Economic Benchmarking RIN
Basis of Preparation

2020-21

Part of Energy Queensland

Contents

BoP – 3.1 Revenue

Table 3.1.1 - Revenue Grouping by Chargeable Quantity

Table 3.1.2 - Revenue Grouping by Customer Type or Class

Table 3.1.3 - Revenue (penalties) Allowed (deducted) Through Incentive Schemes

Compliance with the 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 2020-21 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 12 (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 2020-21 is the Total SCS Revenue reported in Ergon Energy's 2020-21 Annual Reporting RIN less Jurisdictional scheme amounts and TUOS revenue. The TUOS component and the Jurisdictional component of Cross Boundary Revenue are also excluded from the Total SCS Revenue.

Recoverable works revenue is SCS revenue, however the statutory amount is adjusted out, and into the expense row to net off against the recoverable works expense. The recoverable works revenue is not part of the Total SCS revenue.

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 2020-21.

Ergon Energy notes that the AER has changed the variable numbers associated with this table in its revised templates for 2013-14 (consistent with 2020-21). Therefore, care should be taken when reviewing variable data for 2020-21 against submissions prior to 2013-14.

Revenue from Non-residential low/high voltage demand tariff customers

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

Sources

Source Data for Tables 3.1.1 & 3.1.2

For year 2020-21, data has been sourced from Ergon's 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 Source is PEACE monthly billing reports which include allocated Distribution Loss Factors Ergon Energy has sourced the Accrual data from the Ergon Energy's Annual Reporting RIN's for 2020-21.

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 (DREV0301), CESS (DREV0305) and STPIS (DREV0302) schemes - commencing from 1 July 2010.

EBSS and CESS payments for performance during 2010-15 are a component of the building blocks set in the relevant AER distribution determination. The EBSS payment for 2020-21 has been sourced from the AER's Final Decision Ergon Energy distribution determination 2020-25 Post Tax Revenue Model (PTRM) Public June 2020.

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 2020-21 Pricing Proposal.

Methodology

Table 1.1 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	Revenue from Fixed Customer Charges
Network DUos Fixed Charge$	
NDFCG	
Network DUoS Fixed Charge Generation$	
NDCUC	
Network DUoS Connection Unit Charge$	
NDIFC	
Network DUoS Inclining Fixed Charge$	
NDKVACC	Revenue from Contracted Maximum Demand Charges
Network DUoS kVA Capacity Charge$	
NDTDC	
Network DUoS Threshold Demand Charge$	
NDDCOP	
Network DUoS Demand Charge - Off Peak$	
NDDCP	
Network DUoS Demand Charge - Peak$	
NDKVACCOP	
Network DUoS kVA Capacity Charge - Off Peak$	
NDKVATDC	
Network DUoS kVA Threshold Demand Charge$	
NDKVAADC	Revenue from Measured Maximum Demand Charges

DCOS model or Billing reference	Benchmarking RIN Variable
Network DUoS kVA Actual Demand Charge$	
NDERPC	
Network DUoS Excess Reactive Power Charge$	
NDKVADCP	
Network DUoS kVA Actual Demand Charge Peak$	
NDMEKVADC	
Network DUoS Monthly Excess kVA Demand Charge$	
NDVC	Revenue from Energy delivery charges where time of use is not a determinant
Network DUoS Volume Charge$	
Residential and Business Inclining Block Tariff Band1$	
NDVCIBT	
Network DUoS Volume Charge Inclining Block$	
NDVCP	Revenue from On–Peak Energy Delivery charges
Network DUoS Volume Charge - Peak$	
NDVCOP	Revenue from Shoulder period Energy Delivery Charges
Network DUoS Volume Charge - Shoulder$	
NDVCOP	Revenue from Off–Peak Energy Delivery charges
Network DUoS Volume Charge - Off Peak$	

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 2020-21 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.

DREV0203 and DREV0204:

For 2020-21, 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.

DREV0110 - Metering Charges:

SCS is zero for 2020-21. All Metering is ACS in 2020-21.

