Ergon Energy
Basis of Preparation
Economic Benchmarking RIN

31 October 2019

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1.2 Compliance with AR RIN Requirements

All mandatory data entry fields shaded yellow, have been populated.

Ergon Energy confirms, as required by the AER in Box 1, Revenue Financial Reporting Framework of Appendix B, Instructions and Definitions that Revenues reconcile to the Direct Control Services revenues in Regulatory Accounting Statements as per the Annual Reporting Requirements (AER defined term) as submitted to the relevant regulator, for the year in question).

Direct Control Services, which were charged by Ergon Energy to customers (in accordance with the EB RIN instructions at Section 2: Revenue) have been reported as

- Standard Control Services (SCS): Network Services, DUOS (including cross boundary duos); Capital Contributions; and
- Alternative Control Services (ACS): Public Lighting, Connection services, Metering services, and Ancillary services.

Public lighting for the recovery of construction and maintenance costs for the 2018-19 regulatory year has been reported as an ACS (refer to the source and methodology for Revenue Grouping by Chargeable Quantity under heading DREV0112: Public Lighting).

Ergon Energy’s approved services are as per Attachment 13 (Classification of Services) of the Australian Energy Regulator Final Distribution Determination (AER FDD). This correlates to Distribution use of System charges and Capital Contributions for SCS and Other Revenue and Contributions for ACS as displayed in the regulatory accounting statements.

Revenue reported in prior regulatory accounting statements which is not a Direct Control Service charged by Ergon Energy to Customers include: profit or gross proceeds on sale of assets, interest received, shared assets revenue and Transmission use of System charges. Rather, they were specific reporting requirements of prior regulatory instruments.

‘Revenue from Unmetered Supplies’ is the same for template 3, table 3.1.1 (DREV0107) as for template 3, table 3.1.2 (DREV0205). Public lighting has been reported in variable (DREV0112) and has been excluded from ‘revenue from unmetered supplies’ (DREV0107). This is based on the interpretation of the definitions for unmetered supplies and customer numbers. The latter states public lighting connections are not to be counted when calculating the number of unmetered customers.

DREV01: Total revenue by chargeable quantity for 2018-19 is the Total SCS Revenue reported in Ergon Energy’s 2018-19 Annual Reporting RIN less Jurisdictional scheme amounts and TUOS revenue. The TUOS component of Cross Boundary Revenue is also excluded from the Total SCS Revenue (similar to 2017-18).

The total of revenues by chargeable quantity for these variables reconciles to the total revenues by customer class (DREV02).

‘Revenue from Unmetered Supplies’ is the same for template 3, table 3.1.1 (‘DREV0107) as for template 3, table 3.1.2 (DREV0205)

As confirmed by the AER on 1 October 2014, the following variables are not applicable to Ergon Energy and accordingly have not been populated:

- DREV0303 F-Factor [Victorian specific factor];
- DREV0304 S-Factor True up [Victorian specific factor capturing the close out of the old ESCV s-factor scheme].

Consistent with prior submissions and advice received by the AER on 22 September 2017, Ergon Energy has also not populated the variable ‘DREV0305 Other’ for 2018-19.

Ergon Energy notes that the AER has changed the variable numbers associated with this table in its revised templates for 2013-14 (consistent with 2018-19). Therefore, care should be taken when reviewing variable data for 2018-19 against submissions prior to 2013-14.

1.3 Sources

Source Data for Tables 3.1.1 & 3.1.2

For year 2018-19, data has been sourced from Ergons’ billing system PEACE. Monthly DMK billing reports, based on Statement of Charges monthly periods, are collated to provide actual data required. This data is then adjusted for Accrual data. DREV0203 and DREV0204: Data splitting High /Low voltage in table 3.1.2 is considered estimated.

Ergon Energy has sourced the Accrual data from the Ergon Energy’s Annual Reporting RIN’s for 2018-19.

For year 2018-19, Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to variables in Template 3, table 3.1.2, except for the high/Low voltage data which is still considered estimated-see above comment.

In addition to the calculations above DREV0201 – DREV0204 have been adjusted from a billed basis to an unbilled basis on a pro-rata basis.

The total at DREV02 must align with the total at DREV01. Therefore the total unbilled amount for DREV0201 – DREV0204 is equal to the total of DREV01 less DREV0205 and DREV0206 on an unbilled basis.

DREV0205 equals DREV0107, and DREV0206 equals the sum of DREV0111 and DREV0112.

The total unbilled amount for DREV0201 – DREV0204 is calculated and the difference between that and the billed amount for those variables is added as an adjustment amount to present those variables on an unbilled basis.

Source Data for Table 3.1.3

Incentive schemes applicable to Ergon Energy relate to the EBSS and STPIS schemes – commencing from 1 July 2010.

EBSS payments for performance during 2010-15 are a component of the building blocks set in the relevant AER distribution determination. The EBSS payment for 2018-19 has been sourced from the AER’s SCS PTRM handed down as part of the final determination.

STPIS reward / penalty payments are added to revenues during the annual Pricing Proposal approval process. The reward / penalty under the STPIS scheme has been based on the STPIS revenue adjustment included in the TAR formula in the 2018-19 Pricing Proposal.

1.4 Methodology

Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in template 3, table 3.1.1.

Table 1-1 Mapping of DCOS to RIN Variable below sets out the mapping of Distribution Cost of Supply (DCOS) model charges to RIN variables.

Table 1-1 Mapping of DCOS to RIN Variable

DCOS model or Billing reference	Benchmarking RIN Variable
NDFC Network DUoS Fixed Charge$	Revenue from Fixed Customer Charges

NDFCG Network DuoS Fixed Charge Generation$	
NDCUC Network DUoS Connection Unit Charge$	
NDKVACC Network DUoS kVA Capacity Charge$	Revenue from Contracted Maximum Demand Charges
NDTDC Network DUOS Threshold Demand Charge$	
NDDCOP Network DUoS Demand Charge - Off Peak$	
NDDCP Network DUoS Demand Charge - Peak$	
NDKVAADC Network DUoS kVA Actual Demand Charge$	Revenue from Measured Maximum Demand Charges
NDERPC Network DUoS Excess Reactive Power Charge$	
NDVC Network DUoS Volume Charge$	Revenue from Energy delivery charges where time of use is not a determinant
Residential and Business Inclining Block Tariff Band1$	
Residential and Business Inclining Block Tariff Band2$	
Residential and Business Inclining Block Tariff Band3$	
NDVCOP Network DUoS Volume Charge - Off	Revenue from Off–Peak Energy Delivery charges

Peak$	
NDVCP Network DUoS Volume Charge - Peak$	Revenue from On–Peak Energy Delivery charges
NDVCS Network DUoS Volume Charge - Shoulder$	Revenue from Shoulder period Energy Delivery Charges

Methodology for DCOS specific issues

Revenue from controlled load customer charges (DREV0106), DREV0112 and Revenue from unmetered supplies (DREV0107) are inclusive of Fixed Charges and Volume charges i.e.: these charges haven't been separately reported in Revenue from Fixed Customer Charges (DREV0101) or Revenue from Energy Delivery charges where time of use is not a determinant.

For Revenue from Contracted Maximum Demand charges (DREV0108) and Revenue from Measured Maximum Demand charges (DREV0109), Ergon Energy has allocated the 'full recovery of revenue from customers on the SAC – Large tariff to Contracted Demand. Revenue from Demand component of Seasonal Time of Use Demand tariffs has also been allocated to Contracted Demand. Ergon Energy has adopted this approach as it is consistent with the approach used for Template 3.4 Operational data, 'Demand supplied' where instructions state, 'where Ergon Energy cannot distinguish between contracted and measured Maximum Demand, demand supplied must be allocated to contracted Maximum Demand.

Methodology for Table 3.1.1 & 3.1.2

Revenue from Public Lighting (DREV0112) has been reported as either ACS or SCS based on its service classification for the regulatory control period.

Variables (DREV0101 - DREV0109, and DREV0112) have been adjusted from the billed amounts (with the basis above) to an unbilled basis. The adjustment is an alignment with the reporting in Ergon Energy's 2018-19 Annual Reporting RIN. The total at DREV01 using AR RIN (on an unbilled basis) is higher than the sum of the variables using the billed basis. The difference has been allocated on a pro rata basis over the variables listed above.

DREV0110 - Metering Charges:

- SCS is zero for 2018-19. All Metering is ACS in 2018-19.
- ACS for 2018-19. The revenue is taken directly from the Income Statement in Ergon Energy's 2018-19 Annual Reporting RIN.

DREV0111 - Connection Charges:

- SCS for 2018-19. This revenue is taken directly from the Income Statement in Ergon Energy's 2018-19 Annual Reporting RIN. It is the Contributions in SCS.
- ACS for 2018-19. This revenue is taken directly from the Income Statement in Ergon Energy's 2018-19 Annual Reporting RIN. It is the total of the Connection services column.

DREV0112 - Public Lighting:

- SCS for years 2018-19. Ergon Energy has sourced information from PEACE monthly billing reports.
- ACS for 2018-19. The revenue has been taken directly from the Income Statement in Ergon Energy's 2018-19 Annual Reporting RIN. It is the total of the Public Lighting column.

DREV0113 - Revenue from Other Sources:

- SCS, nothing to report.
- ACS for 2018-19. The revenue has been taken directly from the Income Statement in Ergon Energy's 2018-19 Annual Reporting RIN. It is the total of the Ancillary network services column.

Variables DREV0110, DREV0111, DREV0112 (ACS), DREV0113, and DREV01, are derived from Ergon Energy's 2018-19 Annual Reporting RIN. No adjustment is required for an unbilled basis, as the AR RIN has been prepared on an unbilled basis. Variable DREV0112 (SCS) has been adjusted from a billed basis to an unbilled basis.

Capital Contributions have been recorded as 'Revenue from Other Customers' in Table 3.1.2 'Revenue grouping by customer type or class' as opposed to the customer type variables set by the AER. Unlike DUOS revenue which can be allocated to customer type variables based on network tariff codes (refer above); Contributions don't have a secondary system to verify the customer classes to allow mapping to these categories. Therefore, Ergon Energy has adopted the approach in the Instructions and Definitions document which states:

- Revenues that Ergon Energy cannot allocate to the customer types DREV0201–DREV0205 must be reported against 'Revenue from other Customers' (DREV0206).

Methodology for Table 3.1.3

The STPIS reward (DREV0302) has been calculated based on data in the TAR formula in the 2018-19 Pricing Proposal. Consistent with advice received from the AER on 14 September 2017, to reflect Ergon Energy's underlying performance results data has been based on STPIS reward implicitly included in revenues for pricing (i.e. s factor prior to removing prior year s factor impact).

The EBSS payment (DREV0301) has been calculated based on data in the AER's Final Determination SCS PTRM. This was the PTRM used to set prices from 2018-19.

The EBSS payment has been reconciled against data included in Attachment 1 of the AER's final determination.

1.5 Assumptions

No assumptions were made.

1.6 Estimated Information

DREV0203 and DREV0204: Data splitting High /Low voltage in table 3.1.2 is considered estimated. Also refer to Section 2 BOP 3.1.2 Revenue Grouping by Customer Type Or Class.

1.7 Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

Ergon Energy commenced accrual accounting for Network charges in 2013-14, and continued in 2018-19. The impact of the change is a 0.7% increase to DREV01.

As per AASB 118 Revenue; Ergon Energy commenced accrual accounting for unbilled network charges in 2013-14 and continued in 2018-19. Template 3.1, Table 3.1.2 has been prepared on an unbilled basis for 2018-19. The impact of the change is a 0.7% increase to DREV02.

No accounting policies adopted by Ergon Energy have materially changed during any of the Regulatory Years covered by the Notice, in relation to variables contained in template 3.1, table 3.1.3.

AASB 15 Revenue from Contracts with Customers has replaced AASB 118 Revenue.

See Note 1(c) Changes in accounting policies in the statutory accounts (an extract is below)

- *There were no changes to the revenue recognition policies for the major income streams (Network Use of Systems (NUOS) revenue, retail energy sales, sale of goods, the majority of contracts for services, operation, maintenance and construction of network assets and the non-refundable capital contributions) as a result of the requirements of the new standard.*
- *Contract assets and contract liabilities have been recorded on the statement of financial position in accordance with the standard. The revenue streams impacted by the new*

standard included a selection of the construction and service contracts as detailed below and further in Note 2.

- Refer to Note 2 in the Statutory accounts for more detail.

2 BOP 3.1.2 Revenue Grouping by Customer Type or Class (Estimated)

2.1 Scope of BOP

2.1.1 Table 3.1.2 Revenue Grouping by Customer Type or Class

2.2 Compliance with AR RIN Requirements

Distribution Loss Factor is allocated to all connections based on where they sit in the network. This data is used in actual billing.

2.3 Sources

Data Source is PEACE monthly billing reports which include allocated Distribution Loss Factors

2.4 Methodology

For 2018-19, Ergon has used the allocated Distribution Loss Factor to distinguish connections between High and Low voltage, as it believes it is more accurate than previous system. It is also easily repeatable and consistent year to year.

Previously Ergon assigned all SAC Level customers to Low Voltage except for a set of customers that were previously assigned to a now defunct tariff of SAC Demand High Voltage. We were therefore unable to identify any new connections at High Voltage.

Monthly billing reports are summed by Distribution Loss Factors, LV Bus and LV Line levels to Low Voltage

2.5 Assumptions

Ergon has assumed there are very few connections in the range 415v to 1,000v.

2.6 Estimated Information

Ergon Energy defines Low voltage below 1,000v; this report defines Low voltage as 415v or below.

Ergon Energy does not have systems which can relate billing system data to actual voltage level (i.e. which distinguishes between 415v and up to 1,000v). We have used allocated Low Voltage Distribution Loss Factor as there will be very few (if any) connections between 415v and 1,000v

2.7 Explanatory Notes

Ergon Energy is working to identify and quantify connections between 415v to 1,000v for future reporting

3 BOP - 3.2 Operating Expenditure

3.1 Scope of BOP

3.1.1 Table 3.2.1 Current opex categories and cost allocations

3.1.2 Table 3.2.2 - Opex consistency - current cost allocation approach

3.2 Compliance with AR RIN Requirements

Variables DOPEX0101 – DOPEX0110 (and subsequently, total DOPEX01) are considered mandatory and have been populated.

