AusNet Electricity Services Pty Ltd

Economic Benchmarking

2019 Regulatory Year Basis of Preparation

Basis of Preparation

2019 Regulatory Year

1. Overview

This Basis of Preparation document supports the preparation and reporting of the 2019 Regulatory Year data presented in AusNet Electricity Services Pty Limited's ("AusNet Electricity Services" or "the Company") reports entitled '2019 AusNet Electricity Services Economic Benchmarking - Actual Information', '2019 AusNet Electricity Services Economic Benchmarking - Estimated Information', '2019 AusNet Electricity Services Economic Benchmarking - Consolidated Information' and 'Other Supporting Information' ("the Reports"). The Reports provide data solely for the use of the Australian Energy Regulator ("AER") to perform benchmarking activities under the AER's Better Regulation program.

The Reports have been prepared in accordance with the 'Regulatory Information Notice issued under Division 4 of Part 3 of the National Electricity (Victoria) Law' ("RIN") issued by the AER on 28 November 2013, the accompanying 'Economic Benchmarking RIN for distribution network service providers - Instructions and Definitions' issued by the AER and other authoritative pronouncements of the AER.

AusNet Electricity Services' 2019 Regulatory Year is the period 1 January 2019 to 31 December 2019 ("Regulatory Year"). Data included in the Reports has been provided for the 2019 Regulatory Year. All financial data is presented in Australian dollars and non-financial data is stated as per the measures specified in the Reports.

The ultimate Australian parent entity of the Company is AusNet Services Limited. The AusNet Services Limited Group **(The Group)** owns and operates 3 regulated networks – an electricity distribution network, a gas distribution network, an electricity transmission network and unregulated businesses. Employees of The Group work across the 3 regulated networks and there are shared costs, overheads and other corporate costs that cannot be directly allocated to a particular network or other business units. These costs are proportioned amongst The Group's 3 regulated networks, as well as the unregulated businesses, based on a monthly Activity Based Costing ("ABC") survey process. ABC Surveys are completed by all cost centre managers and are in accordance with AusNet Services' Cost Allocation Methodology ("CAM").

Materiality has been applied throughout the Reports and Basis of Preparation. Materiality is defined as information that if omitted, misstated or not disclosed has the potential, individually or collectively to influence the economic decisions of users.

The Reports require inputs to be allocated between Standard Control Services and Alternative Control Services.

Standard Control Services are defined in the National Electricity Rules ("NER"). For clarity, Standard Control Services capture services only available through the network (typically provided to all customers or a broad class of customers) recovered through general network tariffs.

Alternative Control Services are defined in the NER. By way of context, Alternative Control Services are intended to capture electricity distribution services provided at the request of, or for the benefit of, specific customers with regulatory oversight of prices. Alternative control services are electricity distribution services that are a direct control service but not a standard control service.

The AER's requirement, applicable to the current regulatory year, is to report all variables as Actual Information, unless a variable is expressly allowed to be reported as Estimated Information under the RIN guidelines. Interpretation of the AER's definition of Actual and Estimated information requires management judgments to be made as to the appropriate classification of information including:

- the extent to which the information is sourced from accounting or other records used in the normal course of business; and
- the degree of estimation involved and whether the information is materially dependent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation.

The methodologies, assumptions and judgments made by Management in respect of variables are described within the relevant sections of this Basis of Preparation.

Where estimated information has been presented, the circumstances and the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is AusNet Electricity Services' best estimate has also been set out below. Estimates are Management's best estimate based on the data available. Estimates will often not equal the related actual results and estimates have only been made for the purpose of disclosing the information required under the RIN. Considerations of the cost and efficiency of preparation as well as the reliability and accuracy of data available have been considered in determining the best methodology to determine the estimates.

'Actual Information' is defined as information materially dependent on information recorded in historical accounting records or other records used in the normal course of business, and whose presentation is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation. Any information or allocation which has been calculated via the ABC survey process is considered Actual Information, as this is in accordance with the AER approved CAM.

To the extent applicable, the information reported has been prepared in a manner consistent with the policies and methodologies applied in preparing the Annual Regulatory Accounts. Ausnet Electricity Services adopted the new accounting standard, *AASB16 – Leases* which broadly changes the treatment of operating leases. This accounting policy change was adopted from 1 April 2019 in the AusNet Electricity Services RINs and Regulatory Accounts. The adoption date is consistent with the AusNet Services Group Accounting Policy and also the assumptions in the 2022-2026 EDPR Proposal. The 2019 impact was an increase to Non-Network Capex of $38.2M and a decrease to Opex of $4.3M (SCS & ACS). There were no other changes in Accounting Policies during the Regulatory Year that had a material impact on the information presented.

The preparation methodologies and information sources adopted in the preparation of the Reports are set out below.

Contents

3.1 Revenue

Distribution Use of Systems Revenue (“Revenue”) is measured at the fair value of the consideration received or receivable, net of the amount of Goods and Services Tax (“GST”) payable to the taxation authority. Revenue is recognised as the services are rendered and is reported inclusive of incentive scheme penalties and rewards. Total Revenue is disaggregated by chargeable quantity and by customer class.

There have been no material changes to the accounting policies adopted by AusNet Electricity Services in relation to Revenue during the 2019 Regulatory Year in comparison to previous Regulatory Years reported.

Table 3.1.1 Revenue grouping by Chargeable Quantity

Revenue reported has been classified into the chargeable quantity which most closely reflects the basis upon which the revenue was charged to customers. Where it has been determined that Revenue cannot be allocated to the specified chargeable quantity classifications (in DREV0101 to DREV0112), Revenue has been reported against ‘Revenue from other Sources’ (DREV0113).

Preparation Methodology:

Standard Control:

Revenue by distribution tariff was sourced from the supporting documentation used to prepare the 2019 Annual Regulatory Accounts and allocated into the categories presented using Distribution Use of System (“DUOS”) tariff schedules.

Amounts included as ‘Revenue from other Sources’ relate to summer export payments made to customers for solar feed-in which forms part of DUOS Revenue reported in the 2019 Annual Regulatory Accounts.

Alternative Control:

Revenue was sourced from the supporting documentation used to prepare the 2019 Annual Regulatory Accounts and allocated into the categories presented.

Table 3.1.2 Revenue grouping by Customer Type or Class

Revenue reported has been classified into the Customer Type or Class which most closely reflects the customers from which revenue was charged. Where it has been determined that Revenue cannot be allocated to the specified Customer Type (in DREV0201 to DREV0205), Revenue has been reported against ‘Revenue from other Customers’ (DREV0206).

Preparation Methodology:

Standard Control:

Revenue reported in Standard Control Table 3.1.2 was allocated into customer type or class based on DUOS tariff schedules used to prepare the 2019 Annual Regulatory Accounts.

Alternative Control:

Revenue reported in Alternative Control Table 3.1.2 was allocated to 'Revenue from Other Customers' for all non-meter provision charges as the Revenue cannot be allocated to the specified chargeable quantity classifications in DREV0201 to DREV0205 based on the information available. Meter provision charges have been allocated based on the type of customer.

Table 3.1.3 Revenue (penalties) allowed (deducted) through incentive schemes

The penalties or rewards from the service target performance incentive scheme ("STPIS") or efficiency benefit sharing scheme ("EBSS") have been reported based on the year that the penalty or reward was applied, not the year in which it was earned. The penalties or rewards from the schemes applied by previous jurisdictional regulators that are equivalent to the STPIS or EBSS schemes have been reported against the applicable scheme category.

<u>Preparation Methodology</u>:

Information was sourced from 2019 Annual Regulatory Accounts, Annual Tariff Submissions & Post Tax Revenue Model.

EBSS:

EBSS revenue or penalties were calculated by smoothing the nominal EBSS allowance over the 5 year period from 2016 to 2020 based on the Smoothed Revenue profile in the 2016 to 2020 Post Tax Revenue Model. EBSS Revenue was collected in accordance with the allowances and penalties prescribed for the applicable 5 year Revenue determination period.

STPIS:

STPIS was calculated by dividing the total DUOS revenue by (1+ incentive scheme rate) and reporting the resultant difference between reported Revenue and this adjusted Revenue as STPIS. STPIS Revenue was collected in accordance with the incentive scheme rate prescribed by the AER for the applicable period.

S-Factor True Up:

A proportion of annual revenue has been attributed to the nominal S–Factor true up included in the 2016-2020 revenue requirement reflecting the close out of the previous S-Factor regime. To calculate the impact in each of the years, the total S-Factor true up over the five years was allocated to individual years based on the Smoothed Revenue profile in the 2016-2020 Post Tax Revenue Model. This approach most accurately reflects the years in which the revenue was generated.

F-Factor:

F-Factor revenue is recovered by AusNet Electricity Services via the addition of approved pass through tariffs to DUOS prices. The approved pass-through amount has been adjusted to reflect the difference between AusNet Electricity Services' 2019 Annual DUOS Revenue Target and the actual DUOS revenue received to determine the total amount of F-Factor revenue earned in 2019. This calculation is performed to take account of differences between forecast and actual volumes delivered.