ACS for 2020-21. The revenue is taken directly from the Income Statement in Ergon Energy's 2020-21 Annual Reporting RIN.

DREV0111 - Connection Charges:

SCS for 2020-21. This revenue is taken directly from the Income Statement in Ergon Energy's 2020-21 Annual Reporting RIN. It is the Contributions in SCS.

ACS for 2020-21. This revenue is taken directly from the Income Statement in Ergon Energy's 2020-21 Annual Reporting RIN. It is the total of the Connection services column.

DREV0112 - Public Lighting:

SCS for years 2020-21. Ergon Energy has sourced information from PEACE monthly billing reports.

ACS for 2020-21. The revenue has been taken directly from the Income Statement in Ergon Energy's 2020-21 Annual Reporting RIN. It is the total of the Public Lighting column.

DREV0113 - Revenue from Other Sources:

SCS, nothing to report.

ACS for 2020-21. The revenue has been taken directly from the Income Statement in Ergon Energy's 2020-21 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 2020-21 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 2020-21 Pricing Proposal. Consistent with advice received from the AER on 15 May 2019, 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 years factor impact).

The EBSS reward (DREV0301) has been calculated based on data in the AER's Final AER Decision Ergon Energy distribution determination 2020-25 PTRM Public June 2020. This was the PTRM used to set prices from 2020-21.

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

Ergon Energy has populated the variable 'DREV0305 Other' with the CESS reward included in the approved 2020-21 Total Annual Revenue (TAR) 2020-21. The CESS reward per the CESS model has been smoothed applying the X Factor within the Final Decision PTRM.

Assumptions

Revenue from Non-residential low/high voltage demand tariff customers

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

Estimated Information

For year 2020-21, Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variable in Template 3, except for the High/Low voltage data which is still considered estimated.

For DREV0203 and DREV0204 in table 3.1.2: 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.

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 2020-21. The impact of the change is a 0.3% decrease to DREV01 & DREV02 as a result of the net impact of accruals.

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.

Revenue from Non-residential low/high voltage demand tariff customers

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

BoP – 3.2 Operating Expenditure

Table 3.2.1 - Current OPEX Categories and Cost Allocations

Table 3.2.2 - OPEX Consistency - Current Cost Allocation Approach

Compliance with the RIN Requirements

Table 2. demonstrates how the information provided by Ergon Energy is consistent with each of the requirements specified by the AER.

Table 2.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Ergon Energy must report opex in accordance with the categories that they reported in response to their Annual Reporting Requirements.	Ergon Energy has reported opex in accordance with the categories reported in response to the Annual Reporting Requirements as detailed in RIN tables 3.2.1 and 3.2.2
Opex in table 3.2.1 must be prepared for all Regulatory Years in accordance with Ergon Energy's Cost Allocation Approach and directions within the Annual Reporting Requirements for the most recent completed Regulatory Year. For years where the Cost Allocation Approach and Regulatory Accounting Statements are consistent with those that applied in the most recent completed Regulatory year, total opex should equal that reported in the Regulatory Accounting Statements.	The amounts in RIN table 3.2.1 have been prepared in accordance with Ergon Energy's Cost Allocation Approach and directions within the Annual Reporting Requirements. Total opex equals that reported in the Annual Reporting RIN.
For table 3.2.2 Ergon Energy must report opex in accordance with the AER Variables and the Cost Allocation Approaches and reporting framework applied in the relevant Regulatory Years.	Ergon Energy has reported opex in the categories as defined in the AER EB RIN in accordance with its current Cost Allocation Approach. Total opex for SCS in this table aligns with that reported in the Annual Reporting 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, it 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.

Sources

Ergon Energy has sourced data from the SAP regulatory model (FIC3018), on the Enterprise Intelligence Platform (EIP) to comply with the AER approved Cost Allocation Method (CAM).

Methodology

Using data from the EIP model FIC3018 GL Regulatory Report, a mapping of AER reporting categories has been applied against functional areas, which is the same mapping process adopted for reporting the Annual Reporting RINs. For example: functional area 100007 Open Planned Maintenance is mapped to variable Preventive Maintenance.