Variables DOPEX0101 – DOPEX0103 have been assigned a category name. Variable DOPEX0104—DOPEX0110 represent additional variables (rows) inserted for other Opex categories as required by Ergon Energy and allowed for under the RIN Instructions and Definitions.

Ergon Energy confirms, as required by AER in Box 2, Reporting Framework – Table 3.1.1 Current Opex categories and allocations in its Instructions and Definitions that Opex has been prepared in accordance with Ergon Energy current approved AER Cost Allocation Method (CAM). Directions within the Annual Reporting Requirements for the most recently completed RIN as submitted to the AER have been applied.

Opex has been reported in accordance with the categories required by the AER's RIN.

Ergon Energy does not currently own, control or operate any dual-function assets for inclusion in Opex. Ergon Energy does not have any subsidiaries which provide operating and maintenance services to the DNSP therefore reporting of margins are not applicable.

Where relevant (namely, during the current regulatory control period), total Opex equals that reported against the Annual Reporting Requirements (AER defined term) provided to the AER.

Variables DOPEX0201 – DOPEX0206 are considered mandatory, and have been populated.

Ergon Energy confirms, as required by the AER in Box 4, Reporting Framework – Table 3.2.1 Opex Consistency - Current Cost Allocation Approaches in its Instructions and Definitions that Opex has been prepared for the 2018-19 financial year in accordance with Ergon Energy's current AER CAM. For clarity, the AER Classification of Services per the current regulatory control period (2015-20) as referenced in that CAM have been applied for Opex tables 3.2.2

Opex has been reported in accordance with the categories required by the AER's RIN.

Opex for transmission connection point planning is considered a Network Service as it is an activity involved in planning the network. This amount has not been included under variable DOPEX0201:

Opex for network services however has been included separately in variable DOPEX0206: Opex for transmission connection point planning, resulting in only one count of this amount in Table 3.2.2.

As Ergon Energy does not currently own, control or operate any dual-function assets, there is no associated Opex to report. Ergon Energy does not have any subsidiaries which provide operating and maintenance services to the DNSP therefore reporting of margins are not applicable.

3.3 Sources

Ergon Energy has sourced the data used to populate template 3.2, table 3.2.1 and table 3.2.2 from the Ellipse general ledger for the current year.

3.4 Methodology

Using codes contained within the Ellipse General Ledger mapped to AER reporting categories, for example: Activity 52130 (Preventative Meters) is mapped to variable Preventive Maintenance. This is the same mapping process adopted for reporting the Annual Reporting RINs.

Ergon Energy extracted the Ellipse Trial Balance, created a Table containing mappings between the Ellipse Activities and product codes to the EB RIN Variables (DOPEX0201 - DOPEX0206) and a query was run to extract costs against relevant variables. Previous year's figure reported in ACS column for Network Services (DOPEX0201) represented ancillary service costs, this year's figure has been removed as it does not meet the definition of Network Services..

Ergon Energy extracted the Ellipse Trial Balance, created a Table containing mappings between the Ellipse Activities and product codes to the EB RIN Variables (DOPEX0201 - DOPEX0206) and a query was run to extract costs against relevant variables. From 2018-19 Ergon Energy recognised the item "Not Proceeding Network Initiated Capital Works" as "Other" in table 8.1.1.2. Also refer to Annual Reporting RIN T8.1 Income Statement BOP.

Transmission Point Planning contained in template 3.2, table 3.2.2.

Actual Information for DOPEX0206 Opex for transmission connection point planning has been prepared using actual hours worked and the number of staff involved in meetings to arrive at on costs, and travel and accommodation costs.

3.5 Assumptions

No assumptions were made.

3.6 Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) for 2018-19 in relation to all variables

3.7 Explanatory Notes

The AER approved Ergon Energy's CAM in July 2014, effective from the 1 July 2015, introducing changes compared to the prior CAM primarily for the following:

- Reclassification of services (AER FDD Attachment 13) from SCS to ACS, predominately for Real Estate Developments and Type 5 & 6 Metering; and
- Redundancies are recognised as Regulated Opex costs.

The AER approved a subsequent change to Ergon Energy's CAM in November 2018, effective from the 1 December 2018, for a change in circumstance for corporate and organizational structure, and the accountability for the CAM. The methodologies for attributing and allocating costs remained unchanged.

4 BOP 3.2.4 - Opex for High Voltage Customers

4.1 Scope of BOP

4.1.1 Table 3.2.4 – Opex for High Voltage Customers

4.2 Compliance with AR RIN Requirements

DOPEX0401 is considered a mandatory variable and has been populated.

It is noted that data in this table will not reconcile to information reported in response to Annual Reporting RINs provided by Ergon Energy, as we do not capture costs in relation to distribution transformers owned by HV customers.

4.3 Sources

Ergon Energy has sourced the data from Ellipse using Ellipse Financials reflected into CA RIN Template 2.8 2018-19 for actual costs for distribution maintenance.

Variable DPA0502: Distribution transformer capacity owned by High Voltage Customers (MVA) was also used in arriving at an estimate (refer to Table 3.5.2 Transformer Capacities Variables for a detailed explanation of the source for the data).

4.4 Methodology

Refer response to below, which details the methodologies applied to provide Estimated Information including assumptions made.

4.5 Assumptions

No assumptions were made.

4.6 Estimated Information

Accordingly, Ergon Energy has provided 'Estimated Information' (as per the AER's defined term) in relation to DOPEX0401 - Opex for High Voltage Customers.

On page 22 of the Instructions and Definitions document issued by the AER in November 2013, it states

"When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if Ergon Energy can provide Actual Information for the Variables in Table 3.4 [renamed table 3.2.4] it must do so; otherwise Ergon Energy must provide Estimated Information."

As required by the AER's instructions and definitions, DOPEX0401 was estimated based on the Opex Ergon Energy incurs for operating similar Megavolts-ampere (MVA) capacity Distribution Transformers within its own network.

The total annual cost of maintenance for distribution transformers (owned by Ergon Energy) was obtained for 2018-19 from Ellipse. The total annual maintenance cost for distribution transformers owned by Ergon Energy was then multiplied by the percentage of Ergon Energy's distribution transformers greater than 500kVA capacity to obtain the annual maintenance cost of >500kVA transformers owned by Ergon Energy. The annual maintenance cost of the >500kVA transformers owned by Ergon Energy was then divided by the total MVA of the >500kVA transformers owned by Ergon Energy to give the per-MVA cost of maintaining Ergon Energy owned transformers >500kVA.

There are no customers below 500kVA and connection policies have freed up conditions regarding HV customers such that some are now connected with as low as 500kVA capacity requirements, versus a previous minimum of 1,000kVA, making 500kVA a suitable delineating point. Therefore, the cost of maintenance for Ergon Energy's transformers above 500kVA was calculated. HV Transformer capacity owned by Customers (MVA) was multiplied by the per-MVA cost ($/MVA) of maintaining Ergon Energy owned transformers > 500kVA to provide an estimate of the cost of maintaining the distribution transformers owned by customers. Base year for Distribution Transformer numbers is 2018-19.

4.7 Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

Changes in accounting policies adopted by Ergon Energy are not relevant to costs incurred in relation to external customers, other than in relation to components of data being utilised for the estimate provided (that is, Opex).

Costs have been presented on a current cost approach basis in that it is consistent with the most recent Annual Reporting Requirements and the 2018-19 allocation of costs in the CAM.

5 BOP - 3.2.3 Provisions

5.1 Scope of BOP

5.1.1 Table 3.2.3 - PROVISIONS

5.2 Compliance with AR RIN Requirements

Variables considered mandatory have been populated, relative to each Provision.

Ergon Energy confirms, as required by the AER in Box 6, *Reporting Framework for Provisions* in its RIN Instructions and Definitions, that provisions are reported in accordance with the principles and policies within the Annual Reporting Requirements (AER defined term) for the Regulatory Year.

Furthermore, financial information on provisions reconciles to the reported amounts for provisions in the annual RIN or Regulatory Accounts information provided to the AER.

Ergon Energy notes that the AER has changed the variable numbers associated with this table in its revised templates in the past. While this is the same format as 2013-14, care should be taken when reviewing variable data for 2018-19 against prior submissions.

5.3 Sources

Data has been sourced from the Ergon Energy general ledger.

5.4 Methodology

The balances in L3600 - Restructuring, L3800- Long Service Leave, L3810 Annual Leave, L3820 Vested Sick Leave, L7000 Prov for Long Service Leave NC and L7010 Prov for Annual Leave NC will now be swept to EQLD on a monthly basis via a reversing accrual journal. We will continue to report on these activities in this and future EB Provision submissions to reflect the movements in these activities.

As discussed with the AER - On 1 July 2019, employees of the distribution network service providers Ergon Energy and Energex where transferred to Energy Queensland Limited (EQL) as the parent entity of the Energy Queensland Limited corporate group. EQL has entered into the Service agreement with Ergon Energy and Energex which effectively provides Energex and Ergon Energy with a labour resource and this is subject to the direction and management of the DNSP's. Therefore, labour provided under the EQL service agreement is reported as in-house/internal labour, and not reported as outsourced labour. Furthermore, employee related provisions no longer reside with the DNSP's – they reside with EQL. Balance sheet balances were transferred to EQL on 30 June 2019.

The closing balance of employee related provisions is therefore zero. The transfer to EQLD has been reflected in 'unused amounts reversed during the period-other component'. It is noted that movement in provisions is reflective of EQL employees whose payroll was processed in the Energex/Ergon Energy ERP system. The movement in the EQL provisions (which represents employees whose payroll was processed in the EQL ERP system) has been apportioned between the two DNSP's on a 50/50 basis in line with how EQL were allocated to the DNSP's.

(1) The Restructure Provision has been calculated on the following basis:

Increases to the Restructure Provision are deemed to be the redundancy provision of employees who are expected to leave the company on a voluntary redundancy basis

Used is deemed to be the redundancy provision for those employees whose employment with the organisation has been terminated and a redundancy payment has been made to the employee

Redundancy provision calculations are provided by Human Resources

The SCS portion is based on the service classifications split of the asset base.

(2) The Employee Benefit Provision and the Annual Leave Provision and the Super on Employee Entitlements Provision have been calculated using the credit values appearing on the Ellipse transaction listing as increases to the provision and using the debits on the Ellipse transaction listing as used.

The SCS portion is based on the service classifications split of the asset base, then split between Opex and Capex using the actual Opex/Capex spend per the general ledger.

(3) The Rehabilitation Provision has been split as per classification of individual sites, i.e. regulated sites and non-regulated sites. The value of the movement has been allocated 100% to OPEX and nil to CAPEX to correctly reflect the activities used in the journal entries. If the movement in the Rehabilitation provision was due to Revalued assets, (i.e. posted to Asset Revaluation Reserve) this is classified as Other.

Unused amounts reversed during the period is calculated by taking the write back provisions (to opex) figure from the Rehabilitation TAB within the provisions workings workbook.

(4) Vested Sick Leave is for control room employees only, therefore classified as SCS Opex.

The Vested Sick leave Provision has been calculated using the credit values appearing on the Ellipse transaction listing as increases to the provision and using the debits on the Ellipse transaction listing as used. Adjustments are then applied to these values based on the increase during the period in the discount amount arising from the passage of time and the effect of any change in the discount rate.

(5) The Long Service Leave Provision has been calculated using the payroll entries which represent leave taken by employees- these appear as debits on the Ellipse transaction listing as ‘OR’ in reference 4. These transactions are deemed to be used. The balance is then split between the time value of money and the increases derived from the Ellipse transaction listing. The time value of money is derived from the Long Service Leave calculation model using the corporate bond rates and then the corporate bond rates are removed to derive the undiscounted value. The time value is then the movement from 30 June last year to 30 June this year.

5.5 Assumptions

The difference in PP&E allocation percentages between the current regulatory year and prior regulatory year is treated as follows:

- adjustments that resulted in increased provisions are assumed to be additions to provisions; and
- adjustments that resulted in decreased provisions are assumed to be unused amounts reversed.

5.6 Estimated Information

Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in template 3, table 3.2.3 – Provisions.

5.7 Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

There were no changes in accounting policies impacting Provisions during the 2018-19 year.

6 BOP - 3.3 Assets (RAB)

6.1 Scope of BOP

6.1.1 Table 3.3.1 - REGULATORY ASSET BASE VALUES

6.1.2 Table 3.3.2 - ASSET VALUE ROLL FORWARD

6.1.3 Table 3.3.3 - TOTAL DISAGGREGATED RAB ASSET VALUES

6.1.4 Table 3.3.4 - ASSET LIVES

6.2 Compliance with AR RIN Requirements

Asset Value Roll Forward – SCS and ACS

Ergon Energy confirms, as required by the AER in Box 7, *Assets (RAB) Financial Reporting Framework* in Appendix B, Instructions and Definitions, that:

- Wherever possible, RAB financial information (capex, disposals and inflation) for SCS and ACS reconciles to decisions the AER has made in relation to RAB values for these services through the 2010-15 Ergon Energy Distribution Determination and in the 2015-20 Ergon Energy Final Determination; and
- Where forecast values (additions and disposals) were used in relation to a decision on RAB values (in the 2005-10 Distribution Determination and the 2010-15 Distribution Determination), these amounts have been replaced with actual values which reconcile to amounts reported in Regulatory Reporting Statements (RRS) for 2009-10 (i.e. additions for the last year of the previous regulatory period) and the Annual Performance RIN for 2014-15.

In accordance with the AER's email of 7 September 2016, Ergon Energy has deviated from the RIN requirements by reporting forecast straight line depreciation, based on:

- The SCS and ACS capex approved by the AER in the 2015-20 Final Distribution Determination;
- The opening RAB for SCS and ACS approved by the AER in the 2015-20 Final Distribution Determination, adjusted to recognise 2014-15 actual capex and disposals;
- The remaining lives for SCS and ACS approved by the AER in the 2015-20 Final Distribution Determination, adjusted to recognise the 2014-15 actual capex and disposals.

