.	N/A	The CitiPower distribution network comprises of categories that are either Central Business District (CBD) or Urban only. Hence the CitiPower distribution network has no (zero) Rural overhead or underground network section components. The reported rural proportion is therefore zero (0).
BMCP3.7BOP3	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Urban and CBD Vegetation Maintenance Spans [(0's)] Rural Vegetation Maintenance Spans [(0's)] Total Vegetation Maintenance Spans [(0's)] Total Number of Spans [(0's)]	Actual	The data base of reference for vegetation is found in SAP. SAP is also linked to our GIS data system where pole information and span link equipment number is sourced and transferred to SAP. The vegetation database records current status of vegetation spans for last inspection and last cut data. BI (Business Intelligence reporting tool) has been used to extract the data from SAP. Only active spans with cutting in the relevant year were considered for the report.	N/A	SAP stores all active spans on the network. Feeder class categories are extracted from SAP using BI reporting. The report is then used to filter using the relevant criteria e.g.: by Urban and Rural and then obtain a total of the two. Only spans with cutting notifications closed in the relevant year were considered for report.	N/A	CitiPower records vegetation against a span, so the count is as required by definition. The spans counted to report 'vegetation management spans' are those that are recorded as having had cutting of vegetation in the relevant year and so meets definition 'A span in CitiPower's network that is subject to active vegetation management practices in the relevant year. Active vegetation management practices do not include Inspection of vegetation Maintenance Spans'. The total number of spans is the count of active spans stored in SAP. Feeder categorisation for each year has been linked from relevant annual RIN data for the year therefore categorisation to Rural and Urban is compliant.
BMCP3.7BOP4	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Average Urban and CBD Vegetation Maintenance Span Cycle [(0's)] Average Rural Vegetation Maintenance Span Cycle [(0's)]	Actual	The data base of reference for vegetation is SAP, and VMS (Vegetation Management data base) which is linked to our GIS data system where pole information and span link equipment numbers are sourced. The reporting is extracted from our BI (Business Intelligence) system based on criteria relevant to our requirements.	N/A	Average frequency of cutting cycle (years) is based on the difference between two cutting cycles which lie in different years. A new Span is counted as 1 year for the relevant cutting year. The data was extracted from BI which is stored in SAP.	N/A	CitiPower records vegetation against a span, so the count is as required by definition. Feeder categorisation for each year has been linked from relevant annual RIN data for the year therefore categorisation to Rural and CBD/Urban is compliant. CitiPower does not have specific cycles for areas but rather the interval for pruning action is based on the particular circumstances of each span and the code allocated indicates the number of years before intervention is expected to be required. This can be more than once per year or periods greater than 5 years. To meet the AER definition we have interpreted area to be the span and have calculated the simple average for all spans in the Feeder classification areas therefore meeting the definition

									Average frequency of cutting cycle (years) is based on the difference between two cutting cycles which lie in different year. A new Span is counted as 1 year for the relevant cutting year. The data was extracted from BI reporting for the purpose of RIN data reporting
BMCP3.7BOP5	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Average Number of Trees per Urban and CBD Vegetation Maintenance Span [(0's)] Average Number of Trees per Rural Vegetation Maintenance Span [(0's)]	Actual	The data base of reference for vegetation is SAP, and VMS (Vegetation Management data base) which is linked to our GIS data system where pole information and span link equipment numbers are sourced. The reporting is extracted from our BI (Business Intelligence) system based on criteria relevant to our requirements.	N/A	Data for the average number of trees within CitiPower's Vegetation Maintenance Spans is based on cutting within the relevant year. This includes only trees that require active vegetation management to meet its vegetation management obligations. This excludes trees that only require Inspections and no other vegetation management activities required to comply with CitiPower's vegetation obligations./ The average number of trees = total number of trees, as extracted via BI report, divided by the total number of spans cut for the relevant year.	N/A	CitiPower records vegetation against a span, so the count is as required by definition. Feeder class categorisation for each year has been linked from relevant annual RIN data for the year therefore categorisation to Rural and CBD/Urban is compliant. The average number of trees per CitiPower maintenance spans is based on cutting completed within the relevant year. This includes trees that only require active vegetation management to meet its vegetation management obligations. This excludes trees that only require inspections and no other vegetation activity. The average number of trees = total number of trees, as extracted via BI report, divided by the total number of spans cut for the relevant year.
BMCP3.7BOP6	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Average Number of Defects per Urban and CBD Vegetation Maintenance Span [(0's)] Average Number of Defects per Rural Vegetation Maintenance Span [(0's)]	Actual	The data base of reference for vegetation is SAP, and VMS (Vegetation Management data base) which is linked to our GIS data system where pole information and span link equipment numbers are sourced. The reporting is extracted from our BI (Business Intelligence) system based on criteria relevant to our requirements. CitiPower records Defects on vegetation Maintenance Spans as one, regardless of the number of Defects on the span. Therefore average number of defects = total cut spans excluding duplicates	N/A	Methodology CitiPower records Defects on vegetation Maintenance Spans as one, regardless of the number of Defects on the span. Therefore average number of defects = total cut spans (excluding duplicate spans) divided by total spans cut (including duplicate spans).	N/A	CitiPower records vegetation against a span, so the count is as required by definition. CitiPower records Defects on vegetation Maintenance Span as one, regardless of the number of Defects on the span. Feeder categorisation for each year has been linked from relevant annual RIN data for the year therefore categorisation to Rural and CBD/Urban is compliant.