Ergon Energy has sourced data from the EIP model FIC3018 GL Regulatory Report, created a table containing mappings between the functional areas to the EB RIN Variables (DOPEX0201 - DOPEX0206) and a query was run to extract costs against relevant variables.

Consistent with last year's methodology, ancillary service costs have not been reported in the ACS column for Network Services as it does not meet the definition of Network Services.

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.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) for 2020-21 in relation to all variables.

Explanatory Notes

Ergon Energy has used Actual Information, in accordance with the AER's definition, for all variables in Table 3.2.1 and 3.2.2.

The following explanations are provided in relation to RIN Table 3.2.1 Current opex categories and cost allocations:

- DOPEX0112 Debt Raising - Following the transfer of ownership of Ergon and Energex from the state to Energy Queensland Limited (EQL) on the 30 June 2016, transfers of debt for both DNSPs were made in order to comply with the Government Owned Corporations Regulation 2016 (Regulation). The share of the State Government debt pool held by the DNSPs prior to the formation of the group was a liability held by each DNSP. In accordance with the Regulation, all DNSP debt (Queensland Treasury Corporation Loans) was transferred back to the Government debt pool. It was then transferred to the parent entity (EQL) at the carrying amount, such that: A share of Queensland debt is held in the EQL parent entity. In 2021 a portion of QTC admin fees were representative of debt raising costs and these costs were allocated between the DNSPs based on their underlying PPE balances. Ergon Energy has therefore recognised its share of Debt raising costs this year.

Table 3.2.4 - OPEX for High Voltage Customers

Compliance with the 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.

Sources

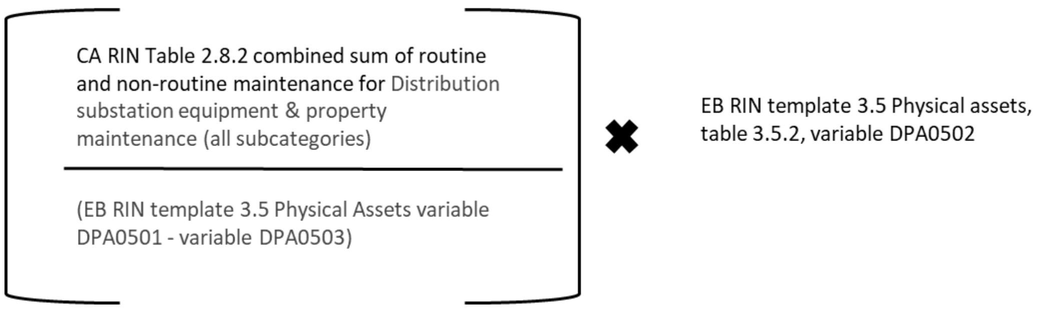
DOPEX0401 is a calculated field reliant on input from variables in the RIN templates detailed below. Please refer to the BoPs for those variables for a detailed explanation of the source data used.

CA RIN Template 2.8, table 2.8.2 Distribution substation equipment & property maintenance routine and non-routine maintenance expenditure for asset category, distribution substation transformers.

EB RIN Template 3.5, table 3.5.2, variables DPA0501, DPA0502 and DPA0503.

Methodology

Opex in RIN table 3.2.4 was estimated by first establishing a per MVA maintenance unit rate cost for distribution transformers and then multiplying this by the EB RIN reported distribution transformer capacity owned by High Voltage Customers to approximate the maintenance costs incurred by HV customers.



Assumptions

Ergon Energy assumes that the per MVA maintenance unit rate that applies to its distribution transformers would also apply to those owned by HV Customers. Please refer to the methodology section for more information.

Estimated Information

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

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.

Explanatory Notes

The method utilised to calculate the estimated opex for HV Customers has been updated this year. The approach used is considered a best estimate as it uses known per MVA maintenance operating costs for distribution transformers owned by Ergon Energy to approximate the costs that might have been incurred if transformers owned by HV customers where operated by Ergon Energy.