For the purposes of reporting regulatory depreciation (which for 2018-19 is the sum of straight line depreciation and inflation of the 2018-19 opening RAB), Ergon Energy has reported:

- Actual inflation on the opening RAB for 2018-19 (using the actual inflation values for 2018-19 based on the Dec - Dec Weighted Average of 8 capital cities as published on the Australian Bureau of Statistics Website)

- Straight line deprecation for 2018-19, escalated by actual inflation in 2018-19 to bring the depreciation into nominal terms

As such, the reported regulatory depreciation value in the T3.3 EB RIN Template is the sum of the actual inflation of the opening RAB for 2018-19, and the forecast straight line depreciation for 2018-19.

Ergon Energy has adopted the *Standard Approach*, with *Direct Attribution to the AER's economic benchmarking RAB Asset Classes*, as described in section 4.1.1 of Appendix B, Instructions and Definitions. For some non-system assets to the AER's 'other long life assets' and 'other short life asset categories' their categorisation has been ascertained by using additional Ellipse source system extracts (additions report). This is discussed further in the table, in section C below.

- RAB Asset Financial Information for remaining asset classes has been directly allocated into RAB Asset categories in accordance with definitions provided in chapter 9 of the Appendix B, Instructions and Definitions (Refer to Section C below). RAB values for each of the RAB Asset categories are exclusive of Capital Contributions. Total capital contributions for each relevant regulatory year are provided at DRAB13

- Ergon Energy currently does not own, control or operate any Dual Function Assets

- Although Variable Codes DRAB0801 – DRAB0807 in relation to RAB Asset 'Easements' are shaded orange, to allow for blacked out data input, these cells have been populated. Ergon Energy has the ability to report Easements, and necessarily they are not included in the remaining categories.

In accordance with the instructions and definitions, Ergon Energy has only included RAB values for those services where the AER has approved a RAB or RAB equivalent. Therefore, for ACS, Ergon Energy has only reported RAB assets that provide ACS Street lighting Services and Type 5-6 Metering Services, consistent with the classification of service, and the RAB that was approved for these categories of service in Ergon Energy's 2015-20 Distribution Determination. No RABs have been approved for any of Ergon Energy's other categories of ACS (Quoted and Fee Based Services).

Annual Value Roll Forward – Network Services

Ergon Energy has prepared the information for the Network Services RAB in accordance with the definition of Network Services set out in Appendix B, Instructions and Definitions. Further detail on how the information provided by Ergon Energy is consistent with the requirements and definitions of Network Services is discussed below.

Total disaggregated RAB asset values – Capital contributions

As all data entry fields are shaded yellow, indicating mandatory data input fields, all cells have been populated.

RAB values for each of the SCS RAB Asset categories in the worksheet are exclusive of Capital Contributions. Ergon Energy notes the value provided at DRAB13 is the total value, for “estimated value of capital contributions or contributed assets” for each relevant regulatory year.

Asset Lives – Estimated Service Life of New Assets

All data entry fields are shaded yellow, indicating mandatory data input fields and accordingly, have been populated.

Asset lives reported, are estimated service lives of new assets installed during the regulatory reporting year

Asset Lives – Estimated Residual Service Life

All data entry fields are shaded yellow, indicating mandatory data input fields and accordingly, have been populated.

Asset lives reported, are estimated service lives of new assets installed during the regulatory reporting year

6.3 Sources

Asset Value Roll Forward – SCS and ACS

For 2018-19, annual SCS and ACS (street lighting and Type 5-6 metering) financial information (additions, disposals and capital contributions) are sourced from the 2018-19 AER Annual Reporting RIN provided by Ergon Energy to the AER.

Consistent with the AER’s Final Distribution Determination, from 2015-16 onwards capex recognised in the SCS RAB and therefore reported in the T3.3 RIN Template is exclusive of capital contributions.

For each year from 2010-11 to 2013-14, the RAB financial information for SCS and ACS reconciles to decisions the AER has made in relation to RAB values for these services through the 2010-15 Ergon Energy Distribution Determination and in the 2015-20 Ergon Energy Final Determination.

In accordance with the guidance provided by the AER in its email of 7 September 2016 to Ergon Energy, the 2014-15 estimated financial information contained within the AER's 2015-20 final Distribution Determination has been replaced with actual financial information for 2014-15 as reported in the 2014-15 Annual Performance RIN. This means that closing RAB as at 30 June 2015, as reported in Template 3.3 of the Economic Benchmarking RIN, will not align with the opening RAB value for 1 July 2015 as approved by the AER in its 2015-20 final Distribution Determination.

Similarly, the 2009-10 estimated financial information contained within the AER's 2010-15 final Distribution Determination has been replaced with actual financial information for 2009-10 as reported in the 2009-10 RRS. The closing RAB values for each year from 1 July 2010 onwards will also not align with the closing RAB values calculated each year in the AER's 2010-15 RFM. This is because the AER's 2010-15 RFM recognises actual 2009-10 additions and disposals for the first time at the end of 2014-15, whereas in the T3.3 RIN template the actual 2009-10 additions and disposals is recognised in the year in which it is incurred, and rolled forward through to 1 July 2015.

Annual Value Roll Forward – Network Services

As defined by the AER for the purposes of the Economic Benchmarking RIN, Network Services are a subset of SCS excluding Connection Services, Type 5-7 Metering Services, Fee Based and Quoted Services and Street Lighting Services. In the case of Ergon Energy, consistent with the AER's definition of Network Services, we assume it is also necessary to exclude gifted assets (since these are all related to connection services) and also any assets included in the Network Services category that are not funded by Ergon Energy i.e. Network Services funded via capital contributions.

Network Services data is derived from SCS data, which for 2010-11 to 2013-14 is aligned with the financial information (additions and disposals) used in the AER's Final Distribution Determination RFM (as discussed in the previous section above). 2014-15 to 2018-19 SCS actual additions and disposals are sourced from the 2014-15 to 2018-19 AER Annual Reporting RINs respectively, provided by Ergon Energy to the AER.

Consistent with the SCS RAB values reported in the T3.3. RIN Template, the reported actual SCS additions used in calculating the Network Services net capex for the 2018-19 regulatory year are consistent with the SCS values in the 2018-19 Annual Reporting RIN, adjusted for movements in provisions and shared asset usage.

Connection Services data is captured within the Ergon Energy "Connections" expenditure category. For 2018-19, the annual Connections expenditure values are sourced from the 2018-19

AER Annual Reporting RIN provided by Ergon Energy to the AER. Specifically, Connections expenditure includes:

- New shared network assets for Standard Asset Customers (i.e. small domestic, rural and customer customers);
- New dedicated connection assets for Standard Asset Customers; and
- Testing and commissioning of all new shared network assets and connection assets for Standard Asset Customers only.

It explicitly excludes metering expenditure, connection expenditure for real estate developers and design, construction, test and commission costs for large commercial and industrial customers.

As indicated above, Connections expenditure incorporates a portion of shared network expenditure (either funded by Ergon Energy or funded via capital contributions). To be consistent with the AER's definition of Network Services, we assume it is necessary for any Ergon Energy-funded shared network to be reported in the Network Services category, but any gifted assets and shared network not funded by Ergon Energy to be excluded. In order to derive the net value of shared network expenditure to be included in Network Services (and hence, the value of Connections expenditure to be removed from the SCS asset additions), it is necessary to:

- Identify the total amount of Connections expenditure related to the shared network and to dedicated connection assets;
- Identify that portion of the Connections expenditure that is not funded by Ergon Energy (i.e. capital contributions).

The net result of the above (i.e. total Connections expenditure related to connection assets (i.e. not shared and not contributed by customers) represents that portion of Connections expenditure that is required to be removed from SCS asset additions in order to determine the amount attributable to Network Services.

Actual additions, disposals and capital contributions for 2018-19 associated with Street Lighting Services and Type 5-6 Metering Services (to be removed from SCS data and hence Network Services data) are sourced from Ergon Energy's 2018-19 Annual Reporting RIN templates.

No adjustment is necessary in relation to Fee Based and Quoted Services since this expenditure is already excluded from the SCS data (and hence Network Services data).

For 2018-19, the value of capital contributions (gifted assets and cash contributions) is sourced from the Ellipse General Ledger, and the 2018-19 Annual Reporting RIN.

To be consistent with the AER's definition of Network Services, expenditure related to Connection services (and Capital Contributions), Type 5-7 Metering Services and Street Lighting Services were either removed or already excluded from the SCS data.

Total disaggregated RAB asset values – Capital contributions

Data used to populate this table was extracted from the 2018-19 AER Annual Reporting RIN lodged by Ergon Energy to the AER.

Asset Lives – Estimated Service Life of New Assets & Estimated Residual Service Life

Data was sourced from Ergon Energy's fixed asset register. Asset lives in the fixed asset register are based upon engineering expectations and are reviewed on a regular basis.

6.4 Methodology

Asset Value Roll Forward – SCS and ACS

Template 3.3, table 3.3.1 (Regulatory Asset Base Values) requires Ergon Energy to report totals for RAB Financial Information for 2018-19, across Network Services, SCS and ACS.

Ergon Energy notes that variables DRAB0101 through DRAB0107 in table 3.3.1 represent RAB Financial Information for the total asset base. The RAB Financial Information for the total asset base is then further disaggregated into the lower level RAB Asset Categories for each category of service (SCS, ACS and Network Services) in table 3.3.2.

As Ergon Energy has addressed the Basis of Preparation requirements at the lower level RAB Asset Categories, it is implicit that Ergon Energy has also addressed the minimum requirements for template 3.3, table 3.3.1. This is because all of the RAB values set out in template 3.3 have been calculated using a common Roll Forward Model (RFM) for each category of service (SCS, ACS and Network Services). As a result, the RAB values reported for the total asset base in table 3.3.1 will be consistent with the RAB values reported at the lower level RAB Asset Categories in table 3.3.2 for each category of service.

As noted above, Ergon Energy has with the exception of opening and closing RAB values;

- Aligned actual financial information in the T3.3 template with that in the AER's 2015-20 Final Distribution Determination for Ergon Energy;
- Replaced all estimated financial information previously reported in Template 3.3 and in the AER's 2015-20 Final Distribution Determination for Ergon Energy with actual values;

- Reported actual additions, disposals and capital contributions for the 2018-19 regulatory year consistent with that in the 2018-19 Annual Reporting RIN, with additions adjusted for movements in provisions and shared asset usage. There were Nil ACS disposals in 2018-19.

In doing so, the opening and closing RAB values for SCS will not align with the corresponding RAB values in the AER's Final Determination RFMs.

The methodology Ergon Energy applied for each of these steps listed above is set out below:

- Roll forward mechanism – Consistent with the roll forward mechanism approved by the AER in the 2015-20 Final Distribution Determination, Ergon Energy has rolled forward the 1 July 2010 SCS RAB in two separate RFMs:

    A "legacy" SCS RFM which rolled forward those assets installed prior to 1 July 2010

    A "capex" SCS RFM which rolled forward those assets installed on or after 1 July 2010

- Ergon Energy has used the AER's RFM workbooks to perform the RAB roll forward to perform the RAB roll forward across multiple regulatory control periods, separate RFMs have been used for each regulatory control period and for each form of control. The complete set of RFMs for SCS are listed below:

    2005-10 RFM for SCS

    2010-15 RFM Legacy for SCS

    2010-15 RFM Capex for SCS

    2015-20 RFM Legacy for SCS

    2015-20 RFM Capex for SCS

    2005-10 RFM for ACS

    2010-15 RFM for ACS

    2015-20 RFM for ACS

Ergon Energy has largely retained the structure and calculations within the AER's RFMs without modification yet allowing for an annual change in WACC for the trailing cost of debt, and the use of forecast regulatory depreciation as reflected in the functionality of the AER's roll forward model version 2 published on the 15 December 2016. Ergon Energy has maintained its suite of models established in 2015-16 for reporting 2018-19 RAB values due to this alignment. Additionally, it was found in performing modelling using RFM version 2 resulted in some asset categories over depreciating at the end of their useful life when the forecast depreciation switch was applied. This is exacerbated for Ergon Energy as legacy models were established that contain asset categories with remaining lives < 5years. Until the error in functionality in the version 2 model is corrected, Ergon Energy will maintain its current suite of models. Additionally, the following changes have been made to enable the roll forward across multiple regulatory control periods for the purposes of populating the T3.3 template.

Additions, Disposals and Capital Contributions

- 2009-10 actual additions and disposals for SCS and ACS are entered in the 2005-10 RFM for SCS and 2005-10 RFM for ACS respectively. These replace the estimates for 2009-10 which were included in the AER's approved SCS RFM and Public Lighting RFM for the 2010-15 Final Distribution Determination. Consistent with the transitional arrangements at the time, capital contributions are not entered in the 2005-10 RFM for SCS

- Actual SCS additions and disposals (with disposals reported on a NBV basis) for 2010-11 to 2013-14 inclusive are entered in the 2010-15 Capex RFM for SCS. These values are consistent with those in the AER's SCS Capex RFM model approved for the 2015-20 Final Distribution Determination for Ergon Energy. Consistent with the transitional arrangements at the time, capital contributions are not entered in the 2010-15 RFM for SCS. No additions, disposals or capital contributions for 2010-11 to 2013-14 inclusive are entered into the 2010-15 Legacy RFM for SCS

- The term disposal value is not defined in the NER, however the AER considered that using the sale or depreciated value as the disposal value was acceptable in the AER's RFM Final Decision for Electricity Distribution Network Service Providers (June 2008). Ergon Energy adopted the sale value in its Regulatory Proposal to the AER for the 2015-20 regulatory control period, accepted by the AER. This is a change to the previous Regulatory Control periods approach using depreciated value.