Estimated Information:

All information reported is Actual Information. No estimates were required.

3.2 Operating Expenditure

Operating Expenses ("Opex") are the costs of operating and maintaining the network (excluding all capital costs and capital construction costs). Only those costs that are disclosed as Operating and Maintenance expenditure in the 2019 Annual Regulatory Accounts have been included in the Opex tables in Section 3.2. All other expenses have been excluded.

Opex that is incurred for a particular network within The Group is directly recorded to that network. Costs that cannot be directly allocated to a particular network within The Group are proportioned amongst The Group's 3 regulated networks as well as unregulated businesses via an ABC survey process. This is in accordance with AusNet Electricity Services' CAM.

AASB 16 Leases was made mandatory for adoption for all financial reports on or after 1 January 2019. Given the AusNet Services Group has a 31 March financial year end, this standard was adopted by the group on 1 April 2019. However, since the SPFRs are reporting a 1 January 2019 to 31 December 2019 year, the impact of AASB 16 must be rolled-back to 1 January 2019 for mandatory adoption date of AASB 16 to be complied with. The mandatory adoption dates refer to the preparation of financial reports complying with AASBs, but not to the preparation of the RIN templates. Consistent with our EDPR submission, the impact of AASB 16 is effective 1 April 2019 which aligns with our Group accounting adoption date.

This treatment is also consistent with Ausnet Electricity Services' proposed EDPR submission. As a result, Operating Leases which were previously treated as Opex are classified as capital in nature. In Table 3.2.2, the impact of the accounting standard change has been reversed and data is presented in a manner consistent with prior Regulatory Years.

Table 3.2.1 Opex Categories

Opex categories and allocations have been presented as per the categories in the 2019 Annual Regulatory Accounts and in accordance with requirements of the CAM and the Annual Reporting Requirements. Opex for Standard Control Services and Alternative Control Services agrees to operating expenses and maintenance as disclosed in the 2019 Annual Regulatory Accounts.

Preparation Methodology:

Using data extracted from the 2019 Annual Regulatory Accounts, sourced from the financial system, operating and maintenance expenses were allocated into the categories applicable for the 2019 Regulatory Year.

Estimated Information:

All information reported is Actual Information. No estimates were required.

Table 3.2.2 Opex Consistency

Preparation Methodology:

Data provided in Table 3.2.2 has been presented in a manner consistent with the presentation of Opex in prior periods.

In relation to Standard Control Services opex, data was extracted from the financial system and allocated into categories based on work codes and/or cost ledger codes. Each code was reviewed by a subject matter expert ("SME") and a relationship identified between the code and the regulatory category in Table 3.2.2.

In relation to Opex for Connection Services, the AER defined this reporting category as operating and maintaining costs for connection services that aren't capitalised. Amounts reported include SCS connection projects and indirect costs attributed to connection services.

In relation to Transmission Point Planning Opex, data reported was obtained via the ABC survey process and reflects the salary costs of the employees involved in transmission point planning scaled by the portion of their time spent undertaking such activities.

In relation to Alternative Control Opex, data was extracted from the 2019 Annual Regulatory Accounts and allocated into the categories applicable for the 2019 Regulatory Year.

For the purposes of economic benchmarking, Ausnet Electricity Services has added back in the impact of the adoption the new accounting standard AASB16 – Leases to ensure comparative benchmarking information, using variables 'DOPEX0201 Opex for network services' that reflects the SCS opex allocation and 'DOPEX0202 Opex for metering opex' allocation of the leases.

Estimated Information:

All information reported is Actual Information as no estimates were required, except for variables DOPEX0201 and DOPEX0202, where Ausnet Electricity Services used an estimated methodology. Ausnet Electricity Services calculated the CY18 percentage opex split between SCS and Metering leases and applied the same percentage to its existing leasing arrangements that are in place for CY19.

Table 3.2.4 Opex for high voltage customers

Opex for high voltage customers has been reported based on the amount of Opex that would have been incurred in maintaining the electricity distribution transformers which are owned by high voltage customers.

Preparation Methodology:

Actual Information is unavailable; therefore, an estimate has been derived based on the opex incurred for operating similar MVA capacity Distribution Transformers within the network. AusNet Electricity Services has high voltage customers who are supplied electricity at the higher voltage ratings of 6.6kV, 12kV and 22kV as well as sub transmission customers who are supplied electricity at 66kV.

The estimate has been calculated as the total cost of maintaining all owned transformers, divided by the number (units) of owned transformers. The resultant average cost is multiplied by the number of customers. This calculation relies on the assumption that 'Opex for High Voltage Customers' is in line with Opex incurred for similar activities by AusNet Electricity Services.

Estimated Information:

For customers who are supplied electricity at 6.6kV, 12kV and 22kV, average unit cost is derived based on AusNet Electricity Services' estimated cost to maintain high voltage distribution substations, apportioned based on the capacity and number of substations.

It should be noted that this is an estimate based on AusNet Electricity Services' estimated cost to maintain substations. It has been assumed that the cost of maintaining each type of substation (for example mounted substations, kiosk substations, ground type and indoor) is identical as maintenance costs are not available by substation type. It has also been assumed that the customer substations are similar in design to AusNet Electricity Services' substations. This is considered a reasonable assumption as substation designs across Victoria are generally similar.

As a licensed distribution company operating under an Electricity Safety Management Scheme (ESMS), AusNet Electricity Services has significant economies of scale. Therefore, a customer would spend more on average to maintain a substation. Hence, an additional calculation is performed to scale up the unit cost based on what a customer may be expected to pay to maintain a larger substation (e.g. 500kV). An average unit cost has then been applied to estimate the total opex associated with these customers.

Among the customers who are supplied electricity at 66kV, one is similar in size to that of a typical AusNet Electricity Services zone substation, and as such, the unit cost is estimated to be similar to AusNet Electricity Services' average opex cost for a typical zone substation. For the other 66kV customers that are lesser in size, their average opex cost is assumed to be half of that of a typical AusNet Electricity Services' zone substation – reflecting the reduction in the size of the substation and a reduction in the complexity of the associated maintenance costs.

Information was obtained from the financial system and the billing system. For consistency and comparability, information from the 2012 Regulatory Year was used as that was also the basis to estimate the data. In calculating the value for the current Regulatory Year, AusNet Electricity Services adjusted the 2012 base for customer numbers and applied a Consumer Price Index escalation factor to arrive at the current Regulatory Years value. This is considered Management's best estimate based on the data available. Based on the RIN Instructions and Definitions, this metric is permitted to be Estimated Information on an ongoing basis.

3.2.3 Provisions

Provisions are recognised when AusNet Electricity Services has a present legal or constructive obligation as a result of past events, it is more likely than not that an outflow of resources will be required to settle the obligation and the amount of the provision can be measured reliably. Provisions are not recognised for future operating losses.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at the relevant reporting date that considers the risks and uncertainties surrounding the obligations. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows.

Data presented has been reported in accordance with the requirements of the CAM and includes both Standard Control Services and Advanced Metering Infrastructure ("AMI").

Provisions have been separately presented based on the nature of the provision and allocated between an Opex component and a Capital Expenditure ("Capex") component based on the classification of the underlying cost associated with the provision.

Table 3.2.3 – Provisions

Preparation Methodology:

Provision - Uninsured Losses, Provision – Miscellaneous, Provision for Make Good and Provision – Other

Data was extracted from the financial system and, based on the nature of the Provision/transaction, mapped to the relevant category. Data was reviewed by an SME to ensure the Provision movements do not have any components related to non-SCS or AMI services.

Estimated Information:

All information reported is Actual Information. No estimates were required as the provision information was sourced from Ausnet Electricity Services' financial accounts

Preparation Methodology:

Provision - Superannuation and Provision - Employee Entitlements

The amounts reported in the 'Provision - Employee Entitlements' table relate to liabilities for wages and salaries, including non-monetary benefits and annual leave recognised in respect of employees' services up to the reporting date and are measured at the amounts expected to be paid when the liabilities are settled.

Data was extracted from the financial system and allocated into SCS and AMI using the percentage split of SCS, AMI and Alternative Control Services ("ACS") total operating and maintenance costs per the 2019 Annual Regulatory Accounts.

For Employee Entitlements Provision and Provision for Superannuation, the split between the opex component and the capex component was estimated. To determine the proportion of these provisions that should be classified as capex, the results from the monthly 2019 ABC surveys were applied.

Estimated Information:

The split between the opex component and the capex component of the Employee Entitlements Provision and Provision for Superannuation was estimated as the data is not separately captured in the financial system.

This is considered to be Management's best estimate based on the information available.

3.3 Assets (RAB)

The Regulated Asset Base ("RAB") values have been prepared and reported as per AusNet Electricity Services' interpretation of the AER instructions set out in Section 4 of the RIN Instructions and Definitions ("RIN I&Ds").