BoP – 3.2.3 Provisions

Table 3.2.3 - Provisions

Compliance with the RIN Requirements

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

Table 3.2: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Provisions must be reported in accordance with the principles and policies within the Annual Reporting Requirements for each Regulatory Year.	Provisions have been reported in accordance with the principles and policies within the Annual Reporting Requirements (AER defined term) for the Regulatory Year.
Financial information on provisions should reconcile to the reported amounts for provisions the Regulatory Accounting Statements for each Regulatory Year.	Financial information on provisions reconciles to the reported amounts for provisions in the annual RIN or Regulatory Accounts information provided to the AER

Note: 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 2020-21 against prior submissions.

Sources

Data has been sourced from the Ergon Energy general ledger. The FIC3018 SAP Regulatory model has been used to calculate the capex/opex split.

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 were swept to EQLD on a monthly basis via a reversing accrual journal up until May 2021. In June 2021 the mapping was changed so all transactions map directly into EQLD 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, then split between opex and capex using the actual opex/capex spend per the general ledger.

2. The Employee On Costs and the Super on Employee Entitlements Provision for Annual Leave and Long Service leave have no values in 2021 as those costs have now been directly costed to L3800 (Provision for Long Service Leave) and L3810 (Provision for Annual Leave).

3. The segments for Employee On Costs and Super on Employee Entitlements have been removed from the Rosetta Template.

4. 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) or new provisions for rehabilitation of leased premises which are now included in the value of a Right-of-Use asset, this is classified as Other.

5. 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.

6. 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.
7. Vested Sick Leave had a NIL balance in 2020 as the balance was kept at EQLD level permanently. In 2021, the balance was kept in Ergon and closing balance swept to EQLD at 30 June 2021.

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
- adjustments that resulted in decreased provisions are assumed to be unused amounts reversed.

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.

Explanatory Notes

There were no changes in accounting policies impacting Provisions during the 2020-21 year.

BoP – 3.3 Assets (RAB)

Table 3.3.1 - Regulatory Asset Base Values

Table 3.3.2 - Asset Value Roll Forward

Table 3.3.3 - Total Disaggregated RAB Asset Values

Compliance with RIN Requirements

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

- 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 in the 2020-25 Ergon Energy Final Determination.
- Where forecast values (additions and disposals) were used in relation to a decision on RAB values these amounts have been replaced with actual values which reconcile to amounts reported in the Annual Performance RIN for 2020-21.

A reconciliation between the opening balance for 2020-21 and the opening balance provided in the Final Decision – Ergon Energy Distribution Determination 2020-2025 PTRM is detailed in the table 4.1.

Table 4.1: Reconciliation of EB RIN Opening Balance to Final Decision PTRM Opening Balance

Table: Reconciliation EB RIN Opening Balance to Final Decision Distribution Determination PTRM Opening Balance							
Asset Class ($Millions)	EB RIN 2019-20 CB (A)	Less Actual 19-20 (B)	Plus Forecast 19-20 (C)	Less FY Rev Adj (D)	Plus FY Adj (E)	AER PTRM OB (F)	EB RIN 2020-21 OB (G)
Overhead Network Assets less than 33kV	4,410.88	(396.27)	226.54	(16.80)	-	4,224.35	4,394.08
Underground Network Assets less than 33kV	972.45	(15.36)	32.26	(5.92)	-	983.43	966.53
Distribution Substations and Transformers	1,775.86	(92.58)	105.22	(1.47)	-	1,787.03	1,774.39
Overhead Network Assets 33kV and Above	1,195.99	(49.65)	22.29	(0.61)	-	1,168.01	1,195.38

Underground Network Assets 33kV and Above	57.14	(1.59)	5.62	4.59	-	65.77	61.73
Zone Substations and Transformers	2,000.86	(74.59)	71.34	(11.62)	-	1,986.00	1,989.24
Easements	99.37	(0.13)	0.59	(0.90)	-	98.93	98.47
Meters	63.01	(0.66)	-	4.58	-	66.93	67.59
Other Assets with Long Lives	701.86	(52.51)	55.77	(5.65)	-	699.46	696.18
Other Assets with Short Lives	331.85	(56.96)	30.82	18.05	130.16	453.92	480.06
Total	**11,609.28**	**(740.30)**	**550.45**	**(15.75)**	**130.16**	**11,533.84**	**11,723.66**
Notes							
(G) EB RIN 2020-21 OB = A + D + E							
(F) AER PTRM 20-21 OB = A - B + C + D + E							

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. The mapping of the 28 disaggregated asset classes in the SCS RFM to the specified 10 asset categories of the EB RIN is detailed in table 4.2 below.