- Actual Public Lighting ACS additions, disposals and capital contributions for 2010-11 to 2013-14 inclusive have been included in the 2010-15 RFM for ACS. These values are consistent with those in the AER's Public Lighting RFM model approved for the 2015-20 Final Distribution Determination for Ergon Energy

- 2014-15 actual additions and disposals for SCS and ACS (as well as ACS Public Lighting capital contributions) are entered into the 2010-15 Capex RFM for SCS and the 2010-15 RFM for ACS respectively. These replace the estimates for 2014-15 which were included in the AER's approved SCS Capex RFM and Public Lighting RFM for the 2015-20 Final Distribution Determination. No additions, disposals or capital contributions for 2014-15 are entered into the 2010-15 Legacy RFM for SCS

- Actual 2018-19 additions and capital contributions for SCS and ACS (as well as SCS disposals) are included in the 2015-20 Capex RFM for SCS and 2015-20 RFM for ACS respectively. SCS additions have been adjusted to remove movements in provisions and shared asset usage. ACS actuals for 2018-19 include Public Lighting and Type 5-6 Metering additions, disposals and capital contributions which reflects the change of service classification for Type 5-6 Metering from SCS to ACS as of 1 July 2015. No SCS additions, or capital contributions are entered into the 2015-20 Legacy RFM for SCS

- Actual 2018-19 disposals for SCS are split between the 2015-20 Capex RFM for SCS and 2015-20 Legacy RFM for SCS, depending on when the disposed assets were originally purchased. Disposed assets purchased prior to 1 July 2010 are included in the 2015-20 Legacy RFM for SCS, and those purchased on or after 1 July 2010 are included in the 2015-20 Capex RFM for SCS.

Opening RAB Values

- The opening SCS RAB as at 1 July 2010 in the 2010-15 Legacy RFM for SCS is set equal to the closing RAB in the 2005-10 RFM for SCS as calculated in cells L359:L388 of the Total Actual RAB Roll Forward tab. Similarly, the opening ACS RAB as at 1 July 2010 in the 2010-15 RFM for ACS is set equal to the closing RAB in the 2005-10 RFM for ACS as calculated in cells L373 of the Total Actual RAB Roll Forward tab.

- This approach outlined in the previous bullet point differs from AER's RFM, which requires that the opening RAB, rather than the closing RAB, of the final year of the previous regulatory control period be entered. The reason Ergon Energy has deviated from the AER's RFM is to remove the need for the RFM to adjust for the difference between forecast and actual net capex in 2009-10. No adjustment is necessary as the actual 2009-10 additions and disposals are now available to be rolled into the RAB. However, this deviation and recognition of 2009-10 actuals in the opening 1 July 2010 RAB means that the opening and closing RAB values for SCS and ACS for 2010-11 onwards will not align with those in the AER's 2010-15 Final Distribution Determination RFMs.

- Consistent with the AER's 2015-20 Final Distribution Determination, the opening RAB in the 2010-15 RFM Capex for SCS is set equal to zero.

- The opening SCS RAB as at 1 July 2015 in the 2015-20 Legacy RFM for SCS is set equal to the closing RAB in the 2010-15 Legacy RFM for SCS as calculated in cells R359:R388 of the Total Actual RAB Roll Forward tab. These cells in the 2010-15 Legacy RFM for SCS apply the same adjustments to the 30 June 2015 RAB as the AER to remove the value of those assets shared in the provision of ACS services (for those services reclassified in the 2015-20 Final Distribution Determination from SCS to ACS).

- As noted above, the approach outlined in the previous bullet point differs from AER's RFM. There is no need for the RFM to adjust for the difference between forecast and actual net capex in 2014-15 as the actual 2014-15 additions and disposals are now available to be rolled into the RAB. However, this deviation and recognition of 2014-15 actuals in the opening 1 July 2015 RAB means that the opening SCS RAB values for 1 July 2015 do not align with those in the AER's 2015-20 Final Distribution Determination RFM for SCS.

- The opening SCS RAB as at 1 July 2015 in the 2015-20 Capex RFM for SCS is set equal to the closing RAB in the 2010-15 Capex RFM for SCS as calculated in cells R359:R388 of the Total Actual RAB Roll Forward tab. These cells in the 2010-15 RFM Capex for SCS apply the same adjustments to the 30 June 2015 RAB as the AER to remove the value of those assets shared in the provision of ACS services (for those services reclassified in the 2015-20 Final Distribution Determination from SCS to ACS).

- The opening ACS RAB as at 1 July 2015 in the 2015-20 RFM for ACS is set equal to the sum of the Type 5-6 Metering opening RAB value on 1 July 2015 as approved by the AER in the 2015-20 Final Distribution Determination, and the Public Lighting closing RAB in the 2010-15 RFM for ACS as calculated in cells L373 of the Total Actual RAB Roll Forward tab.

- As noted above, this approach outlined in the previous bullet point differs from AER's RFM. There is no need for the RFM to adjust for the difference between forecast and actual net capex in 2014-15 as the actual 2014-15 additions and disposals are now available to be rolled into the RAB. However, this deviation and recognition of 2014-15 actuals in the opening 1 July 2015 RAB means that the opening Public Lighting RAB values for 1 July 2015 do not align with those in the AER's 2015-20 Final Distribution Determination RFM for Public Lighting.

Straight Line Depreciation

Ergon Energy has reported straight line (and implicitly, regulatory depreciation) for 2018-19 as 'Actual Information'. This is because:

- The inflation of the opening RAB, which comprises part of the regulatory depreciation amount, is an actual value based on the escalation of the 2018-19 opening RAB by the actual 2018-19 inflation

- The forecast 2018-19 straight line depreciation, which comprises the remainder of the regulatory depreciation amount, is also considered to be 'Actual Information', because:

- The AER’s email of 7 September 2016 requires that Ergon Energy report straight line depreciation in accordance with that forecast by the AER for 2018-19 in its 2015-20 Final Distribution Determination.

- Ergon Energy has been directed by the AER to use forecast depreciation therefore there is no other valid alternative by which to report this information. Forecast depreciation is obtainable from the 2015-20 Final Distribution Determination, and the AER’s FDD RFM. It is a record used in Ergon Energy’s normal course of business for the purposes of reporting the RFM RAB that is not estimated or calculated by Ergon Energy as part of the EB RIN reporting process.

Of note, the 1 July 2015 Opening Asset Value included $8.09M in equity raising costs which is used to calculate the inflation addition and forecast depreciation amounts included in Table 3.3.1. In Table 3.3.2 the inflation addition and forecast deprecation amount for equity raising costs has been excluded as the nature of the cost doesn’t meet with asset class definitions for reporting this table. A difference arises between the opening and closing values as a result.

Other Matters

The above approach replaced previously reported RAB figures for SCS and ACS from 2009-10 to 2014-15 inclusive and by default has an impact on the Network Services RAB calculations. These updated values can be provided to the AER in a restated historical RIN submission, if required.

Ergon Energy asset categories (as reported in the SCS and ACS RFMs and Annual Reporting RIN’s) have been directly mapped to the required economic benchmarking RAB asset categories, with the exception of some non-network asset categories (see below).

For some non-network asset categories (buildings, motor vehicles and plant and equipment), the AER definitions require Ergon Energy to split assets between short and long-life assets categories. Ergon Energy does not report data on this disaggregated basis. However, asset additions are readily determined from the asset register along with their lives. This information was used to apportion the relevant opening balances, additions and disposals to the required short and long-life categories

Ergon Energy has apportioned total buildings, motor vehicles and plant & equipment attributable to short and long life categories on the basis of asset addition for each asset. Asset additions are readily determined from the asset register along with the associated asset lives. With motor vehicles (as an example) heavy vehicles and a % of total vehicle additions was determined. This was then used to split total vehicle Capex between short and long lives. The same process was used for buildings and for plant & equipment. RAB disposals are allocated between short and long lived assets based on asset additions to these categories.

Annual Value Roll Forward – Network Services

Ergon Energy provides the following explanation of how actual RAB values for network services are reported in Table T3.3 of the EB RIN:

- Roll forward mechanism – Consistent with the roll forward mechanism approved by the AER in the 2015-20 Final Distribution Determination, Ergon Energy has rolled forward the 1 July 2010 Network Services RAB in two separate RFMs:

    A "legacy" Network Services RFM which rolled forward those assets installed prior to 1 July 2010

    A "capex" Network Services RFM which rolled forward those assets installed on or after 1 July 2010

- Ergon Energy has used the AER's RFM workbooks to perform the RAB roll forward. To perform the RAB roll forward across multiple regulatory control periods, separate RFMs have been used for each regulatory control period and for each form of control. The complete set of RFMs for Network Services are listed below:

    2005-10 RFM for Network Services

    2010-15 RFM Legacy for Network Services

    2010-15 RFM Capex for Network Services

    2015-20 RFM Legacy for Network Services

    2015-20 RFM Capex for Network Services

- Ergon Energy has largely retained the structure and calculations within the AER's RFMs without modification, however the following changes have been made to enable the roll forward across multiple regulatory control periods for the purposes of populating the T3.3 template:

Additions, Disposals and Capital Contributions

- Network services additions for 2009-10 to 2014-15 inclusive are calculated using the same approach as documented in the Basis of Preparation for the 2014-15 EB RIN. However, the SCS additions for 2009-10 and 2014-15, which form part of calculation of the Network Services additions, are now recognised as actuals. For this reason, the opening and closing Network Services RAB values for each year from 1 July 2010 onwards will not align with the values reported in the 2014-15 EB RIN table T3.3

- Additions for Network Services for 2009-10 are entered into the 2005-10 RFM for Network Services. Actual disposals for 2009-10 are entered into the 2005-10 RFM for Network Services and are consistent with the SCS disposals values entered into the 2010-15 RFM Capex for SCS

- Additions for Network Services for 2010-11 to 2014-15 inclusive are entered into the 2010-15 RFM Capex for Network Services. Actual disposals for Network Services in 2010-11 to 2014-15 inclusive are entered into the 2010-15 RFM Capex for Network Services. The disposals values are consistent with the SCS disposals values entered into the 2010-15 RFM Capex for SCS. No additions or disposals are entered into the 2010-15 RFM Legacy for Network Services. Capital Contributions are not entered into the 2010-15 RFM Capex for Network Services or the 2010-15 RFM Legacy for Network Services

- Actual 2016-17 to 2018-19 additions and capital contributions are entered into the 2015-20 RFM Capex for Network Services and are calculated as follows:

SCS Total Capital Expenditure, less

SCS Total Disposals, less

SCS Total Capital Contributions, less

SCS LV services and meters, less

Connections Capital Expenditure (net of meters and LV Services) that is not attributable to the shared network, equals

Network Services Net Capital Expenditure

- The SCS Total Capital Expenditure, Total Disposals, Total Capital Contributions and LV services and meters is sourced from Ergon Energy's 2018-19 AR RIN Capex templates

- Connections Capital Expenditure is sourced from the general ledger, by asset class, from codes C2060 (domestic and rural connections), C2070 (small commercial and industrial connections) and C2080[1] (other) is pro-rated across both C2060 and C2070. Whilst these expenditures are exclusive of gifted assets and cash contributions, they are inclusive of both upstream shared network expenditure and dedicated connection asset expenditure.

- To identify the upstream shared network expenditure component, the following approach is taken.

- The LV Services and Meters asset classes are removed from both the C2060 and C2070 capital expenditures. This is because these asset classes are always 100% dedicated connection assets.
- Then, the percentage of dedicated connection assets obtained from a sample of domestic and rural and small commercial and industrial connection projects is applied to the C2060 and C2070 capital expenditures respectively. This gives an indication of the upstream shared network component of the Connection Capital Expenditure that must be included in the total Network Services Capital Expenditure.
- The remainder of the Connection Capital Expenditure, together with the LV Services and Meters capital expenditure, is the dedicated connection asset capital expenditure that must be removed from the SCS Capital Expenditure.

- There is currently a known limitation to the percentage of dedicated connection assets for domestic and rural and small commercial and industrial connection projects. The calculations were derived using prior year samples which represented five percent of all connection works for domestic and rural and small commercial and industrial connection projects. These included projects which were entirely Ergon Energy funded, and those which involved capital contributions. Ergon Energy recognises that the samples should be taken only from projects that were entirely funded by Ergon Energy, as these percentages are applied to Connection Capital Expenditure from the general ledger that are exclusive of capital contributions. Given data limitations this is currently not possible, however Ergon Energy will endeavour to improve the sampling process in future regulatory years to address this limitation.
- Consistent with the Actual 2018-19 SCS disposals, actual Network Services disposals are set equal to the actual 2018-19 SCS disposals and are split between the 2015-20 Capex RFM for Network Services and 2015-20 Legacy RFM for Network Services, depending on when the disposed assets were originally purchased. Disposed assets purchased prior to 1 July 2010 are included in the 2015-20 Legacy RFM for Network Services, and those purchased on or after 1 July 2010 are included in the 2015-20 Capex RFM for Network Services. Disposals in 2018-19 are split between the categories Additions and Disposals depending on the source Roll Forward Model being the Network Services Capex Model, or the Network Services Legacy Model respectively. Network Service additions are net of $3.83M ($nominal) disposals.
- Capital Contributions are not entered into the 2015-20 RFM Capex for Network Services or the 2015-20 RFM Legacy for Network Services, because Capital Contributions are removed from the SCS additions as described above.

Opening RAB Values

- The opening Network Services RAB as at 1 July 2010 in the 2010-15 Legacy RFM for Network Services is set equal to the closing RAB in the 2005-10 RFM for Network Services as calculated in cells L359:L388 of the Total Actual RAB Roll Forward tab.

- This approach outlined in the previous bullet point differs from AER's RFM, which requires that the opening RAB, rather than the closing RAB, of the final year of the previous regulatory control period be entered. The reason Ergon Energy has deviated from the AER's RFM is to remove the need for the RFM to adjust for the difference between forecast and actual net capex in 2009-10. No adjustment is necessary as the actual 2009-10 additions and disposals are now available to be rolled into the RAB.

- Consistent with the 2010-15 RFM Capex for SCS, the opening RAB in the 2010-15 RFM Capex for Network Services is set equal to zero.