Opening RAB values have been sourced from the 2018 Economic Benchmarking RIN. Some further opening RAB adjustments for Standard Control Services were made to reflect the latest "Amended" regulatory determination for AusNet Services (2016-20), including approved contingent project (REFCL tranche 3). AusNet Services has also made cumulative corrections in the 2019 Public Lighting opening RAB value that forms part of Alternative Control Services.

The accounting policies adopted by AusNet Electricity Services in relation to capex (the only regulatory accounting input into the RAB) have not materially changed during the 2019 Regulatory Year compared to previous Regulatory Years reported.

Consistent with the 2018 RIN, we have reported the RAB roll forward for Meters in Alternative Control Services.

Table 3.3.1 Regulatory Asset Base Values

The RAB values have been prepared and reported as per AusNet Electricity Services' interpretation of the AER instructions set out in Section 4 of the RIN I&Ds.

Preparation Methodology:

The Opening RAB values were initially sourced from the 2018 Economic Benchmarking RIN.

Data on Actual Additions and Disposals have been reconciled to the 2019 Annual Regulatory Accounts supporting workpapers. For Actual Additions, under Standard Control and Network Services, values include a 6-month nominal WACC allowance consistent with the treatment of additions in the AER's Roll Forward Model. Actual Additions exclude the capital movement in provisions.

On 3 October 2019, the AER made a final decision on AusNet Services' contingent project application for tranche three of the REFCL installation program[1].

This revised determination increases allowed capital and operating expenditures for 2016-20 and, therefore increases the depreciation allowance for calendar years 2019-20. Of note for the RAB roll forward model calculation is an increased 'Equity Raising Costs' allowance ('benchmark' expenditure allowance) in 2016 - year 1 of the regulatory control period.

The 2019 opening RAB balances used in preparing the 2019 RIN therefore takes into account the net increase in equity raising costs (impacting 'Other assets with long lives' RIN category).

Straight-line depreciation (reported in DRAB0103), is based on forecast straight-line depreciation per the AER's Amended Final Decision 2016-20 PTRM model expressed in real 2015 dollars, adjusted for actual

[1] AER - AusNet Services distribution determination - 2019 debt update (including REFCL contingent project T3) - PTRM - 3 October 2019

inflation. The incremental straight-line depreciation allowance for calendar year 2019 (attributed to Tranche 3 capex) is -$0.06 million (real $2015).

Estimated Information:

AusNet Electricity Services considers that the proportion of the distribution assets that are dedicated connection assets is small. It has been assumed the customer contribution has more than fully funded customers' dedicated assets. Therefore, subject to the removal of metering and public lighting assets and equity raising costs, the capex included in the Standard Control Services and the Network Services Tables is equal. The data contained in Table 3.3.1 is considered actual. Information prepared at this highest level is sourced directly from the respective roll forward models without any estimation or allocation methods required.

Table 3.3.2 Asset value Roll forward

The disaggregated RAB values have been constructed as per AusNet Electricity Services' interpretation of the AER instructions set out in Section 4 of the RIN I&Ds.

AusNet Electricity Services has recorded assets in the RAB in asset classes that do not allow a direct attribution into the AER's economic benchmarking RAB Asset classes for the majority of assets.

Therefore, where direct attribution is not possible, AusNet Electricity Services has utilised the standard approach outlined Section 4.1.1 of the RIN I&Ds.

Preparation Methodology:

Information has been sourced from the 2018 Economic Benchmarking RIN, the AER's Amended 2016-20 Final Decision for AusNet Services (including REFCLs Tranches 1, 2 and 3), the AER's 2016-20 Final Decision for Metering PTRM & Exit Fees and supporting workpapers to the 2019 Annual Regulatory Accounts.

The following process was followed:

1. In accordance with RIN I&Ds, the 2019 opening RAB values were sourced from the 2018 Economic Benchmarking RIN data for standard control services, network services and alternative control services.
2. The 2019 Opening RAB values in Alternative Control Services were sourced from: -
    a. For Metering RAB, the opening value was sourced from the 2018 Economic Benchmarking RIN data.
    b. For Public Lighting RAB, the opening value was sourced from an Amended roll forward model containing net capex adjustments that were included in the 2021-26 Distribution revenue proposal for Public Lighting. These adjustments relate to corrections of prior year capex inputs including regulatory years 2015, 2016, and 2017. The overall change is a net increase in historical capex of $1,874,457 (real $2015). The Amended closing 2018 RAB value has accordingly increased by $2,181,190 ($Nominal) compared to the original 2018 Economic Benchmarking RIN data.

3. Split between Standard Control Services, Network Services, and Alternative Control Services:
    a. Network Services and Standard Control Services exclude public lighting and meters as instructed by the AER
    b. Alternative Control Services – this category includes metering and public lighting assets post 2005. Historical additions for metering RAB are net of Metering remediation costs which are not allowed to be recovered from customers.
4. Table 3.3.1 was directly disaggregated into the available RAB categories from the Roll Forward Model (column 1 in the table below):

Table RAB1

Roll Forward RAB categories	Benchmarking RIN categories
Distribution	Overhead network assets less than 33kV (wires and poles)
	Underground network assets less than 33kV (cables)
	Distribution substations including transformers
Sub-transmission	Overhead network assets 33kV and above (wires and towers / poles etc.)
	Underground network assets 33kV and above (cables, ducts etc.)
	Zone substations and transformers
Land	Zone substations and transformers
Non-network Leasehold Land & Buildings (SCS)	“Other” assets with long lives
Equity Raising Costs and SCADA assets	“Other” assets with long lives
Metering (ACS)	Meters
Non-network Leasehold Land & Buildings (Metering / AMI sites)	Meters
Public Lighting (ACS)	“Other” assets with long lives
Non-Network IT and Other	“Other” assets with short lives

Hence, additions and disposals were directly attributed into column 1 (above) categories, reconciling to the 2019 Annual Regulatory Accounts[2] and Straight-Line depreciation reconciled to forecast depreciation from the AER’s Amended 2016-20 Final Decision for AusNet Services (including REFCLs Tranches 1, 2 and 3).

The 2019 Opening RAB values are directly sourced from the 2018 Economic Benchmarking RIN, including some further minor opening adjustments to account for updates in the AER’s latest ‘revised’ 2016-20 Final Determination (PTRM model) for AusNet Services.

<u>Additions</u> – the allocation of actual additions from RAB roll forward categories into RIN categories is based on additions information contained in Category Analysis RIN Templates 2.2 Repex, 2.3 Augex and 2.5

[2] Excluding Equity Raising Costs - for benchmarking purposes additions include Equity Raising Costs of $10.52 million ($2015) as approved in the AER’s Amended Final Decision PTRM model (2016-2020) – REFCL Tranches 1-3. Additions exclude the capital movement in provisions.

Connections. In some instances, the judgment of an SME was used to apportion additions into the relevant benchmarking RIN categories.

Straight-Line Depreciation – straight-line depreciation into RIN categories is allocated directly where RAB values are directly attributed to RIN categories. For the Distribution and Sub-transmission RAB categories, depreciation is allocated to RIN categories proportionate to their 2019 opening RAB shares.

Estimated Information:

Data provided in Table 3.3.2 for Network Services, Standard Control Services and Meters (Alternate Control Services) are considered Estimated Information with the exception of Other Assets with Long Lives and Other Assets with Short Lives where the information is considered Actual Information.

This is considered Management's best estimate based on the data available. Per the RIN Instructions and Definitions, this information is permitted to be Estimated Information on an ongoing basis.

Table 3.3.3 Total disaggregated RAB asset values

Preparation Methodology:

The total disaggregated RAB values were calculated as the average of the Opening Value and Closing Value for each categorisation of assets presented in Table 3.3.2.

Estimated Information:

The data provided is considered estimated information with the exception of Other Assets with Long Lives, Other Assets with Short Lives and Capital Contributions. The data provided is considered Management's best estimate based on the data available. Per the RIN I&D, this data is permitted to be Estimated Information on an ongoing basis.

Table 3.3.4 Asset lives

Preparation Methodology:

Table 3.3.4.1 Asset Lives – estimated service life of new assets

Data reported as the 'Estimated Service Life of New Assets' is consistent with the information reported in the 2018 Assets (RAB Template). The data reported was reviewed by a SME and no changes were required for the 2019 Regulatory Year. The 2019 data was sourced from data that supports the Category Analysis Asset Age profile template where a weighted average life for grouped assets was calculated. The Asset Age profile data was grouped to align to the Asset Groups required for Table 3.3.4 and is based on 2019 information.

Asset class specific assumptions are:

- DRAB1401: Overhead network assets less than 33kV (wires and poles)
- DRAB1402: Underground network assets less than 33kV (cables)
- DRAB1403: Distribution substations including transformers
- DRAB1404: Overhead network assets 33kV and above (wires and towers / poles etc.)