Table 4.2: RAB EB RIN Asset category definitions and mapping of EB RIN asset categories to annual RIN categories

EB RIN Asset Category	Definition	Mapped Ergon Energy Annual RIN Categories
Overhead network assets less than 33 kV (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Distribution Lines Low Voltage Services

Underground network assets less than 33 kV (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Distribution Cables
Distribution substations including transformers	Overhead and underground distribution substations. This includes ground mounted substations and pole mounted substations. This does not include zone substations.	Distribution Equipment Distribution Substation Switchgear Distribution Transformers
Overhead network assets 33 kV and above (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Sub-Transmission Lines
Underground network assets 33 kV and above (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Sub-Transmission Cables
Zone substations and transformers	Sites housing transformers involved in transforming power from high voltage input supply either directly from a TNSP or from Ergon Energy's own higher voltage lines - to distribution level voltages (e.g. 66 kV to 22 kV). This transformation can involve one step or multiple steps.	Substation Bays Substation Establishment Zone Transformers
Easements	An electricity easement is the right held by Ergon Energy to control the use of land near aboveground and underground power lines and substations. It holds this right to ensure the landowner's safety and to allow staff access to work on the power lines at all times.	Land & Easements (System) - combined
Meters	An electricity meter is a device that measures the amount of electric energy consumed by a residence, business, or an electrically powered device	Metering

Other assets with long lives	Assets with expected asset lives greater than or equal to 10 years that are not: • Overhead Distribution Assets (Wires and Poles) • Underground Distribution Assets (Cables) • Distribution Substations Including Transformers • Zone Substations and Transformers • Easements • Meters	Communications Pilot Wires Generation Assets Other Equipment Communications Buildings Land & Easements Land Improvements Buildings – capital works Equity Raising Costs
Other assets with short lives	Assets with expected asset lives less than 10 years that are not: • Overhead Distribution Assets (Wires And Poles) • Underground Distribution Assets (Cables) • Distribution Substations Including Transformers • Zone Substations and Transformers • Easements • Meters	Control Centre - SCADA IT Systems Office Equipment & Furniture Motor Vehicles Plant & Equipment In-house software

RAB values for each of the RAB Asset categories are exclusive of Capital Contributions.

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

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 2020-25 Distribution Determination. No RABs have been approved for any of Ergon Energy's other categories of ACS (Ancillary Network Services).

Asset 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

The value reported for the total disaggregated RAB asset values in table 3.3.3 for each respective asset category is derived as the average of the opening value and closing value reported in table 3.3.2. As the RAB values for each of the asset categories in template 3.3 are exclusive of capital contributions a zero value has been reported in line item DRAB13.

For the purposes of the EB RIN, data has been treated as actual information for the following reasons:

- The AER has determined the closing RAB values for 2014-15 in its Final Decision; and
- 2020-21 values are based on actual information from the AR RIN, with the exception of forecast depreciation for SCS which has been determined from the SCS RFM approved in the Final Decision.

Therefore, the data 'is not contingent on judgements and/or assumptions for which there are valid alternatives, which could lead to a materially different presentation', as per the definition of 'Actual Information' in the AER's EB RIN Instructions and Definitions.