- The opening Network Services RAB as at 1 July 2015 in the 2015-20 Legacy RFM for Network Services is set equal to the closing RAB in the 2010-15 Legacy RFM for Network Services as calculated in cells R359:R388 of the Total Actual RAB Roll Forward tab. These cells in the 2010-15 Legacy RFM for Network Services apply the same adjustments to the 30 June 2015 RAB as the AER to remove the value of those assets shared in the provision of ACS services (for those services reclassified in the 2015-20 Final Distribution Determination from SCS to ACS)

- As noted above, this approach outlined in the previous bullet point differs from AER's RFM. There is no need for the RFM to adjust for the difference between forecast and actual net capex in 2014-15 as the actual 2014-15 additions and disposals values are now available to be rolled into the RAB

- The opening Network Services RAB as at 1 July 2015 in the 2015-20 Capex RFM for Network Services is set equal to the closing RAB in the 2010-15 Capex RFM for Network Services as calculated in cells R359:R388 of the Total Actual RAB Roll Forward tab. These cells in the 2010-15 RFM Capex for Network Services apply the same adjustments to the 30 June 2015 RAB as the AER to remove the value of those assets shared in the provision of ACS services (for those services reclassified in the 2015-20 Final Distribution Determination from SCS to ACS)

Other Matters

Ergon Energy asset categories (as reported in the SCS and ACS RFMs and Annual Reporting RINs) have been directly mapped to the required economic benchmarking RAB asset categories, with the exception of some non-network asset categories (see below).

For some non-network asset categories (buildings, motor vehicles and plant and equipment), the AER definitions require Ergon Energy to split assets between short and long-life assets categories. Ergon Energy does not report data on this disaggregated basis. However, asset additions are readily determined from the asset register along with their lives. This information was used to apportion the relevant opening balances, additions and disposals to the required short and long-life categories

Ergon Energy has apportioned total buildings, motor vehicles and plant & equipment attributable to short and long life categories on the basis of asset addition for each asset. Asset additions are readily determined from the asset register along with the associated asset lives. With motor vehicles (as an example) heavy vehicles and a % of total vehicle additions was determined. This was then used to split total vehicle Capex between short and long lives. The same process was used for buildings and for plant & equipment. RAB disposals are allocated between short and long lived assets based on asset additions to these categories. The apportionment for Network Services is the same as that for SCS, and the apportionment of the ACS shared asset adjustment to the 2014-15 closing RAB values for buildings, motor vehicles and plant & equipment is also performed using the same method.

Network Services RAB roll-forward

Ergon Energy has adopted the AER's RFM to determine the Network Services RAB for 2018-19. However, consistent with the approach for SCS, forecast straight line depreciation for Network Services replaces the actual straight line depreciation for Network Services in 2018-19 onwards.

Network Services straight line depreciation is calculated using the AER's RFM. The Network Services opening RAB (which recognises 2014-15 actual capex and disposals), forecast Network Services capex and the SCS remaining lives are used in the Network Services depreciation calculation.

Of note, the 1 July 2015 Opening Asset Value included $8.09M in equity raising costs which is used to calculate the inflation addition and forecast depreciation amounts included in Table 3.3.1. In Table 3.3.2 the inflation addition and forecast deprecation amount for equity raising costs has been excluded as the nature of the cost doesn't meet with asset class definitions for reporting this table. A difference arises between the closing and opening values as a result.

The calculation of forecast Network Services net capex follows the same approach as that for 2018-19 actual net Network Services capex as outlined earlier in this Basis of Preparation document, with the difference being that forecast SCS net capex as per the 2015-20 Final Distribution Determination is used instead of actual net capex.

Consistent with the SCS and ACS RIN values described earlier in this document, 2010-11 to 2018-19 inclusive network services additions and disposals are calculated (using the approach outlined above) based on actual SCS capex and disposal values. The value of disposals reflects gross proceeds of sales basis for 2016-17 to 2018-19 (NBV for all years prior). The term disposal value is not defined in the NER, however the AER considered that using the sale or depreciated value as the disposal value was acceptable in the AER's RFM Final Decision for Electricity Distribution Network Service Providers (June 2008). Ergon Energy adopted the sale value in its Regulatory Proposal to the AER for the 2015-20 regulatory control period, accepted by the AER. This is a change to the prior regulatory control periods approach using depreciated value.

2010-11 to 2018-19 opening RAB, closing RAB, Inflation addition for network services are calculated based on the network services additions and disposal values in accordance with calculations within the RFM adopted by the AER in its Final Distribution Determination.

Total disaggregated RAB asset values – Capital contributions

For 2018-19 the Ergon Energy 2018-19 AER Annual Reporting RIN and general ledger separately reported/recorded the capital contribution revenue earned for SCS.

Asset Lives

- Asset lives – Ergon Energy has adopted the standard and remaining lives for SCS and ACS as approved by the AER in the 2015-20 Final Distribution Determination as at 1 July 2010 in the respective 2010-15 RFMs. Similarly, Ergon Energy has also adopted the standard and remaining lives for SCS and ACS as approved by the AER in the 2015-20 Final Distribution Determination as at 1 July 2015 in the respective 2015-20 RFMs.
- Asset lives – For Network Services, Ergon Energy has adopted the standard and remaining lives for SCS as approved by the AER in the 2015-20 Final Distribution Determination as at 1 July 2010 in the respective 2010-15 RFMs. Similarly, Ergon Energy has also adopted the standard and remaining lives for SCS as approved by the AER in the 2015-20 Final Distribution Determination as at 1 July 2015 in the respective 2015-20 Network Services RFMs

Asset Lives – Estimated Service Life of New Assets

A mapping exercise was applied to data obtained from the fixed asset register whereby data was grouped into the RAB Asset categories required by the AER, in accordance with category definitions provided in Chapter 9.

Where RAB Asset categories contained assets of differing lives, a weighted average estimated life was calculated based on replacement cost using the formulae prescribed by the AER (equation 1, weighted average asset life calculation).

Asset Lives – Estimated Residual Service Life

A mapping exercise was employed on data obtained from the fixed asset register whereby data was grouped into the RAB Asset categories required by the AER, in accordance with category definitions provided in Chapter 9.

Where RAB Asset categories contained assets of differing lives, a weighted average estimated life based on replacement cost was calculated using the formulae prescribed by the AER (equation 1, weighted average asset life calculation).

When assessing straight line depreciation for the RAB in Template 3.3 (Assets), the depreciation is based on remaining asset lives from the AER's 2015-20 Final Determination for Ergon Energy.

Ergon Energy submitted two separate RFMs (a "Legacy" RFM and a "Capex" RFM). The Legacy RFM relates to assets existing before 1 July 2010, while the Capex RFM relates to assets acquired over the 2010-15 regulatory control period. The closing RAB values as at 30 June 2015 from each RFM were then combined to give the opening RAB values as at 1 July 2015, as used in the PTRM for the 2015-20 regulatory control period. Rolling forward the 1 July 2010 RAB in the Legacy and Capex RFMs was done to more accurately calculate the weighted average remaining life as at 1 July 2015 and in turn produce a more accurate depreciation calculation for the purposes of calculating SCS revenues in the 2015-20 regulatory control period. This approach was approved by the AER in its 2015-16 Final Distribution Determination for Ergon Energy.

The residual service lives for the purposes of reporting Table 3.3.4 have been populated in accordance with Template requirements using lives from Ergon Energy's fixed asset register. The table does not reflect the more refined asset life segregation between pre 1 July 2010 and post 30 June 2010 purchases as approved by the AER. Therefore, caution should be taken when assessing depreciation expense in relation to remaining asset lives reported in Table 3.3.4.

6.5 Assumptions

No assumptions were made.

6.6 Estimated Information

Page 26 of the Instructions and Definitions document issued by the AER in November 2013 states:

“When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if Ergon Energy can provide Actual Information for the Variables in Table 4.2 [renamed table 3.3.2] it must do so; otherwise Ergon Energy must provide Estimated Information.”

Asset Value Roll Forward – SCS and ACS

Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) for 2018-19. That is, the 2018-19 opening and closing RAB values, additions, disposals, capital contributions, forecast straight line depreciation and inflation of the 2018-19 opening RAB values are reported as actuals. As such, Ergon Energy has not reported any estimated values for SCS or ACS in 2018-19.

Annual Value Roll Forward – Network Services

Ergon Energy has reported all values as actual information.

Total disaggregated RAB asset values – Capital contributions

Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term).

Asset Lives – Estimated Service Life of New Assets & Estimated Residual Service Life

Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in template 4, table 3.3.4 (Asset Lives).

6.7 Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

Refer to Basis of Preparation for Template 3. Opex, which will discuss any changes in accounting policies impacting capex or opex (if at all) for the regulatory year.

No accounting policies adopted by Ergon Energy have impacted on capital contributions received.

Asset lives reported are a non-financial data set, and accordingly changes in accounting policy do not impact it.

7 BOP - 3.4 Operational Data

7.1 Scope of BOP

7.1.1 Table 3.4.1 - ENERGY DELIVERY

7.1.2 Table 3.4.2 - CUSTOMER NUMBERS

7.1.3 Table 3.4.3 - SYSTEM DEMAND

7.2 Compliance with AR RIN Requirements

All entry fields are shaded yellow indicating mandatory data fields, and accordingly have been populated.

Table 3.4.1 - Energy Delivery

Energy Delivery

DOPED01 entry fields shaded yellow, indicating mandatory data fields have been populated.

Total Energy Delivered reported is the total metered or estimated energy delivered at the customer charging locations (rather than the import location from the TNSP).

Energy Grouping – Delivery by Chargeable Quantity

Entry field's shaded yellow, indicating mandatory data fields have been populated.

'*Energy Delivered where time of use is not a determinant'* (DOPED0201) relates only to energy delivered that was not charged for peak, shoulder or off-peak periods. This heading includes the Bands from Inclining Block tariffs.

Ergon Energy's Time of Use tariffs include Peak and Off-Peak only, and actual results are shown.

This is consistent with the AER's clarification received on 28 April 2015 which stated that where Ergon Energy does not charge for energy delivery on a peak, off peak or shoulder basis then zeros should be entered against these variables in table 3.4.1.1.

Energy Received from TNSP and Other DNSPs by time of Receipt

'*Energy Received from TNSP and other DNSPs not included in the above categories'* (DOPED0304) relates only to energy received that was unable to be allocated to peak, shoulder or off-peak periods.

In this regard, a wholesale time of use schedule does not exist as relevant to Energy Received. Accordingly, no disaggregation has been provided for time of use variables (DOPED0301-DOPED0303).

This is consistent with the AER's clarification received on 28 April 2015 which stated that if Ergon Energy is not billed for energy it receives on a peak, off peak or shoulder basis then zeros should also be entered against these variables in table 3.4.1.2.

Energy Received into DNSP system from Embedded Generation by Time of Receipt

'Energy Received from embedded generation not included in above categories from non-residential embedded generation (DOPED0404) relates only to energy received that was unable to be allocated to peak, shoulder or off-peak periods.

In this regard, a wholesale time of use schedule does not exist in relation to Energy Received. Accordingly, no disaggregation has been provided for time of use variables DOPED0401-DOPED0403.

Similarly, data for variables DOPED0405 – DOPED0407 in relation to energy received from Embedded Generation (residential) has not been recorded by Ergon Energy and accordingly, has been entered as '0'.

This is consistent with the AER's clarification received on 28 April 2015. In this clarification, the AER stated if Ergon Energy is not billed for energy it receives on a peak, off peak or shoulder basis then zeros should also be entered against these variables in table 3.4.1.3.

All other entry fields shaded yellow indicating mandatory data fields, have been populated.

Energy received from embedded generation not included in above categories from residential embedded generation (DOPED0408) has been populated.

Energy Grouping – Customer Type or Class

Ergon Energy confirms the category breakdown is consistent with the customer types reported in Table 3.4.2.1 Customer numbers, with the exception that Other Customer Class Energy Deliveries includes unmetered energy delivered (which in table 3.4.1.4 is separately reported for customer numbers).

Table 3.4.2 - Customer Numbers

Distribution Customer Numbers by Customer Type or Class

Ergon Energy confirms the category breakdown is consistent with the customer types reported in Table 3.4.1.4 Energy grouping - customer type or class (refer section above), with the exception that Unmetered customer numbers are reported separate to “Other Customer” class (in table 3.4.1.4 they are combined as ‘other).

‘Other Customer Numbers’ (DOPCN0106) was utilised only where customers were unable to be allocated to the other customer classes.

Distribution Customer Numbers by Network Location

All entry fields are shaded yellow indicating mandatory data fields, and accordingly have been populated, with the exception of ‘DOOPCN0201’ for CBD Network - Ergon Energy does not have any feeders classified as CBD.

Ergon Energy notes that DOPCN02 does NOT reconcile to DOPCN01 in Distribution Customer Numbers by Network Location, given DOCPN01 includes transmission or unknown (unclassified) feeder classes. No category was provided for these customers in DOPCN0201-DOPCN0204.

TABLE 3.4.3 - SYSTEM DEMAND

Annual System Maximum Demand (Zone Substation) (MW)

Variables DOPSD0102, DOPSD0103, DOPSD0105 and DOPSD0106 have been populated. All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Annual System Maximum Demand (Transmission Connection Point) (MW)

The orange cells associated with Variable Codes DOPSD0108, DOPSD0109 and DOPSD0111 and DOPSD0112 have been populated.

Annual System Maximum Demand (Zone Substation) (MVA)

The orange cells associated with Variable Codes DOPSD0202, DOPSD0203 and DOPSD0205 and DOPSD0206 have been populated.

Annual System Maximum Demand (Transmission Connection Point) (MVA)

The orange cells associated with variable DOPSD0208, DOPSD0209 and DOPSD0211 and DOPSD0212 have been populated.

Power Factor Conversions (Overall Network)

DOPSD0301 is shaded yellow indicating a mandatory data field, and has been populated.

Power Factor Conversions (Remaining Voltage Levels)

Where variables are not relevant to Ergon Energy, these have not been populated.

Demand Supplied (for Customers Charged on this Basis) (MW)

All entry fields are shaded yellow indicating mandatory data fields however it is noted in the RIN that population is only required where Ergon Energy charges customers for Maximum Demand supplied.

In instances where Ergon Energy cannot distinguish between contracted and measured Maximum Demand, demand supplied was allocated to contracted Maximum Demand. This includes a large amount of customers on the Threshold Demand tariff.

Ergon Energy commenced charging customers on a kVA (MVA) basis as of 1 July 2015. Customers are still being migrated from the MVA tariffs to these newer kVA tariffs as is evident in the numbers reported.