- DRAB1405: Underground network assets 33kV and above (cables, ducts etc.)
- DRAB1406: Zone substations and transformers

For variable DRAB1407 'Meters', the approved service lives were obtained from the AER's 2016-20 Final Decision for Metering PTRM & Exit Fees. As 'Meters' includes meter equipment, IT, communications and Other metering assets, a weighted average of the service lives was performed (for the five metering subcategories) based on the Closing RAB balance.

For variable DRAB1408 'Other assets with long lives', in the Standard Control RAB this comprises Equity raising costs, SCADA/network control assets and Leasehold Land & Buildings. Previously, and up until 2015, SCADA/network control assets were included in variable DRAB1409 'Other assets with short lives' based on a RAB standard life of 5 years. The standard life for SCADA/network control assets was increased to 10 years commencing from 2016 - as contained in the AER's Final Determination PTRM for AusNet Services (May 2016). The weighted average service life has been calculated using a weighted average of historical capex (2015-2019) for SCADA/network control assets, Lease Land & Buildings and Equity raising costs and the most current standard RAB life assumptions. The standard RAB asset lives have not changed in the AER's Amended 2016-20 Final Decision for AusNet Services (including REFCLs Tranches 1, 2 and 3).

Public Lighting assets which are no longer a Standard Control Service but assumed as Alternative Control Services are also reported under variable DRAB1408 'Other assets with long lives'. The weighted average service life for these assets has been calculated using a weighted average of historical capex (2015-2019) across asset subclasses including poles and brackets, existing luminaires and new energy efficient luminaires. This calculation excludes the 2005 opening RAB values.

DRAB1409 'Other assets – Short lives' is based on the standard RAB asset lives for Non network IT and Other as contained in AusNet Services' Distribution Determination 2016-20. These standard RAB asset lives have not changed in the AER's Amended 2016-20 Final Decision for AusNet Services (including REFCLs Tranches 1, 2 and 3).

Table 3.3.4.2 Asset Lives – estimated residual service life

The 'Estimated Residual Service Life' of the asset group or category, was calculated based on data reported in Template 5.2 Asset Age. The Asset Installation dates included in Template 5.2 Asset Age were used to calculate the Average Asset Lives in each of the Asset Categories. The 'Estimated Residual Service Life' was calculated as the difference between the 'Estimated Service Life of New Assets' and the Average Asset Lives. The data provided is considered Estimated Information as it is based on Estimated Information included in Template 5.2 Asset Age.

For variable DRAB1508 'Other assets with long lives' in the Network Services RAB and Standard Control Services RAB the Weighted Average Remaining Life ("WARL") is based on remaining lives information sourced from the Final Decision RAB roll forward model, updated with 2016-2018 actual net Capex. Straight-line depreciation is applied based on forecast depreciation contained in the AER's Amended 2016-20 Final Decision for AusNet Services (including REFCLs Tranches 1 and 2)

For variable DRAB1507 'Meters' in the Alternative Control Services RAB, the WARL for Metering assets has been derived from RAB information contained in the Roll Forward Model, updated with 2016-2019 actual net Capex as sourced from the annual regulatory accounts, excluding remediation costs. The weighted average calculation of metering assets was based on the Closing RAB balance.

For variable DRAB1508 'Other assets with long lives' in the Alternative Control Services RAB the WARL for Public Lighting assets has been derived from RAB information contained in the Final Decision Public Lighting model published by the AER in May 2016, updated with 2016-2019 actual net Capex including cumulative corrections.

For variable DRAB1509 'Other assets – Short lives' the WARL is based on remaining lives information sourced from the Final Decision RAB roll forward model, updated with 2016-2018 actual net Capex. Straight-line depreciation is applied based on forecast depreciation contained in the AER's Amended 2016-20 Final Decision for AusNet Services (including REFCLs Tranches 1, 2 and 3).

Estimated Information:

Data for Asset Lives is considered Estimated Information. Estimates and assumptions have been outlined above. This is considered to be Management's best estimate based on the data available. Per the RIN Instructions and Definitions, this information is permitted to be Estimated Information on an ongoing basis.

3.4 Operational Data

Table 3.4.1 Energy delivery

Energy delivered is the amount of electricity transported out the network in the relevant period and is measured as the energy metered (or estimated) at the customer charging location.

Preparation Methodology:

- Total Energy Delivered: This data was obtained from the billing system.

- 3.4.1.1 Energy delivery by chargeable quantity: Tariff quantity data (sourced from the supporting documentation to the Annual Regulatory Accounts) was allocated to the categories required by assigning tariffs to a specific chargeable quantity.

  Energy delivered to customers on tariffs that do not have peak, shoulder or off-peak periods was reported in ‘Energy Delivery where time of use is not a determinant’ (DOPED0201).

  Consumption reported for this indicator reflects three types of customers: (1) unmetered consumption related to the provision of electricity to mine sites for electricity generators in the Latrobe Valley, (2) unmetered consumption by connections which are assigned NMIs (AusNet Services’ tariff code NEE52) and unmetered consumption for sites without NMIs. Consumption has been derived from the billing system used to calculate network charges for these customers. (DOPEDO206)

- 3.4.1.2 Energy – received from TNSP and other DNSPs by time of receipt: The data required was calculated based on National Energy Market Meters which record all energy flowing into and out of the transmission connections point, cross boundaries and from embedded generators.

  Total energy received has been included in DOPED0304 ‘Energy received from TNSP and other DNSPs not included in the above categories’ as it is not possible to allocate the available energy received information into the defined on-peak, shoulder and off-peak times without a specific definition of those time periods (AusNet Electricity Services has multiple peak and off-peak time periods across its tariff classes, it is not possible to determine which ‘peak’ time (for example) should be used).

- 3.4.1.3 Energy – received into DNSP system from embedded generation by time of receipt: The non-residential data required was calculated based on information directly extracted from National Energy Market Meters. Energy from residential embedded generation is a combination of billed energy as well as interval data energy for customers that are not billed for generation into the network.

  Total energy received from non-residential embedded generation has been included in DOPED0404 ‘Energy received from embedded generation not included in above categories from non-residential embedded generation’ as it is not possible to allocate the available energy received information into the defined on-peak, shoulder and off-peak times without a specific definition of those time periods.

  Total energy received from residential embedded generation has been included in DOPED0408 ‘Energy received from embedded generation not included in above categories from residential embedded generation' as it is not possible to allocate the available energy received information into the defined on-peak, shoulder and off-peak times.

- 3.4.1.4 Energy grouping – customer type or class: Tariff quantity data sourced from the supporting documentation to the Annual Regulatory Accounts (which was ultimately sourced from customer billing data) was allocated to the categories required by assigning each tariff to a specific customer type or class.

  Unmetered energy delivery was reported in 'Other Customer Class Energy Deliveries' (DOPED0505). This includes energy deemed to be delivered to the three Latrobe Valley mine sites (Loy Yang, Morwell, Yallourn).

  Consumption reported for this indicator reflects three types of customers: (1) unmetered consumption related to the provision of electricity to mine sites for electricity generators in the Latrobe Valley, (2) unmetered consumption by connections which are assigned NMIs (AusNet Services' tariff code NEE52) and unmetered consumption for sites without NMIs. Consumption has been derived from the billing system used to calculate network charges for these customers.

Table 3.4.2 Customer numbers

Distribution Customers for a Regulatory Year are defined as the average number of energised and de-energised National Meter Identifiers ("NMIs") in AusNet Electricity Services' network in that year, plus unmetered customers but excluding extinct NMIs. The average is calculated as the average of the number of customers on the first day of the Regulatory Year and the last day of the Regulatory Year.

For unmetered customers, Customer Numbers are the sum of connections (excluding public lighting connections) that do not have a NMI and the energy usage for billing purposes is calculated using an assumed load profile (examples include bus shelters, security lighting and traffic signals where not metered). Public lighting connections are not included as unmetered customers.

Preparation Methodology:

The total average customer numbers were obtained from combined extracts from AusNet Services' SAP Customer Information System and spatial system SDME. The split of customer numbers into the prescribed categories was determined as follows -

- Table 3.4.2.1 Distribution customer numbers by customer type or class: a table which combines SAP and SDME data contains information that determines the energised status of each NMI, as well as the dates for which the NMI was active. This data was joined to another table from CIS which contains the tariff code for each NMI. Tariff codes were mapped to RIN categories on a one-for-one basis.

  'Unmetered customer numbers' (DOPCN0105) was obtained directly from the New Connections Unmetered Supplies ("UMS") database, plus the three generation sites in the Latrobe Valley (Loy Yang, Morwell, Yallourn).

- Table 3.4.2.2 Distribution customer numbers by location on the network: Using data extracted from the Service Order Management System, the percentage of customers by the three feeder categories (Urban, Short Rural and Long Rural) was obtained. These percentages were applied to the total average customer numbers per Table 3.4.2.1 to derive the number of distribution customer numbers by location on the network.

  The categorisations are based on the feeder locations (Urban, Short Rural and Long Rural) in the 2019 Regulatory Year.

Table 3.4.2.4 was obtained from DOPCN0105. Table 3.4.2.3 is not applicable to AusNet Electricity Services.