BMCP3.7BOP7	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Tropical Proportion [(0's)]	Actual	Reference to Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology Australian Climatic Zones map (based on temperature and humidity) was used to identify that there is no 'Tropical Proportion' of the CitiPower electricity distribution area as mapped in CitiPower's Geographical Information System (GIS).	NA/	Modelling methodology: The Australian Bureau of Meteorology Australian Climatic Zones map (based on temperature and humidity) was used to verify that there is no part of the CitiPower electricity distribution area as mapped in the CitiPower GIS that falls into a geographical region defined as Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology. The assumptions made were That the Hot Humid Summer and Warm Humid Summer regions defined have not changed since 2006, and therefore can be applied across all years from 2006.	N/A	There is no part of the CitiPower electricity distribution area that falls into a geographical region defined as Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology. Note: The AER has verified & approved that no part of the CitiPower distribution network falls into a geographical region defined as Tropical.
BMCP3.7BOP8	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Standard Vehicle Access [(0's)]	Actual	Although no actual data exists for accessibility of poles and spans by a standard vehicle in the case of CitiPower, it is accepted that all parts of the distribution network are accessible by a standard vehicle as defined under chapter	N/A	No estimation or derivation was needed as CitiPower only operates in urban and CBD areas, which are considered to have full vehicle access, hence no benchmark is required for this variable.	N/A	The data is derived from the local and engineering understanding that all parts of the CitiPower distribution network are accessible by a standard vehicle as defined under chapter 9.

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BMCP3.7BOP9	3.7	Operating Environment	Table 3.7.2 - Terrain Factors Bushfire risk [(0's)]	Actual	CitiPower has no spans that are in areas designated as high bushfire risk areas. This means that this metric for CitiPower is zero (0)	N/A	CitiPower has no spans in areas designated as high bushfire risk areas	N/A	For the year 2017 the data was obtained utilising a GIS (Geographical Information System) query that traces the in-service network connectivity model in GIS, to determine the circuit line length, which includes all spurs. Each circuit element was evaluated in its own right, for example: - SWER lines, single-phase lines, and three-phase lines counted as one line - Double circuit lines counted as two lines Note:- Although this methodology does not use the suggested Route Length methodology it does deliver the network circuit length using the criteria specified in this Information Notice - An overhead 22kV Subtransmission component was included as an additional line item for completeness - Overhead elements associated with communication, protection & control and unmetered loads were excluded - Overhead elements in the DNSP's area that are owned by another DNSP were excluded Each individual span in this query is coded as being in either a high or low bushfire fire area. Areas of high and low fire risk areas are reviewed and defined annually by the relevant authorities.
BMCP3.7BOP10	3.7	Operating Environment	Table 3.7.3 - Service Area Factors Route Line Length [(0's)]	Estimated	With respect to Overhead Conductors: GIS was the originating data source The overhead conductor Circuit Lengths and Route Lengths were both obtained from GIS With respect to Underground Cables: Only the underground cable circuit length was obtained from GIS.	No estimation or derivation was necessary for the overhead conductors An estimation was necessary for the underground cables as no data from GIS was available	Overhead Conductors: The Overhead Route Line Length data was obtained utilising a query that summates the total of the overhead span lengths in GIS, to determine the Route Line Length. - Spans less than or equal to 10 metres in length were excluded - Multiple circuit lines within spans were counted as one line Underground Cables: Data could not be obtained utilising a GIS query to determine the total Underground Route Line Length - Assumptions made to estimate the Underground Route Line Length were as follows: - For CitiPower CBD the ratio of underground route length to circuit length is 0.50 - For CitiPower Urban the ratio of underground route length to circuit length is 0.80	N/A	With respect to Overhead Conductors For the year 2017 the data was obtained utilising a GIS (Geographical Information System) query that summates the total of the overhead network span lengths, to determine the total Overhead Route Line Length. - Spans less than or equal to 10 metres in length were excluded - Multiple circuit lines within spans were counted as one line Note:- - The Overhead Route Line Length includes all spans of high and low voltage greater than 10 metres in length - Overhead elements associated with communication, protection & control and unmetered loads were excluded - Overhead elements in the DNSP's area that are owned by another DNSP were excluded With respect to Underground Cables For the year 2017 the data could not be obtained utilising a GIS (Geographical Information System) query that summates the total of the underground network section lengths to determine the total Underground Route Line Length, hence an estimate for this metric was used.