Demand Supplied (for Customers Charged on this Basis) (MVA)

All entry fields are shaded yellow indicating mandatory data fields however it is noted in RIN that population is only required where Ergon Energy charges customers for Maximum Demand supplied. This was also confirmed following AER review of Ergon Energy's initial submission of the previous Benchmarking RIN, in which Ergon Energy had calculated (using a conversion factor) data on an 'MVA measure' basis.

Ergon Energy commenced charging customers on a kVA (MVA) basis as of 1 July 2015. Where previous years information was not available in regard to MVA measures of Demand Supplied for contracted and Measured demand and "zeroes" were entered. This is consistent with the clarification received from the AER on 8 April 2014, which stated "zeros should be entered into table 3.4.3.7. The correct response to table 3.4.3.7 is to input the demand for which customers are charged. This should be based on the units of measurement upon which the customers were charged. If Ergon Energy only charges customers for demand based on MWs then 0s should be input into table 3.4.3.7."

7.3 Sources

TABLE 3.4.1 - ENERGY DELIVERY

Energy Delivery & Energy Grouping – Delivery by Chargeable Quantity

For year 2018-19, data has been sourced from Ergon Energy's billing system PEACE. Monthly billing reports , based on Statement of Charges monthly periods, are collated to provide actual data required.

Energy Received from TNSP and Other DNSPs by time of Receipt

Source is TNSP (PLQ) monthly billing files which are checked to metering data from Meter Data Agents (MDAs) and DNSP (Energex) monthly billing files. These billing files are checked to data from MDA.

Energy Received into DNSP system from Embedded Generation by Time of Receipt

Energy data for non-residential generators was sourced by Ergon Energy from National Electricity Market (NEM) settlements metering. All meters are interrogated by AEMO accredited MDAs and passed to Ergon Energy LNSP in accordance with Chapter 7 of the NER.

This data is automatically stored in the Ergon Energy DNSP central data repository - Network Optimisation Data Warehouse (NODW) for analysis by the various Ergon Energy Asset Development planning groups.

An aggregate load measurement point (LMP) was setup to cater for requirements, based on a new system. Only the energy received channel (B) is used in the aggregation. This aggregate LMP is up dated when new and replacement measured data has been received and updated when the tool is accessed. The aggregate definition is maintained, as is all Ergon Energy aggregate LMPs, in line with new installations of embedded generation impacting on the Ergon Energy network. Data for a very small number of Embedded Generators with low Generation Output (kW) is collected from NEM12 files and PEACE where required. This is impacted by the type of Meter and the type of data that each Meter captures

DOPED0408 (residential) data was sourced from the network billing system (PEACE), using a Network Tariff Code specific to residential Embedded Generation. Data is inclusive of all market customer premises supplied by Ergon Energy. (ISO areas not including Mt Isa were not included in these figures)

Energy Grouping – Customer Type or Class

For year 2018-19, data has been sourced from Ergon Energy’s billing system PEACE. Monthly billing reports based on Statement of Charges monthly periods, are collated to provide actual data required.

Note: these sources were adopted also for Template 3.1, table 2.2 Revenue Grouping by customer class or type

Table 3.4.2 - Customer Numbers

Distribution Customer Numbers by Customer Type or Class

Ergon Energy has sourced customer numbers data for the start of the period and for the end of the period from the Peace system. Counts are of unique National Metering Identifiers (NMIs) that are identified as having Ergon Energy as their DNSP.

Distribution Customer Numbers by Network Location

Ergon Energy has sourced customer numbers data from the Market Transaction system (Peace). Counts are of unique NMIs that are identified as having Ergon Energy as their LNSP.

Table 3.4.3 - System Demand

Annual System Maximum Demand

Data has been sourced from Substation Investment Forecasting Tool (SIFT).

The SIFT database is maintained for producing network demand forecasts of zone and bulk supply substations as well as Transmission Connection Points (TCPs). Access to the environment is secure and provided only to those persons who require access to conduct and manage the load forecasting process, and planning studies, with any changes to the datasets tracked and recorded.

The database is updated annually with substation demand data from the Network Operational Data Warehouse (NODW) previously the variables were stored in the Statistical Metering Database (SMDB). Network Element Time Series Metering Tool (NETS) accesses the NODW and stores load information on network assets.

Power Factor Conversions

Ergon Energy extracted power factor data from kW and kVA information stored in the Ergon Energy DNSP central data repository (NODW), which extracts this information from metering units across a significant proportion of Zone Substations over half hourly intervals.

Demand Supplied (for Customers Charged on this Basis) (MW & MVA)

Ergon Energy has sourced data from the Network Billing system (PEACE).

7.4 Methodology

Table 3.4.1 Energy Delivery

Energy Delivery & Energy Grouping – Delivery by Chargeable Quantity

Ergon Energy employed a methodology whereby kWhs for energy delivery were summated from monthly billing data files into annual totals. As the source file captured data in kWhs the results were converted to GWhs.

Energy Received from TNSP and Other DNSPs by time of Receipt

Energy delivered to the Mount Isa distribution network (which includes Cloncurry but not the 220kV connected Carpentaria Mineral Province mines) is included in this aggregation given derogations which include this as part of the AER-regulated Ergon Energy regulated network. There is no TNI in any Australian Energy Market Operator (AEMO) documentation servicing this area of the network.

Energy Received into DNSP system from Embedded Generation by Time of Receipt

Energy received in to the network from larger installations of embedded generation is recorded on a half hour basis.

DOPED0408 (residential) data represents the sum of all KWh recorded with a Network Tariff Code specific to Embedded Generation with a Residential Customer Classification Code, from the PEACE data source.

Energy Grouping – Customer Type or Class

The disaggregation for all variables is based on actual data. High/low classification is now based on DLF code,

Table 3.4.2 - Customer Numbers

Distribution Customer Numbers by Customer Type or Class

Distribution Customers represent the average number of active NMIs in the network the relevant regulatory, calculated as the average number of NMIs on the first day of the regulatory year and on the last day of the regulatory year. Of note:

- Each NMI has been counted as a separate customer;
- Both energized and de-energised NMIs are counted; and
- Extinct and Greenfield site NMIs are excluded.

Residential data is identified by the NMI Customer Classification Code (CCC). Voltage & Demand splits were identified by the Network Tariff Types, whilst the Unmetered premises were identified by the NMI numbering range.

For Unmetered customers, excludes public lighting connections (also identified by the NMI numbering range). Unmetered energy usage for billing purposes is calculated using an assumed load profile.

Ergon Energy is still recording a sizeable increase in the unmetered customers as the National Broadband Network rollout continues to add a large amount of Unmetered Supplies to our network also.

Distribution Customer Numbers by Network Location

Distribution Customers represents the average number of active NMIs in the network, calculated as the average number of NMIs on the first day of the regulatory year and on the last day of the regulatory year. Of note:

- Each NMI has been counted as a separate customer;
- Both energized and de-energised NMIs are counted; and
- Extinct and Greenfield site NMIS are excluded.

In order to disaggregate data by feeder types (Urban, Short Rural and Long Rural), a NMI was identified as being attached to a feeder which in turn enabled the identification of the required feeder classes.

TABLE 3.4.3 - SYSTEM DEMAND

Annual System Maximum Demand (Zone Substation) (MW)

In order to obtain Weather-adjusted variables, Ergon Energy has employed the following methodology:

- Constructed a multivariate maximum demand equation for each season of Summer or Winter. Variables in the equation include maximum temperature, minimum temperature and variables for Saturday, Sunday and public holidays.
- Daily historical BOM temperatures are passed through each equation and maximum annual demand is obtained. The listing of annual peak demand is made for all set of consistent temperature records from each associated weather station.
- 50 POE and 10 POE measured from histogram of annual peak demands.

Annual System Maximum Demand (Transmission Connection Point) (MW)

In order to obtain Weather adjusted variables, Ergon Energy has employed a methodology involving:

- Constructed a multivariate maximum demand equation for each season of Summer or Winter. Variables in the equation include maximum temperature, minimum temperature and variables for Saturday, Sunday and public holidays.

- Daily historical BOM temperatures are passed through each equation and maximum annual demand is obtained. The listing of annual peak demand is made for all set of consistent temperature records from each associated weather station.

- Weather station selected by referral to associated Zone Substation weather station. Where a transmission connection point has multiple Zone Substations attached, the most common weather station is selected for the transmission connection point weather correction.

- 50 POE and 10 POE measured from histogram of annual peak demands.

Annual System Maximum Demand (Zone Substation & Transmission Connection Point) (MVA)

Weather adjustment MVA data have been obtained by multiplying raw MVA by the ratio of (MW temperature adjusted value to raw MW value) for the same regulatory year.

Power Factor Conversions (Overall Network)

DOPSD0301 '*average overall power factor conversion*' is required to represent the total MW divided by the total MVA.

The overall network power factor was derived from a coincident summation of kW and kVAr at all the transmission network connections points (native) in the Ergon Energy network, with the peak demand power factor calculated from this data set at the time of the native system maximum demand.

Power Factor Conversions (Remaining Voltage Levels)

The data was extracted from NODW, categorised according to Table 3.4.3.5, and calculated to obtain totals. Basic data cleansing was performed by eliminating all feeders with peak power factors less than 0.4 and greater than 0.999 after extraction from NODW.

Some volatility exists in the metering sources for both the 6.6kV and 220kV power factor calculation, hence significant change in power factor from 2018-19. However, because of the very small amount of network supplied at both 6.6kV and 220kV, it is considered that such volatility is within normal tolerances. Manual extracts from the NODW were taken for categories with limited number of assets including the 3.3kV rating class.

FME (Feature Manipulation Engine - www.safe.com) has been used to obtain the data for DOPSD302-DOPSD0314 from the standard specified resources and complete calculations in an identical method to previous years using a C++ coded program that extracted and compiled the data list (this program is no longer in use). FME is data translation software that connects to the required data sources and completes required analysis in a method able to be replicated in a consistent manner.

Demand Supplied (for Customers Charged on this Basis) (MW & MVA)

Network Use of System (NUOS) charges classed as Network DUOS Capacity Charge (NDCC) were used to identify the Contracted demand proportions for Individually Calculated Customer (ICC), Connection Asset Customer (CAC) and Embedded Generator (EG) type connections.

NUOS charges classed as Network DUOS Actual Demand Charge (NDADC) were used to identify the Measured demand proportions for ICC, CAC and EG type connections.

All Standard Asset Customer (SAC) - Large connections are noted to only have either an Actual Demand charge or a Threshold Demand charge and therefore were reported under the Contracted Demand split. In the case of the Threshold Demand we have used the actual read maximum demand as we have deemed that the demand below the applicable threshold is charged at a zero amount and as such should still be counted as charged.

ICC, CAC and EG type connections are charged (and hence accounted for) on a monthly basis. For 2018-19 onwards the maximum monthly usage per customer is summated to provide the relevant figure, whereas previously, summated values were the summation of the monthly chargeable quantities.

7.5 Assumptions

No assumptions were made.

7.6 Estimated Information

Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term)

7.7 Explanatory Notes

Changes in Accounting Policies (Financial information - Actual or Estimated):

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy

8 BOP - 3.5 Physical Assets

8.1 Scope of BOP

8.1.1 Table 3.5.1 - NETWORK CAPACITIES

8.2 Compliance with AR RIN Requirements

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres)

Circuit lengths has been calculated from the line length (measured in kilometres) of lines that are in service and regulated (total length of feeders including all spurs), where each single wire earth return (SWER) line, single phase line, and three phase line count as one line. A double circuit line has been counted as two lines. Circuit lengths do not take into account vertical components such as sag and end lengths.

8.3 Sources

The data for 3.5.1.1 and 3.5.1.2 (overhead and underground network length) comes from the Ergon Energy Smallworld replicated spatial database. This database is replicated from the Smallworld geographic information (GIS) electrical data store.

8.4 Methodology

Scripts were run against the snapshot of Smallworld data taken on the 1st of July to extract the number and length of conductors broken down by voltage and type. Conductors that did not align with any of the prescribed categories were placed in the other groupings. Conductors with voltages of 12.7kV and 19.1kV were placed in the SWER category.

Services lines are not separately identified within the Ergon Energy's systems but are represented as standard LV overhead line. Service lines were identified, calculated and removed from the LV line total lengths. Service lines were found by finding LV with a connection point at one end and a length of less than 50m. Where an LV line is greater than 50m the length of the LV line was reduced by 50m and added to the service line totals.

8.5 Assumptions

It is assumed that the maximum length of a service line is 50m.

8.6 Estimated Information

Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in this Template.

8.7 Explanatory Notes

Not applicable.

9 BOP 3.5.1 - Network Capacities

9.1 Scope of BOP

9.1.1 Table 3.5.2 - TRANSFORMER CAPACITIES

9.2 Compliance with AR RIN Requirements

Circuit capacity (MVA): Overhead low voltage distribution

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Where two sets of lines run on different sets of poles (or towers) but share the same easement these are counted as separate routes for the variable DOEF0301.

Ergon Energy notes that the AER has changed the variable numbers associated with this table in its revised templates for 2013-14 to 2018-19. Therefore, care should be taken when reviewing variable data against submissions prior to 2013-14.

Consistent with the clarification received from the AER, Ergon Energy has reported against those asset categories previously reported against and have left blank any categories that are not relevant to its business. [DPA0303, DPA0308, DPA0312].

Distribution transformer capacity owned by High Voltage Customers

Where the transformer capacity owned by the customers connected at high voltage (DPA0502) was not available, Ergon Energy reported the summation of individual Maximum Demands of high voltage customers whenever they occur (i.e. the summation of single annual Maximum Demand for each customer) as a proxy for delivery capacity within the high voltage customers. This is consistent with the Instructions and Definition document issued by the AER in November 2013, which states

"When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if Ergon Energy can provide Actual Information for Distribution Transformer capacity owned by High Voltage Customers it must do so; otherwise Ergon Energy must provide Estimated Information."

9.3 Sources

9.4 Methodology

Circuit capacity (MVA): Overhead low voltage distribution

Ergon Energy has provided ‘Estimated Information’ (as per the AER’s defined term) in relation to variable [DPA0301] Overhead low voltage distribution lines contained in Template 3.5, Table 3.5.1.3.