Estimated Information:

Information reported is Actual Information. No estimates were required.

Table 3.4.3 System demand

Preparation Methodology:

Table 3.4.3.1 Annual system maximum demand characteristics at the zone substation level.

Daily non-coincidental maximum demand data was extracted from OSI Pi. Using this information, the maximum demand day at each substation was identified. The attributes at the time of peak (MW, MVA, Date, Time) were determined for each zone substation for 2019.

30 minute maximum demand data was extracted from OSI Pi for each zone substation, providing daily coincidental maximum demand information (date, time). Using this information, the maximum MVA and the attributes at the time of peak (MW, MVA) were determined for each zone substation for 2019.

Table 3.4.3.2 Annual system maximum demand characteristics at the transmission connection point – MW measure

Non-coincident Summated Raw System Annual Maximum Demand:

AusNet Electricity Services has calculated demand based on National Energy Market Meter data supplied from the transmission business.

Coincident Raw System Annual Maximum Demand:

Information was sourced from the National Energy Market Meters (both Terminal Station, Boundary and Generator Meters). The network meters have been reconciled with AEMO and AusNet Services' Protection department to ensure all applicable meters are accounted for in calculating the Maximum Demand on the network.

Daily coincidental maximum demand data was extracted for the network for all days in 2019. Using this information, the maximum demand day was identified for each year. Using information described above, the yearly attributes at the time of peak (MW, MVA, Date, Time, Peak) was identified.

Table 3.4.3.3 Annual system maximum demand characteristics at the zone substation level – MVA measure

Daily non-coincidental maximum demand data was extracted from OSI Pi. Using this information, the maximum demand day at each substation was identified. The attributes at the time of peak (MW, MVA, Date, Time) were determined for each zone substation for 2019.

30 minute maximum demand data was extracted from OSI Pi for each zone substation, providing daily coincidental maximum demand information (date, time). Using this information, the maximum MVA and the attributes at the time of peak (MW, MVA) were determined for each zone substation for 2019.

Table 3.4.3.4 Annual system maximum demand characteristics at the transmission connection point – MVA measure

Non-coincident Summated Raw System Annual Maximum Demand:

AusNet Electricity Services has calculated demand based on National Energy Market Meter data supplied from the transmission business.

Coincident Raw System Annual Maximum Demand:

Information was sourced from the National Energy Market Meters (both Terminal Station, Boundary and Generator Meters). The network meters have been reconciled with AEMO and AusNet Services' Protection department to ensure all applicable meters are accounted for in calculating the Maximum Demand on the network.

Daily coincidental maximum demand data was extracted for the network for all days in 2019. Using this information, the maximum demand day was identified for each year. Using information described above, the yearly attributes at the time of peak (MW, MVA, Date, Time, Peak) were identified.

Weather adjusted Maximum Demand (all reporting lines)

AusNet Services' POE10 and POE50 demand forecasts are developed at a feeder level. Each feeder has its own temperature-demand relationship calculated, resulting in an 's-curve' for each feeder (where demand increases with temperature on a non-linear basis and then saturates once the temperature reaches a certain point). This means that at a zone substation level, weather-correcting demand data is a very complex process. For RIN reporting purposes, weather correction uses the average of five feeders' s-curves (PHM33, CLN23, BDL4, BGE22, BN1) to estimate the temperature-demand relationship for all zone substations.

The following methodology has been used to estimate weather-corrected demand:

- Assign each zone substation to one of AusNet Services' three regions: central, east and north.
- Obtain daily maximum temperature data from the Bureau of Meteorology for three weather stations within these regions: Scoresby Research Institute (central), East Sale Airport (east), Wangaratta Aero (north).
- If the zone substation is winter-peaking, assume that the weather-corrected demand is the same as the recorded demand.
- If the zone substation is summer peaking, but the temperature on the date that maximum demand was recorded was below 23 degrees, assume that the weather-corrected demand is the same as the recorded demand.
- If the zone substation is summer peaking and the temperature on the date that maximum demand was recorded was above 23 degrees:
    - Divide the recorded demand by a ratio of (1) the position on the averaged s-curve for the temperature on the maximum demand day and (2) the relevant POE temperature (38 degrees for POE50 and 46 degrees for POE10). For example, maximum demand recorded on a day with a recorded temperature of lower than 38 degrees will be adjusted up for POE50 purposes, depending on where on the curve the maximum demand day sits, relative to 38 degrees.

Estimated Information:

Weather corrected maximum demand is Estimated Information. This is considered Management's best estimate based on the data available.

3.4.3.5 Power factor conversion between MVA and MW

- Average overall network power factor conversion between MVA and MW (DOPSD0301) was calculated as DOPSD0107 divided by DOPSD0207.

- Average power factor conversion for SWER lines (DOPSD0307) was estimated using a sample of SCADA data for SWER ACR's.

- Average power factor conversion for 22 kV lines (DOPSD0308) was based on 2019 data from the SCADA system.

- Average power factor conversion for 6.6 kV lines (DOPSD0304) was calculated based on 2019 data from the SCADA system using the MW and MVAR flowing through the elements in the network that operate at 6.6kV.

- The 'Average power factor conversion for 66 kV lines' (DOPSD0311) was calculated as DOPSD0101 divided by DOPSD0201 as the energy flowing into the Zone Substations is assumed to be the same as flowing in the 66kV lines.

- Low voltage distribution lines have been estimated with reference to the Electricity Distribution Code and the calculated power factor for 22kV lines. AusNet Services low voltage customers are obliged to maintain their power factor as per the Distribution Code. This is stipulated in our connection agreements. The 22kV power factor reported in the RIN is 0.992, which is a reflection of the power factor maintained at low voltage. On this basis AusNet Services average long-term low voltage power factor can be assessed to be > 0.85 (lagging) or on average 0.90 (lagging). Therefore, 0.90 has been reported for this indicator.

- AusNet Services' 11kV feeders are dedicated to Latrobe Valley generation assets (e.g. mine supplies), as a result they do not supply other customers. The power factor of these few feeders has been assessed to be within 0.8 to 0.9.

Estimated Information:

Estimates were required in relation to power factors reported (variables DOPSD0302 and DOPSD0306) as system generated information is not available in the categorisation required. This is considered to be Management's best estimate based on the data available. Based on the RIN Instructions and Definitions, this information is permitted to be Estimated Information on an ongoing basis where Actual Information is not available.

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

Preparation Methodology:

Tariff quantity data (sourced from the supporting documentation to the Annual Regulatory Accounts) was allocated to this category on the basis of those customers who are charged for their demand on a MW basis. This encompasses those customers on a 'NASN*' tariff.

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

Preparation Methodology:

'Summated Chargeable Contracted Maximum Demand' (DOPSD0403) information was obtained from customer billing data. It represents the contracted capacity of infrastructure (with reference to the rating of assets such as transformers, switchgear and cabling) to supply AusNet Services' large (>160 MWh p.a.) customers.

'Summated Chargeable Measured Maximum Demand' (DOPSD0404) was obtained from customer billings. It represents the measured maximum demand of large customers on days that AusNet Services has designated as Critical Peak Demand days. Customers are notified of these days with a minimum of one business day's notice.

Estimated Information:

Information reported is Actual Information. No estimates were required.

3.5 Physical Assets

Table 3.5.1.1 Overhead network length of circuit at each voltage
Table 3.5.1.2 Underground network circuit length at each voltage

Network capacity variables are reported for the whole network including overhead power lines, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers. Network also includes distribution feeders and the low voltage distribution system but excludes the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.

In relation to Table 3.5.1.1 'Overhead network length of circuit at each voltage' and Table 3.5.1.2 'Underground network circuit length at each voltage', circuit length is calculated from the length (measured in kilometres) of lines in service, where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines. The length does not take into account vertical components such as sag.

Preparation Methodology:

For the 2016 Regulatory Year, a report was generated in the Asset Management System (SDME) which provided the voltage and length attributes required. The data was allocated into the specified categories taking into consideration the inclusions and exclusions discussed above. The report used was generated on 1 January 2019 to provide the circuit length as at 31 December 2019.

The information provided is considered 'actual information' as it was extracted from the SDME system, however it is noted that the system data has been subject to data cleansing and updating over the Regulatory Years.

Table 3.5.1.3 Estimated overhead network weighted average MVA capacity by voltage class
Table 3.5.1.4 Estimated underground network weighted average MVA capacity by voltage class

Weighted average capacities have been reported for both the overhead and underground network in the required voltage classes.

Preparation Methodology:

Data for the 2019 Regulatory Year was sourced from the Asset Management System (SDME) - including the conductor voltage ("Volts") and line length in kilometres ("length") for each section of line. The report extracted from SDME included details such as 'Specification' and 'Dictionary' name. These parameters were used to determine the associated amp rating. An internal document is maintained defining all Dictionary names.

Actual amp ratings were used which are considered to be reflective of operational ratings. The rating used to calculate the circuit capacity are the ratings of the particular conductor type at its design temperature (50^0C, 60^0C and etc), i.e. these are not adjusted for restrictions or limitations imposed on the capacity of the conductor due to its location in the network. Further, the amp ratings are not adjusted for lines which are constrained by voltage as voltage only constrains a small number of lines and changing the methodology to incorporate these voltage constrained lines is not expected to materially change the weighted average MVA capacity by voltage class.

Where the data extracted from SMDE didn't provide sufficient information to determine the amp ratings, additional information was sourced from a Feeder ratings database maintained by the Regional Network Planners. This database includes information for the North, East and South regions. Inputs to the database are based on historic internal information and also internal policy document AMS 20-24 'Sub-transmission line and Station Data for Planning Purposes'.

The weighted average was calculated based on the following methodology:

$$\frac{\text{Line 1: (length * Volts * Amps) + Line 2: (length * Volts * Amps) + Line 3: (length * Volts * Amps) etc.}}{\text{(Line 1 length + Line 2 length + Line 3 length etc.)}}$$

For three phase lines each group in the numerator has also been multiplied by $\sqrt{3}$.

However, for SWER MVA the capacities were derived based on the summation of the product of individual transformer unit size (e.g. 50 kVA, 100 kVA, 200 kVA) and the length of SWER lines for each transformer unit size divided by the total length of SWER lines for both overhead and underground.

The network weighted average MVA capacity of SWER networks the following methodology was used:

(50kVA transformer unit * Length of lines with 50kVA transformer units) + (100kVA transformer unit * Length of lines with 100kVA transformer units) + (200kVA transformer unit * Length of lines with 200kVA transformer units) *divided* by the total length of SWER lines.

The information provided is considered 'actual information' as it was extracted from the SDME system and sourced from supporting AusNet documentation, however it is noted that the system data has been subject to data cleansing and updating over the Regulatory Years.

Table 3.5.2 Transformer Capacities Variables

Table 3.5.2.1 Distribution transformer total installed capacity

A Distribution Transformer is a transformer that provides the final voltage transformation in the electricity distribution system, stepping down the voltage used in the distribution lines to the level used by the customer.

The total installed Distribution Transformer capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (e.g. 132kV, 66kV, 22kV or 11kV) distribution level. The capacity measure is the normal nameplate continuous capacity/rating (including forced cooling and other factors used to improve capacity).

Distribution Transformer capacity involved in the final level of transformation owned by AusNet Electricity Services and owned by High Voltage Customers has been reported.

Cold spare capacity is the capacity of spare transformers owned by AusNet Electricity Services but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations, but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and / or making of connections would require manual intervention at the site of use.

Preparation Methodology:

Information in relation to 'Distribution Transformer capacity owned by AusNet Services' was sourced directly from SDME - including the kVA capacity rating, and substation type.

'Distribution Transformer capacity owned by High Voltage customers' was extracted based on Capacity charges that are paid by customers, which reflect the rating of the cabling and switchgear at the customer connection point. The data (in kVA) is taken from Annual AER Tariff Submissions and is originally sourced from the billing system.

This information is based on what is charged to the customer at a peak rate and assumes this calculation as a maximum capacity. This is not what the customer has installed and will underestimate the actual installed rated capacity 'Cold Spare Capacity' (DPA0503) was sourced from a 'stock on hand' report generated in SAP. The report used was generated on 7 January 2019 to provide the Cold Spare Capacity at 31 December 2019.

Estimated Information:

Information reported is Actual Information. No estimates were required, except for variable DPA0502 Distribution transformer capacity owned by High Voltage Customers where Ausnet Electricity Services cannot access this information from its HV customers.

Table 3.5.2.2 Zone substation transformer capacity

'Total installed capacity for first step transformation where there are two steps to reach distribution voltage' (DPA0601) and 'Total installed capacity for second step transformation where there are two steps to reach distribution voltage' (DPA0602) has been reported as zero on the basis that AusNet Electricity Services does not have installed capacity with more than one step or transformation.

'Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage' (DPA0603) has been reported where there is only a single step of transformation.

Power transformer rating includes cooling mechanisms. It is the summer cyclic rating as defined and calculated in AMS 20-101'Cold Spare Capacity of zone substation transformers included in DPA0604' (DPA0605) has reported total Cold Spare Capacity included in total zone substation transformer capacity.

'Total zone substation transformer capacity' (DPA0604) was calculated as the sum of variables DPA0601, DPA0602, DPA0603 and DPA0605.

Station service transformers have been excluded.

Preparation Methodology:

Table 3.5.2.2 was prepared on an asset by asset basis using information sourced from internal policy AMS 20-101 Zone Substation Transformer Cyclic Ratings (for Total Installed Capacity) which is used for the Distribution Annual Planning Report and AMS 20-90 Zone Substation Transformer Contingency Plan (for Cold Spare Capacity). Any variations between the publications and the data reported was sourced from SMEs.

Included in DPA0605 'Cold spare capacity of zone substation transformers included in DPA0604' is 90.5MVA relating to cold spare capacity that can only be utilised at Yallourn Power Station.

The ratings assumed were based on the nameplate capacity of the transformer unit.

Estimated Information:

Information reported is Actual Information. No estimates were required.

Table 3.5.2.3 Distribution - Other transformer capacity

Preparation Methodology:

Table 3.5.2.3 was prepared on an asset by asset basis using information sourced from internal policy AMS 20-101 Zone Substation Transformer Cyclic Ratings which is used for the Distribution Annual Planning Report. The ratings assumed were based on the nameplate capacity of the transformer unit.

Estimated Information:

Information reported is Actual Information. No estimates were required.

Table 3.5.3 Public lighting

Preparation Methodology:

A report generated in the SDME Spatial System was used to provide the data required for Public Lighting Luminaires (DPA0701) for the 2019 Regulatory Year. The information provided is considered Actual Information as it was extracted from the system and the presentation is not contingent on judgments and assumptions for which there are valid alternatives.

In relation to the number of Public Lighting Poles (DPA0702), data was extracted directly from the SDME Spatial System. The information provided is considered Actual Information as it was extracted from the system.

3.6 Quality of Service

Table 3.6.1 Reliability

An interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network, including generation facilities and transmission networks, of more than 0.5 seconds, including outages affecting a single premise. The customer interruption starts when it is recorded by equipment such as SCADA or, where such equipment does not exist, at the time of the first customer call relating to the network outage. An interruption may be planned or unplanned, momentary or sustained. It does not include subsequent interruptions caused by network switching during fault finding. An interruption ends when supply is again generally available to the customer.

In this section reliability information is reported for unplanned interruptions, which is an interruption due to an unplanned event. An unplanned event is considered an event that causes an interruption where the customer has not been given the required notice for the interruption or where the customer has not requested the outage.

System Average Interruption Duration Index ("SAIDI") is the sum of the duration of each unplanned sustained Customer interruption (in minutes) divided by the average number of Distribution Customers. SAIDI excludes momentary interruptions (interruptions of less than one minute[3]).

System Average Interruption Frequency Index ("SAIFI") is the total number of unplanned sustained Customer interruptions divided by the average number of Distribution Customers. Unplanned SAIFI excludes momentary interruptions (interruptions of less than one minute).

Whole of network SAIDI and SAIFI is the system wide SAIDI and SAIFI.

Section 3.3(a) of the Electricity Distribution Network Service Providers – STPIS (Version 2) Nov 2018 Amendment outlines the exemption criteria applicable in the EDPR period 2016-2020. Events that fall in any of the following conditions may be excluded in calculating the revenue increment or decrement as well as annual performance under the STPIS scheme.

1. [Deleted]
2. load shedding due to a generation shortfall;
3. automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition;
4. load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator;
5. load interruptions caused by a failure of the shared transmission network;

[3] During the March 2018 audit, AusNet Services advised the WSP auditors that PowerOn Outage Management System reports have been configured to flag supply interruptions of less than 60 seconds (1 minute) as momentary – consistent with the Electricity Distribution Code. AusNet Services have consistently reported annual RINs based on the Code definition of momentary interruption. On the other hand, the RIN Instructions and Definitions document suggests that "SAIDI excludes momentary interruptions (interruptions of one minute or less)". This means RIN defines momentary interruptions as supply interruptions with duration of one minute or less, which is inconsistent with the Code. The WSP auditors assessed the impact of this definition discrepancy on reported USAIDI, USAIFI and MAIFI values and found the variances to be negligible, hence the reported Code-based values can still be treated as actual information.

6. load interruptions caused by a failure of transmission connection assets except where the interruptions were due to:
   (a) actions, or inactions, of the DNSP that are inconsistent with good industry practice; or
   (b) inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning
7. load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.
8. load interruptions caused or extended by a direction from state or federal emergency services, provided that a fault in, or the operation of, the network did not cause, in whole or part, the event giving rise to the direction.