When sourcing data in relation to overhead low voltage distribution line was discovered that that 57.6% of LV lines were not included in the assessment of the weighted average MVA capacity, as these have unknown characteristics. Further, it was noted that these lines are most probably older LV lines (e.g. Imported from legacy systems at the time of SmallWorld implementation) that is likely to have smaller capacities thus potentially over reporting this data.

Discussions with the auditors, we came to a conservative assumption to use a small copper conductor (0.080”) as the construction of the 57.6% LV lines that were not included.

On this basis Ergon Energy considers that the best estimate has been provided.

Distribution transformer capacity owned by High Voltage Customers

Estimated Information has been presented in accordance with the Instruction at Table 3.5.2 Transformer Capacities Variables. This is consistent with the Instructions and Definition document issued by the AER in November 2013, which states

“When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if Ergon Energy can provide Actual Information for Distribution Transformer capacity owned by High Voltage Customers it must do so; otherwise Ergon Energy must provide Estimated Information.”

9.5 Assumptions

No assumptions were made.

9.6 Estimated Information

Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined term) in relation to all variables contained in this Template.

9.7 Explanatory Notes

Not applicable.

10 BOP 3.5.1 - Network Capacities

10.1 Scope of BOP

10.1.1 Table 3.5.2 - TRANSFORMER CAPACITIES

10.1.2 Table 3.5.3 - PUBLIC LIGHTING

10.2 Compliance with AR RIN Requirements

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Where two sets of lines run on different sets of poles (or towers) but share the same easement these are counted as separate routes for the variable DOEF0301.

Consistent with the clarification received from the AER, Ergon Energy has reported against those asset categories previously reported against and have left blank any categories that are not relevant to its business. [DPA0303, DPA0308, DPA0312].

Consistent with the clarification received from the AER, Ergon Energy has reported against those asset categories previously reported against and have left blank any categories that are not relevant to its business. [DPA0402, DPA0404, DPA0407].

Table 3.5.2 - Transformer Capacities Variables

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Distribution Transformer Total Installed Capacity

Distribution transformer capacity owned by Ergon Energy (DPA0501) - the reported data is the nameplate continuous rating including forced cooling.

DPA0503 Cold Spare Capacity represents the total capacity of spare transformers owned by Ergon Energy but not currently in use. Cold Spare Capacity is included in Distribution transformer capacity owned by Ergon Energy (DPA0501).

Cold Spare Capacity (Distribution Transformer and Zone Substation)

Cold Spare Capacity represents the total capacity of spare transformers owned by Ergon Energy but not currently in use. Cold Spare capacity is included in the total Distribution transformer capacity owned by Ergon Energy (DPA0501), and total zone substation transformer capacity (DPA0604).

Zone Substation Transformer Capacity

Measures are the summation of normal assigned continuous capacity/rating (with forced cooling or other capacity improving factors included). They include both energised transformers and cold spare capacity.

The assigned rating must be (if available) the rating determined from results of temperature rise calculations from testing, else the nameplate rating is reported.

For zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders is reported instead of transformer capacity.

Cold Spare Capacity represents the total capacity of spare transformers owned by Ergon Energy but not currently in use. Cold spare capacity is included in the total zone substation transformer capacity (DPA0604). It is noted that year's submission of Cold Spare Capacity includes the addition spare substation transformer capacity (i.e. standby transformers), in accordance with the AER's definition of "Cold Spare Capacity".

Table 3.5.3 Public Lighting

The AER requires Ergon Energy to report the number of public lighting luminaires and public lighting poles in its network. For both variables, Ergon Energy is required to report numbers that include both assets owned by Ergon Energy and assets operated and maintained, but not owned by Ergon Energy. Only poles that are used exclusively for public lighting are to be included.

In addressing the minimum Basis of Preparation requirements, Ergon Energy makes the following comments in relation to variables for Public Lighting in Table 7-1.

Table 7-1 Consistency with Notice Requirements

Variable	**Consistency with Notice requirements**	**Addressing basis of preparation requirements**
DPA0701 to DPA0703	Public Lighting	All entry fields which are shaded yellow indicating mandatory data fields have been populated for the 2018-19 regulatory year. Only lamps and poles that are used exclusively for public lighting and are owned or gifted and operated by Ergon Energy are to be included. Consistent with clarification received from the AER following reissuance of templates for the 2018-19 regulatory year, Ergon Energy has reported against those asset categories previously reported against and have left blank any categories that are not relevant to its

		Business. [DPA0703].

10.3 Sources

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

Ergon Energy has sourced data from, and referred to the following standards or guidelines, in order to complete variables for Estimated Overhead Network Weighted Average Capacity, by Voltage Class (MVA):

- SOREP Oracle Spatial database (replicated SmallWorld GIS electrical datastore);
- Australian Standards;
- IEC Standards;
- ESAA D(b)5; and
- Ergon Energy Plant Rating Guidelines.
- Olex cable manufacturer catalogue calculations.

Table 3.5.2 - Transformer Capacities

Distribution Transformer Total Installed Capacity

The source data for Distribution transformer capacity owned by High Voltage was obtained from the DCOS and PEACE billing reports

The total capacity of installed distribution transformers was sourced from a Current State Assessment database which each year stores the amount of distribution transformer capacity connected to each distribution feeder. The installed distribution transformer capacity is stored in Ergon Energy's corporate database.

Cold Spare Capacity (Distribution Transformer and Zone Substation)

Relevant to DPA0503 and DPA0605, Cold Spare capacity data was sourced from the Ellipse Production table files using a Mincom Ellipse Reporting (MERS). A snap shot report has been designed to run on early the first day of each month. The report used for the data in this regulatory period was taken on the July 2019. Furthermore spare transformer capacity (i.e. standby transformers) was sourced from SIFT substation records for the relevant financial year.

Zone Substation Transformer Capacity

2018-19 totals are based on current corporate data extracted from Ellipse as a snapshot of the system at the end of the 2018-19 regulatory year.

Table 3.5.3 Public Lighting

Public Lighting data has been sourced from the PLUMS database and Smallworld GIS.

10.4 Methodology

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

Data in relation to Table 3.5.1.1 'Overhead network length of circuit at each voltage' was used. A methodology was employed whereby for lines interacting with more than one climate zones, the lowest rating was applied. Summer ratings were calculated.

Voltage drop and thermal limits of circuit components other than overhead lines and cables have not been considered when establishing the capacities of lines.

Data in relation to Table 3.5.1.2 'Underground circuit length each voltage' was used. Of note, the following assumptions were applied.

- Cables with similar characteristics given the same rating;
- Cables ambient air temperature calculated from spatial analysis with Ergon Energy Climate Zones;
- Cables ground temperature calculated from spatial analysis with 9 BOM Weather stations (nearest);
- Unknown Voltage & Phase attributes calculated from cable characteristics;
- Cables ratings assumed 2 adjacent cables, 900mm depth, Cyclic Rating Factor =1, Solid Bonded & TR=2.0;
- Summer & Winter Ratings were calculated.

Voltage drop and thermal limits of circuit components other than overhead lines and cables have not been considered when establishing the capacities of cables.

TABLE 3.5.2 - TRANSFORMER CAPACITIES

Distribution Transformer Total Installed Capacity

For Distribution transformer capacity owned by, ICC & CAC customers were taken from the annual DCOS file after removing those metered at low voltage (415 line etc.). Following, the maximum of actual charged maximum demand for each year or authorised demand was taken for each connection point. (Note: a connection point must have capacity of at least the authorised demand). The DCOS totals were then added to the of SAC High Voltage connections.

DCOS numbers were used for SAC High Voltage as no reliable, consistent, like for like, data for SAC High voltage connections is available over the required period. However, given that SAC High Voltage is less than 2% of totals, this was considered an acceptable estimation.

The data is obtained from monthly billing files received from Service Transaction Centre using Netbill, and other files produced for Pricing purposes.

ICC and CAC maximum demand is available in KVA ;a conversion factor was used to convert SAC High Voltage Demand to KVA. The distribution transformer cold capacity was added to the installed capacity values.

FME (Feature Manipulation Engine - www.safe.com) has been used to obtain the data for DPA0501 from the standard specified resources and compare to data in an identical method as previously mentioned above. FME is data translation software that connects to the required data sources and completes required analysis in a method able to be replicated in a consistent manner.

Cold Spare Capacity (Distribution Transformer and Zone Substation)

To obtain the Cold Spare Capacity values required for this report the Stock On Hand (SOH) value for each identified stock code was required early on the first day of the new regulatory period. This data was obtained from a snapshot report that was run on at the end of the 2018-19 financial year.

To calculate the Cold Spare Capacity value in MVA stock on hand value for the regulatory year was multiplied by the Capacity of the item which could be obtained from the Stock Code’s description.

The value for 'Cold Spare Capacity for distribution transformers - total installed capacity' (DPA0503) includes a Cold Spare Capacity component value of 17.091 MVA for Refurbished Distribution Transformers as well as owned stock, leading to a total value of 279.414 MVA.

With regards to Zone Substation's transformers Cold Spare Capacities (i.e. DPA0605) a slight change to methodology was applied for this year's submission to abide by the AER's definition of 'Cold Spare Capacity'. As done for previous years, inventory stock was taken evaluating 2018-19 Cold Spare Capacity stored as 831.65MVA (supplied by inventory systems which include Ellipse's inventory register). However added to this figure was the addition of addition of spare transformer capacity from zone substations (i.e. standby transformers) which are not energised during normal operation. The spare transformer capacity was sourced from SIFT records and evaluated to be 80.62 MVA for the 2018-19 financial year. Hence, DPA0605 = 831.65 + 80.62 = 912.270 MVA

Zone Substation Transformer Capacity

Transformer asset data was extracted from the corporate database, categorised according to Table 3.5.2.2, and summated to obtain totals.

FME (Feature Manipulation Engine - www.safe.com) has been used to obtain the data for DPA0601-DPA0603 from the standard specified resources and compare data in an identical method to previous years. FME is data translation software that connects to the required data sources and completes required analysis in a method able to be replicated in a consistent manner. These values are added to DPA0605 to produce DPA0604 - Total zone substation transfomer capacity (i.e. DPA0604 = DPA0601 + DPA0602 + DPA0603 + DPA0605).

Table 3.5.3 Public Lighting

For Public Lighting Luminaries a methodology was employed whereby Pivot tables were developed from PLUMS database to identify Public Lighting assets that were established in the database at the end of each regulatory year (financial year). Only Ergon Owned and Operated and Gifted and Ergon Operated lights have been included (previously known as Rate 1 & 2).

For Public Lighting Poles a methodology was employed whereby a query was run through Smallworld to identify Public Lighting assets that did not have Network Wires attached and as such were Street Light Only Poles. Customer Owned and Operated poles were excluded (previously known as Rate 3).

The Public Lighting luminaires and poles figure has slightly decreased from last year due to reclassification of lighting in isolated communities as Customer Owned and Operated and continued data matching between systems.

It is assumed that the Smallworld data is an accurate record of actual assets.

10.5 Assumptions

No assumptions were made.

10.6 Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this Template.

10.7 Explanatory Notes

The information in this template is a non-financial data set (both estimated and actual data), and accordingly is not impacted by any changes in accounting policy

For Table "3.5.1.3 - Estimated overhead network weighted average MVA capacity by voltage class", it is noted that the result for "DPA0302 Overhead 6.6 kV Capacity" has dramatically changed when compared to the previous year. This is due to the Design team recently re-rating the small population consisting of two 6.6kV OH feeders (sourced by Kidston substation) from 60 to 80

Degrees Celsius. This change has been translated into Smallworld Electronic Office in the last year resulting in dramatic changes in determining the average capacity (MVA) for this asset category.

11 BOP - 3.6 Quality of Service

11.1 Scope of BOP

11.1.1 Table 3.6.1 - RELIABILITY

11.1.2 Table 3.6.3 - SYSTEM LOSSES

11.1.3 Table 3.6.4 - CAPACITY UTILISATION

11.2 Compliance with AR RIN Requirements

Ergon Energy has prepared the information provided in Template 3.6.1 Reliability, 3.6.2 System Losses and 3.6.3 Capacity Utilisation Network Feeders reported in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN and with Economic Benchmarking RIN instructions and definitions (November 2013).

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

System losses are calculated in accordance with Equation 2 in the Instructions and Definitions at Appendix B to the RIN.

Capacity Utilisation

For this measure, capacities used are the summation of normal assigned continuous capacity/rating (with forced cooling or other capacity improving factors included).

The assigned rating must be (if available) the rating determined from results of temperature rise calculations from testing, else the nameplate rating is reported.

For zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders is used instead of transformer capacity.

11.3 Sources

Table 3.6.1 - Reliability

Ergon Energy has sourced data from its internal outage management and asset management systems.

Table 3.6.3 - System Losses

Ergon Energy has sourced data from its corporate sources, as detailed in the BOPs for Template 3.4 Operational data – see Energy Received and Energy Delivery for more details.

Table 3.6.4 -Capacity Utilisation

Ergon Energy has sourced data to report capacity utilisation from the same sources as those reported for DOPSD0201 non-coincident summated raw system annual maximum demand at the zone substation level (EB RIN Template 3.4) and DPA0604 Total zone substation transformer capacity (EB RIN Template 3.5).

11.4 Methodology

Table 3.6.1 Reliability

For the regulatory (financial) year 2018-19, Major Event Day Threshold (tMed 7.42) was calculated utilising 5 years of Daily SAIDI data using the required STPIS methodology.

Table 3.6.1 DQS0101 to DQS0108: As relevant, Ergon Energy has applied definitions and methodology as set out in the AER's Electricity DNSPs, STPIS (November 2009), which remains applicable for the current regulatory control period. The following comments are made across all variables.

- Ergon Energy notes that Average number of customers (the number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period and the number of customers at the end of the reporting period) was used as the denominator for the calculation as per the formula outlined in Appendix A of the AER's STPIS scheme.
- Only completed unplanned sustained (> 1min) interruptions are included.
- In the absence of specification, Whole of Network statistics were assumed to encompass the Summation of Urban, Short Rural & Long Rural (Customer Minutes, Customer Interruptions and Customer Numbers).
- An event caused by a customer’s electrical installation or failure of that electrical installation which only affects supply to that customer is not deemed an interruption as defined, “A sustained interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network” STPIS 2009 and CA RIN Appendix E 18.2]. These events have been confirmed through site inspection to have resulted from faults and failures within the customer’s installation and as such are considered to be an event beyond the boundary of the electricity supply network and therefore excluded from Ergon Energy reported reliability performance under the STPIS

Inclusive of MEDs

The following comments are made in relation to specific Reliability variables, provided in Template 3.6 Table 3.6.1 (Reliability performance **inclusive** of MEDs).

DQS0101 - Whole of network unplanned SAIDI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIDI calculation - Customer minutes divided by average number of customers
- Inclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme.

DQS0102 - Whole of network unplanned SAIDI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIDI calculation - Customer minutes divided by average number of customers
- Inclusive of the exclusions in clause 3.3(b) and exclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network.

DQS0103 - Whole of network unplanned SAIFI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIFI calculation - Customers interrupted divided by average number of customers
- Inclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme.

DQS0104 - Whole of network unplanned SAIFI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIFI calculation - Customers Interrupted divided by average number of customers
- Inclusive of the exclusions in clause 3.3(b) and exclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network.

Exclusive of MEDs

The following comments are made in relation to specific Reliability variables, provided in Template 3.6 Table 3.6.1 (Reliability performance **exclusive** of MEDs).

DQS0105 - Whole of network unplanned SAIDI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIDI calculation - Customer minutes divided by average number of customers
- Exclusive of the exclusions in clause 3.3(b) and Inclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme.

DQS0106 - Whole of network unplanned SAIDI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIDI calculation - Customers minutes divided by average number of customers
- Exclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network

DQS0107 - Whole of network unplanned SAIFI

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIFI calculation - Customers Interrupted divided by average number of customers
- Exclusive of the exclusions in clause 3.3(b) and Inclusive of exclusions in clauses 3.3(a) in accordance of the AER's STPIS scheme.

DQS0108 - Whole of network unplanned SAIFI excluding excluded outages

- Relevant Financial Year (Between 1 July and 30 June)
- Completed unplanned sustained (> 1 min) interruptions
- Feeder Classification: Whole of network (summation of UR, SR & LR)
- SAIFI calculation - Customers Interrupted divided by average number of customers
- Exclusive of the exclusions in accordance with clauses 3.3(a) & (b) of the AER's STPIS scheme and exclusive customer installation faults/failures which reside beyond the electricity supply network.

Table 3.6.3 - System Losses

All data provided in relation to System Losses is Actual information which is calculated using the following formula:

[Energy Received – Energy Delivery] *divide* Energy Received.

Table 3.6.4 -Capacity Utilisation

This data (DQS04) was determined by dividing the Non–coincident Summated Raw System Annual Maximum Demand provided as per DOPSD0201 by the Total zone substation transformer capacity as per DPA0604 whilst disregarding the Cold Spare Capacity component (DPA0605). Hence, DQS04 can be calculated in either two ways, namely:

DQS04 = DOPSD0201 / (DPA0601 + DPA0602 + DPA0603)

or alternatively,

DQS04 = DOPSD0201 / (DPA0604 - DPA0605)

{where DPA0604 = DPA0601 + DPA0602 + DPA0603 + DPA0605}

11.5 Assumptions

No assumptions were made.

11.6 Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all Reliability statistics.

Data represents Actual performance only in relation to unplanned interruptions, as defined in the AER's STPIS scheme for Electricity DNSPs (November 2009).

11.7 Explanatory Notes

The information in this template is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

Table 3.6.2 - ENERGY NOT SUPPLIED

11.8 Compliance with AR RIN Requirements

Ergon Energy has prepared the information provided in Template 3.6.2 Energy Not Supplied in accordance with the RIN requirements, including the Principles and Requirements set out in Appendix A and definitions in Appendix F to the RIN and with Economic Benchmarking RIN instructions and definitions (November 2013).

All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Chapter 7 Table 7.2 approach 3 *"average consumption of customers on the feeder based on their billing history"* as defined in the Economic Benchmarking RIN instructions and definitions (November 2013) has been applied to estimate the energy not supplied.

11.9 Sources

Ergon Energy has sourced data from its internal outage management and asset management systems for the relevant regulatory year.

Consumption for the "Energy Not Supplied" was sourced from the Network billing system Peace.

11.10 Methodology

Refer to Table 3.6.2: As relevant, Ergon Energy has applied definitions and methodology as set out in the AER's Electricity DNSPs, STPIS (November 2009) and Economic Benchmarking RIN instructions and definitions (November 2013), which remains applicable for the current regulatory control period. The following comments are made across all variables.

- The Average number of customers (the number of distribution customers is calculated as the average of the number of customers at the beginning of the reporting period and the number of customers at the end of the reporting period) was used as the denominator for the calculation as per the formula outlined in Appendix A of the AER's STPIS scheme.
- Only completed unplanned sustained (> 1min) interruptions are included.
- In the absence of specification, Whole of Network statistics were assumed to encompass the Summation of Urban, Short Rural & Long Rural (Customer Minutes, Customer Interruptions and Customer Numbers).
- An event caused by a customer's electrical installation or failure of that electrical installation which only affects supply to that customer is not deemed an interruption as defined, "A sustained interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network" STPIS 2009 and CA RIN Appendix E 18.2]. These

events have been confirmed through site inspection to have resulted from faults and failures within the customer's installation and as such are considered to be an event beyond the boundary of the electricity supply network and therefore excluded from Ergon Energy reported reliability performance under the STPIS

All export and import meter data from Peace for the regulatory reporting year for each NMI was extracted and loaded into a table. The standing data from PEACE for each NMI linking to the relevant Feeder was placed in this table. A query was then run to consolidate all NMIs' consumption data relating to each feeder to give their annual consumption. This total is then used to calculate the average customer consumption per minute per feeder.

Ergon Energy has estimated the Energy Not Supplied using data reported for unplanned/planned customer minutes off supply (Mins) multiplied by the average consumption by feeder (in minutes) sourced from Peace. This is in accordance with methodology Chapter 7, Table 7.2 approach three *"average consumption of customers on the feeder based on their billing history"* as defined in the Economic Benchmarking RIN instructions and definitions (November 2013) for energy not supplied, inclusive of the exclusions under clause 3.3(b) (Major Event Days) and exclusive of the exclusions in accordance with clauses 3.3(a) of the AER's STPIS scheme and exclusive of Customer Installation Faults/Failures which reside beyond the electricity supply network.

The calculations are based on current connectivity by feeder and not connectivity at the time of the outage. For some feeders that no longer active or have changed connectivity in the system ECORP the average consumption per minute over all feeders is used. The methodology adopted is irrespective of the time of day the outages occurred.

This calculation was performed for both Planned and Unplanned interruptions, with Total Energy Not supplied being the sum of DQS0201 and DQS0202.

11.11 Assumptions

Refer to 7.12 Estimated Information.

11.12 Estimated Information

By definition, Ergon Energy has provided 'Estimated Information' in relation to all variables contained in Template 3.6 Table 3.6.2.

Historical feeder connectivity is not captured by Ergon Energy, and therefore current connectivity is assumed. Consumption is identified for all feeders and was multiplied by the customer minutes. Where there is no current connectivity an average consumption across all feeders was used.

This is consistent with the Instructions and Definition document issued by the AER in November 2013, which states

"When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if Ergon Energy can provide Actual Information for energy not supplied it must do so; otherwise Ergon Energy must provide Estimated Information."

11.13 Explanatory Notes

Energy Not Supplied is a non-financial data set, and accordingly is not impacted by any changes in accounting policy.

12 BOP - 3.7 Operating Environment

12.1 Scope of BOP

12.1.1 Table 3.7.1 - Density Factors

12.1.2 Table 3.7.2 - Terrain Factors

12.1.3 Table 3.7.3 - Service Area Factors

12.2 Compliance with AR RIN Requirements

TABLE 3.7.1 - DENSITY FACTORS

All mandatory data entry fields have been populated.

TABLE 3.7.2 - TERRAIN FACTORS

DOEF0201 (rural proportion) and DOEF0205 (total spans) are shaded yellow indicating they are mandatory data fields, and accordingly have been populated.

Vegetation maintenance span cycles variables (DOEF0206-DOEF0207) have been provided as Actual Information.

TABLE 3.7.3 - SERVICE AREA FACTORS

All mandatory data entry fields, shaded yellow, have been populated.

Route Line length of lines is based on the distance between line segments. It does not include vertical components such as line sag.

The route Line Length does not equate to the circuit length as the circuit length includes multiple circuits. The circuit length is reported excluding the circuit length of service lines.

Following AER clarifications provided in relation to variable DOEF0301 which noted the intent of this variable is to measure the aggregate distance between poles and/or towers, Ergon Energy confirms that where:

- two sets of lines that run on different sets of poles (or towers) share the same easement the lines are counted separately;
- there are multiple circuits on a span, the length of each span is considered only once; and
- a span shares multiple voltages, the length of the span is also considered only once; and

captures the length of both underground cables and overhead lines

12.3 Sources

TABLE 3.7.1 DENSITY FACTORS

The source data for each numerator/denominator input is noted below in the section on methodology.

3.7.2 TERRAIN FACTORS

The source data for each variable is contained below in the section on methodology

TABLE 3.7.3 - SERVICE AREA FACTORS

Ergon Energy has sourced data from its SOREP Oracle Spatial database. This database is replicated from the Smallworld GIS electrical data store.

12.4 Methodology

TABLE 3.7.1 - DENSITY FACTORS

Values were obtained by using the following calculation as required in Instructions and Definitions for variables:

- "DOEF0101 – Customer density" was calculated by dividing the total number of customers (DOPCN01 from RIN Table 3.4.2.1) divided by the route Line Length (DOEF0301 from RIN Table 3.7). No conversions are required.

- "DOEF0102 – Energy density" was calculated by dividing the total energy delivered to customers (**DOPED01**) by the total number of customers (**DOPCN01**) from RIN Table **3.4.2.** The energy delivered was multiplied by 1000 to convert the figures to MWh.

- "DOEF0103 – Demand density" was calculated by dividing the total non-coincident system annual maximum demand (DOPSD0201 from RIN Table 3.4.3.3) by the total number of customers (DOPCN01 from RIN Table 3.4.2.1) from RIN Table 3.4.2. The total non-coincident system annual maximum demand was multiplied by 1000 to convert the figures to kVA.

Further information on the methodology employed to determine each numerator or denominator input is available in Table 4: Routine Line Length, as well as in the relevant sections of the BOP for EB RIN Template 3.4 Operational data for DOPCN01, DOPED01, DOPSD0201.

Table 9-1 Terrain Factors (RIN Table 3.7.2)

	Addressing Basis of Preparation Requirements
Rural proportion (DOEF0201)	Data in relation route lengths of lines / cables has been sourced from Smallworld. Data in relation to feeder categories has been sourced from FeederSTAT (Ergon's outage management system). Ergon's unregulated, isolated systems and sub-transmission feeders (according to the definition) have been removed from this calculation. Low voltage line/cable don't have a feeder attribute, therefore do not have a feeder category classification. It is assumed that will be classified as 'Non Rural'. Spans on multiple circuits are only calculated once. Information provided is Actual
Urban and CBD and Rural vegetation maintenance spans (DOEF0202-DOEF0203) **Total vegetation maintenance spans (DOEF0204)**	This information is collated from the vegetation contractors database systems in which all this information is recorded
Total number of spans (DOEF0205)	Total number of spans has been sourced from Smallworld. Information is Actual Information. DOEF0205 does not include service line spans. Spans on multiple circuits are only counted once.
Average urban and CBD vegetation maintenance span cycle (DOEF0206) **Average rural vegetation maintenance span cycle (DOEF0207)**	2018-19 average maintenance span cycle was calculated based on data sourced from the June monthly report for the Annual Vegetation Management Program (June 2019) taken from the Ellipse database (i.e. 2018-19 data was found in the June 2019 report). A methodology was employed whereby: • Average urban vegetation maintenance span cycle =

	(Sum of treated Urban vegetation zones cycle duration [Maintenance Schedule Task]/total number of Urban Vegetation Zones treated during regulatory (financial)year; • Average rural vegetation maintenance span cycle = (Sum or treated Rural vegetation zones cycle duration [Maintenance Schedule Task]/total number of Rural Vegetation Zones treated during regulatory (financial) year. The information provided is considered actual.
Average number of trees per urban and CBD vegetation maintenance span (DOEF0208) **Average number of trees per rural vegetation maintenance span (DOEF0209)**	This information is collated from the vegetation contractors database systems in which all this information is recorded
Average number of defects per urban and CBD vegetation maintenance span (DOEF0210) **Average number of defects per rural vegetation maintenance span (DOEF0211)**	This information is collated from the vegetation contractors database systems in which all this information is recorded.
Tropical proportion (DOEF0212)	The tropical proportion of Ergon Energy's network was based on network data sourced from the Smallworld GIS. The number of maintenance spans (refer to DOEF0205) occurring within hot humid summer and warm humid summer regions as sourced from the Bureau of Meteoroloogy (BOM) Information provided is considered Actual.
Standard Vehicle Access (DOEF0213)	The route line length without standard vehicle access was calculated by identifying the line length that falls outside the extents of the road reserve boundaries. Information provided is considered actual.

Bushfire Risk **(DOEF0214)**	The bushfire risk proportion of Ergon Energy's network was based on network data sourced from the Smallworld GIS. The number of maintenance spans (refer to DOEF0205) occurring within the high bushfire risk areas as sourced from the Queensland Fire and Rescue Service (QFRS). Information is considered Actual.

TABLE 3.7.3 - SERVICE AREA FACTORS

For 2018-19, an assessment of data from Smallworld was required.

The route length of all conductors and cable excluding service lines.

Spans on multiple circuits are only counted once.

Information provided for 2018-19 is considered actual in accordance with the AER's requirements.

12.5 Assumptions

No assumptions were made.

12.6 Estimated Information

Ergon Energy has provided ‘Actual Information’ (as per the AER’s defined terms)

12.7 Explanatory Notes

Not applicable.