There was one incident related to failure of inter-distributor connection resulting to supply interruption to AusNet Services customers that are connected to the Tumut River County (TRC01) feeder of Essential Energy (NSW). This supply interruption meets the exclusion criteria 3.3(a)(6).

Two transmission events resulted to supply interruptions to customers connected to Wodonga and Ringwood Terminal stations. These supply interruptions meet the exclusion criteria 3.3(a)(5).

There were five supply interruptions that occurred during Total Fire Ban (TFB) days as a result of the mandatory suppression of reclose functions on protective devices in areas covered by a TFB declaration. These supply interruptions meet the exclusion criteria 3.3(a)(7).

Table 3.6.1.1 Inclusive of Major Event Days

<u>Preparation Methodology</u>:

Information was sourced from AER 2019 Annual Regulatory Non-Financial Information Templates RIN ("Annual RIN Report").

Whole of network unplanned SAIDI (DQS0101) – 'Unplanned Minutes-Off-Supply' are obtained from the 2019 Annual RIN Report and divided by the average number of distribution customers connected to the network in calendar year 2019.

Whole of network unplanned SAIDI excluding excluded outages (DQS0102) - the annual total 'Unplanned Minutes-Off-Supply' from network events that are ineligible for exclusion according to Section 3.3(a) of the 2016-2020 EDPR STPIS were obtained from the PowerOn network outage historical data and divided by the average number of distribution customers connected to the network in calendar year 2019. The total minutes (SAIDI) from excluded events were subtracted from the 'Whole of network unplanned SAIDI' in Table 3.6.1 (DQS0101).

Whole of network unplanned SAIFI (DQS0103) – 'Unplanned Interruptions' was obtained from the 2019 Annual RIN Report and divided by the average number of distribution customers connected to the network in calendar year 2019.

Whole of network unplanned SAIFI excluding excluded outages (DQS0104) - the annual total 'Unplanned Interruptions' from network events that are ineligible for exclusion according to Section 3.3(a) of the 2016-2020 EDPR STPIS was obtained from the PowerOn system network outage historical data and divided by the average number of distribution customers connected to the network in calendar year 2019. The total customer interruptions (SAIFI) from excluded events were subtracted from the 'Whole of network unplanned SAIFI' in Table 3.6.1 (DQS0103).

Estimated Information:

No estimates were required.

Table 3.6.1.2 Exclusive of Major Event Days

Preparation Methodology:

Historical outage data from the PowerOn System was used to calculate the daily unplanned SAIDI and SAIFI in 2019.

The Major Event Days ("MED") threshold was calculated for the 2019 Regulatory Year from the daily Unplanned SAIDI data between Regulatory Years 2013 and 2017 (5 years) using the annual AER RIN Template MED calculator.

In relation to 'Whole of network unplanned SAIDI' (DQS0105) and 'Whole of network unplanned SAIFI' (DQS0107) - the summed unplanned SAIDI for all MEDs was subtracted from the Total SAIDI value in Table 3.6.1 (DQS0101) to obtain the SAIDI performance exclusive of the MED impact. The same process was followed for unplanned SAIFI.

'Whole of network unplanned SAIDI excluding excluded outages' (DQS0106): the total minutes (SAIDI) from excluded events were subtracted from the 'Whole of network unplanned SAIDI' exclusive of MED (DQS0105). The same process was followed for 'Whole of network unplanned SAIFI with excluded outages'.

Estimated Information:

Information reported is Actual Information. No estimates were required.

Table 3.6.2 Energy not supplied

Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions and is reported exclusive of the effect of Excluded Outages.

Preparation Methodology:

The reported values of energy not supplied were obtained from the 2019 Annual Regulatory Accounts.

An estimate was performed of the raw (not normalised) energy not supplied due to unplanned customer interruptions. The estimate was calculated based on average customer demand multiplied by the number of customers interrupted and the duration of the interruption. Average customer demand was determined from average consumption of customers on the feeder based on their billing history.

Data reported for DQS0202 has been reported exclusive of the effect of Excluded Outages (i.e. STPIS Exclusions 3.3 (a) only).

Estimated Information:

Estimates provided for ‘Energy not supplied’ are considered Management’s best estimate based on the data available. Per the RIN Instructions and Definitions, this information is permitted to be Estimated Information on an ongoing basis.

Table 3.6.3 System losses

System losses are the proportion of energy that is lost in the distribution of electricity from the transmission network to customers. It has been calculated as the difference between electricity imported and electricity delivered as a percentage of electricity imported.

Electricity imported is the total electricity inflow into the distribution network (including from Embedded Generation) less the total electricity outflow into the networks of the adjacent connected distribution network service providers or the transmission network.

Electricity delivered is the amount of electricity transported out of the network to customers as metered (or otherwise calculated) at the customer’s connection. This is a system wide figure not a feeder level figure.

Preparation Methodology:

System losses are calculated as the sum of

(DOPED0304 ‘Energy received from TNSP and other DNSPs not included in the above categories’ +

DOPED0404 ‘Energy received from embedded generation not included in above categories from non-residential embedded generation’ +

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

DOPED01 ‘Total Energy Delivered’)

divided by

(DOPED0404 ‘Energy received from embedded generation not included in above categories from non-residential embedded generation’ +

DOPED0408 ‘Energy received from embedded generation not included in above categories from residential embedded generation’ +

DOPED0304 'Energy received from TNSP and other DNSPs not included in the above categories').

Estimated Information:

Information reported is Actual Information. No estimates were required.

Table 3.6.4 Capacity utilisation

Capacity utilisation is a measure of the capacity of zone substation transformers that is utilised in the 2019 Regulatory Year. The sum of non-coincident Maximum Demand at the zone substation level divided by summation of zone substation thermal capacity is reported.

Thermal capacity is the rated continuous load capacity of the zone substation (with forced cooling or other capacity improving factors included if relevant) being the lowest of either the transformer capacity or feeder exit capacity of the zone substation. Feeder exit capacity is the continuous rating.

Preparation Methodology:

Data was calculated as variable DOPSD0201 Non–coincident Summated Raw System Annual Maximum Demand divided by variable DPA0604 Total zone substation transformer capacity.

Estimated Information:

Information reported is Actual Information. No estimates were required.

3.7 Operating Environment

Table 3.7.1 Density factors

'Customer Density' (DOEF0101) is the total number of customers divided by the route line length of the network.

'Energy Density' (DOEF0102) is the total MWh divided by the total number of customers of the network.

'Demand Density' (DOEF0103) is the kVA non-coincident Maximum Demand (at zone substation level) divided by the total number of customers of the network.

Preparation Methodology:

'Customer Density' (DOEF0101) was calculated as 'Total Customer Numbers' (DOPCN01) divided by 'Route Line Length' (DOEF0301). Route Line Length includes both Overhead Route Line Length and Underground Route Line Length.

'Energy Density' (DOEF0102) was calculated as the 'Total Energy Delivered' in GWh (DOPED01) x 1000 divided by 'Total Customer Numbers' (DOPCN01) using actual information.

'Demand Density' (DOEF0103) was calculated as DOPSD0201 'Non–coincident Summated Raw System Annual Maximum Demand' x 1000 divided by 'Total Customer Numbers' (DOPCN01) using actual information.

Estimated Information:

'Customer Density' (DOEF0101) information is considered estimated information as the 'Route Line Length' (DOEF0301) variable included in the calculation of customer density was estimated.

This is considered Management's best estimate based on the data available.

Table 3.7.2 Terrain factors

A. Rural proportion (DOEF0201):

Rural proportion is the distribution route length classified as short rural or long rural in kilometres ("km") divided by the total network line length.

Preparation Methodology:

Using the HV line length data by feeder from SDME, the proportion of high voltage line lengths connected to rural (i.e. short, long) feeders to the total line length of the distribution network was calculated considering both overhead and underground lines. It excludes sub-transmission (i.e. 66kV) and low voltage networks.

Estimated Information:

As the current system does not distinguish between rural and urban route line length, SDME feeder data has been used as a proxy to calculate the required information. This is considered Management's best estimate based on the data available. Per the RIN Instructions and Definitions, this information is allowed to be Estimated Information on an ongoing basis where actual information is not available.

B. Urban and CBD vegetation maintenance spans (DOEF0202), Rural vegetation maintenance spans (DOEF0203), Total vegetation maintenance spans (DOEF0204) and Total number of spans (DOEF0205)

A Maintenance span is the network span that is subject to active vegetation management practices in the relevant year. Active vegetation management practices do not include inspection of vegetation maintenance spans - where 'inspection' is only for the purpose of identifying trees or other vegetation that require trimming or removal and includes vegetation scoping works.

Urban and CBD maintenance spans refers to CBD and urban areas that are subject to vegetation management practices in the relevant Regulatory Year. CBD and urban areas are consistent with CBD and urban customer classifications.

Rural maintenance spans refer to spans in rural areas that are subject to vegetation management practices in the relevant year. Rural spans include spans in short rural and long rural feeders.

A Jobs Data Extract is run from the Vegetation Management System ("VMS") on a monthly basis. This report includes information such as Feeder, Firezone (HBRA or LBRA) with a Span Cut code (C365, C720, CCC, CRE).

This report is run with the date range of the last financial operating day of the previous year to the last financial operating day of the RIN period. A span is counted as a Maintenance Span when the payment for cutting occurs in the regulatory year.

A count of all Cut (C365, C720, CCC, CRE) spans are determined via a pivot table, which is split into HBRA (Urban and Rural) and LBRA (Urban and Rural). In order to split the data into Urban and Rural, a column is added to the spreadsheet titled 'Classification' to match the feeder name with the Urban and Rural classification provided by the AusNet Services Analytics team. This process provides information for DOEF0202 and DOEF0203.

DOEF0202 and DOEF0203 only include spans subject to action/cutting rather than inspection or assessment. 'Total Vegetation Maintenance spans' (DOEF0204) was calculated as the sum of 'Urban and CBD vegetation maintenance spans' (DOEF0202) and 'Rural vegetation maintenance spans' (DOEF0203).

The information for DOEF0202, DOEF0203 and DOEF0204 was extracted from the VMS. The data reported excludes 66kV sub-transmission lines as the feeder classifications (i.e. Urban, Short Rural, Long Rural) do not apply. Urban, Short Rural and Long Rural classifications are only applicable to feeders with voltage levels between 6.6kV and 22kV which a distributor uses to distribute electricity (per the Electricity Distribution Code). These classifications cannot be applied to sub-transmission feeders (i.e. 66kV) and higher voltage levels. The omission of these lines represents a percentage of <3% of total spans which AusNet Services considers immaterial.

'Total number of spans' (DOEF0205) is contained in the Progress Report (1/01/19 to 31/12/19) and Missing Pole Pairs spreadsheets. This number excludes all underground cables and stand-alone assets not connected by an overhead wire (such as street light poles etc.). This information was extracted from the VMS.

<u>Estimated Information:</u>

Information reported is Actual Information. No estimates were required.

C. Average urban and CBD vegetation maintenance span cycle (DOEF0206) and Average rural vegetation maintenance span cycle (DOEF0207)

Maintenance span cycle refers to the planned number of years between which cyclic vegetation maintenance is performed for the relevant area. Information in relation to the average vegetation maintenance span cycles was obtained from the VMS.

<u>Estimated Information:</u>

Information reported is Actual Information. No estimates were required.

D. Average number of trees per urban and CBD vegetation maintenance span (DOEF0208) and Average number of trees per rural vegetation maintenance span (DOEF0209)

The ‘Average number of trees per maintenance span’ includes only trees that require active vegetation management to meet vegetation management obligations. It excludes trees that only require inspections and no other vegetation management activities are needed to comply with AusNet Electricity Services’ vegetation management obligations.

Vegetation Management field staff record the number of trees to be actioned (PT1, PT30, PT180, PT365) in each span into the VMS. Systems analyst runs an ‘Assets Data Extract’ for the regulatory year from the VMS. Data generated is divided by the number of spans to quantify average numbers of actioned trees per maintenance span (C365, C720, CCC, CRE) which is split into HBRA (Urban and Rural) and LBRA (Urban and Rural).

<u>Estimated Information:</u>

Information reported is Actual Information. No estimates were required. ***E. Average number of defects per urban and CBD vegetation maintenance span (DOEF0210) and Average number of defects per rural vegetation maintenance span (DOEF0211)***

Defects are any recorded incidence of non-compliance with a NSP’s vegetation clearance standard and include vegetation outside the standard clearance zone that is recognised as hazardous vegetation and would normally be reported as requiring management under inspection practices. Defects on a vegetation span are recorded as one, regardless of the number of defects on the span.

A new VMS system was introduced during the 2019 regulatory year and the Hazard Trees workflow has been included in the upgrade.

To calculate the average number of defects per vegetation maintenance span, information was extracted from the following sources; ‘Jobs Data Extract” & Hazard Trees Jobs Data Extract from the new VMS, LIDAR Hazard Trees Spreadsheet and the Hazard Tree Database (which is an Access database). The total number of defects (Rural /Urban and CBD) is calculated as the number of PT1 and PT30 Cut spans as per the 'Jobs Data Extract', plus any rating 1, 2, 3, 4 & 5 Hazard Trees (meaning Trees which required action due to defects) as recorded in the VMS, LIDAR Hazard Trees Spreadsheet and Hazard Tree Database.

To calculate the average number of defects, the total number of defects was divided by the number of vegetation maintenance spans.

The calculation excludes 66kv Sub-Transmission lines for Urban and CBD feeders as AusNet Services cannot provide the classification for these lines. The omission of these lines represents around <6% of total spans.

Estimated Information:

Information reported is Actual Information. No estimates were required.

F. Tropical Spans (DOEF0212)

Tropical spans are the approximate total number of urban and rural Maintenance Spans in the 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). There are no Tropical Spans in AusNet Electricity Services' urban and rural Maintenance Spans.

Estimated Information:

Information reported is Actual Information. No estimates were required.

G. Standard Vehicle Access (DOEF0213)

Standard vehicle access refers to areas which are serviced through made roads, gravel roads and open paddocks (including gated and fenced paddocks). This relates to spans that can't be accessed by a two-wheel drive vehicle.

A new VMS system was introduced for the 2019 regulatory year which sources asset information from SDME. The transition to the new system has meant that actual data has been used to calculate kilometres for Standard Vehicle Access.

To calculate the kilometres of maintenance spans for Standard Vehicle Access, a 'Jobs Data Extract' is run out of the VMS. This report identifies which of the priority spans (PT1, PT30, PT180 and PT365), that didn't require Vehicle Access and Non-Standard Vehicle Access during the Regulatory Year. The data is calculated by a Pivot Table using the column headed "Vehicle Access", summing the total span length and dividing by 1000 to provide the total in kilometres. The data is divided into LBRA Urban and CBD and HBRA Rural.

Estimated Information:

All information reported is Actual Information. No estimates were required.

H. Bushfire Risk (DOEF0214)

Bushfire risk is the number of Maintenance Spans in high bushfire risk areas.

Using the 'Jobs Data Extract' from new VMS, Old VMS SQL Query and Missing Pole Pairs Spreadsheet, the count of HBRA Cut (C365, C720, CCC, CRE) spans is extracted. These figures include all feeders because the Bushfire Risk variable does not need to be distinguished into HBRA and LBRA, Urban/CBD and Rural.

The 'Cut' spans are used instead of 'Assess' spans as the AER definition of Bushfire Risk references number of 'Maintenance Spans'; the AER defines that Maintenance Spans do not include inspections.

The HBRA classifications held within VMS are determined via reference to Country Fire Authority information

Estimated Information:

Information reported is Actual Information. No estimates were required.

Table 3.7.3 Service area factors

The Route Line Length is the aggregated length in kilometres of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag.

Preparation Methodology:

The route line lengths for overhead and underground were summed to calculate the total route line length.

Overhead Route Line Length:

For the 2019 Regulatory Year, overhead line length data was extracted from the SDME Asset Management System. In SDME, high voltage (HV) and low voltage (LV) overhead conductors are connected to poles (or nodes) which allow the calculation of span line lengths with single or multiple circuits. A report was generated from the SDME Asset Management System which provided the information required for Overhead Route Line Length.

Underground Route Line Length:

Underground conductor circuit line lengths are available in SDME. However, since underground construction do not have poles (or nodes) for span line length calculation, the HV and LV Underground Route Line Lengths for calendar year 2019 were estimated using the same factors calculated and applied to the calendar year 2019 underground route length calculation.

Listed below are the steps undertaken in 2019 to calculate underground circuit route factors:

- A report was generated from the SDME Asset Management System which provided the underground circuit length by feeder and by HV and LV – split between urban, short rural and long rural.
- Sample feeders were selected in each of the urban, short rural and long rural feeder classifications. A total of nineteen feeders were investigated representing 5.5% of total distribution feeders.
- For each feeder in the sample, geographic routes were investigated by a subject matter expert and the underground route line length was calculated.
- For each feeder in the sample, the ratio of calculated route line length to circuit length was determined (the "factor") and a weighted average factor was calculated for the urban, short rural and long rural feeder classifications.

The weighted average factors and calculation performed is as per below:

Urban feeder	= 92.8% x total urban underground circuit length
Rural short feeder	= 96.9% x total rural short underground circuit length
Rural long feeder	= 98.9% x total rural long underground circuit length

- LV underground route length:
  - Factors above for urban, short rural and long rural feeders were applied to the LV circuit lengths from SDME to estimate the LV underground route line length.
- HV underground route length:
  - It is estimated (via desktop survey in SDME) that 95% of HV underground cable installations also have LV underground cables in the same trench or easement. For this reason, the HV underground route line length is calculated by multiplying 5% to the HV underground circuit length for both urban and rural feeders.

<u>Estimated Information</u>:

The data provided is estimated information due to the preparation approach outlined above. This is considered to be Management's best estimate based on the data available.