Sources

Asset Value Roll Forward - SCS and ACS

For 2020-21, annual SCS and ACS (street lighting and Type 5-6 metering) financial information (additions, disposals and capital contributions) are sourced from the 2020-21 AER Annual Reporting RIN provided by Ergon Energy to the AER. Capex recognised in the SCS RAB and therefore reported in the T3.3 RIN Template is exclusive of capital contributions. Other inputs to the RFM have been sourced as follows:

- Forecast Depreciation – From the Final Decision – Ergon Energy Distribution Determination 2020-25 PTRM
- CPI information – From the Australian Bureau of Statistics (ABS) data series (eight capital cities December to December)
- WACC – From AER – Ergon Energy distribution determination 2020-2025 PTRM 2021-22 ROD Update.

The closing RAB values for each year from 1 July 2020 onwards will not align with the closing RAB values calculated each year in the AER's 2020-25 RFM. This is because the AER's 2020-25 RFM recognises actual 2019-20 additions and disposals for the first time at the end of 2024-25, whereas in the T3.3 RIN template the actual 2019-20 additions and disposals is recognised in the year in which it is incurred, and rolled forward through to 1 July 2020.

Asset 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. Consistent with the AER's definition of Network Services it is also necessary to exclude capital contributions (cash and in-kind.

Network Services data is derived from SCS data. Ergon Energy has established General Ledger activities within the corporate system to specifically report capital expenditure (capex) relating to connection services, in addition to ACS public lighting, connection, metering and ancillary network services. Capex relating to Network Services can then be derived by deducting connection services capex from the total SCS capex and mapped to the asset categories required by the EB RIN.

Connections expenditure includes:

- New shared network assets for Standard Asset Customers
- New dedicated connection assets for Standard Asset Customers
- 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.

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 2020-21 regulatory year are consistent with the SCS values in the 2020-21 Annual Reporting RIN, adjusted for movements in provisions.

Actual additions, disposals and capital contributions for 2020-21 associated with Type 5-6 Metering Services (to be removed from SCS data and hence Network Services data) are sourced from Ergon Energy's 2020-21 Annual Reporting RIN templates.

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

For 2020-21, the value of capital contributions (gifted assets and cash contributions) is sourced from the 2020-21 Annual Reporting RIN.

Total disaggregated RAB asset values

Data used to populate this table was extracted from the 2020-21 AER Annual Reporting RIN lodged by Ergon Energy to the AER.

Methodology

Asset Value

Ergon Energy has derived the SCS RAB values for EB RIN BOP 3.3 by rolling forward the approved RFM from the AER's Final Decision and updating for actual 2020-21 information from the AR RIN (capex and disposals), actual CPI, updated WACC and forecast depreciation. Each RAB asset category in the RFM has been rolled up into the EB RIN asset categories using the mapping provided in Table 2.

An RFM for Network Services (NS) was constructed from the RFM for SCS using historical RAB values, actual capex, actual disposals and actual CPI and forecast depreciation that has been adjusted to remove connection assets values.

An RFM for ACS was constructed from the Public Lighting and Metering RFMs from the AER's Final Decision, updated to include the actual capex, disposals, CPI and depreciation and updated WACC for 2020-21.

Standard Control Services

1. The RFM was based on the Final Decision – Ergon Energy Distribution Determination 2020-2025. The RFM starts with the closing RAB values for the 2019-20 regulatory year adjusted for actuals and includes these values as the Opening Asset Value.
2. Data for 2020-21 was sourced from the AR RIN and depreciation from the Final Decision – Ergon Energy Distribution Determination 2020-2025 PTRM. Consistent with the Final Decision RFM, total capitalised provision movement has been deducted from the actual capex of each asset category proportionately. Capital contributions are excluded from the RAB. As a result, capital contributions have been excluded from capex in the input sheet of the RAB RFM and the variable DRAB13 is reported as nil
3. Using the input values in step 2) above, the RFM calculates the following for each asset category for regulatory year 2020-21:
4. Nominal Opening Regulated Asset Base – The opening balance reflects the 2019-20 closing Regulated Asset Base amended for:
   - Final year revenue adjustments for any variances between forecast and actual capex of the last year of the previous control period
   - Asset adjustment representing ICT assets of $130M. The digital function now sits within the DNSP rather than being provided through a 3rd party.

These values are all nominal.

- Nominal Actual Inflation on Opening RAB. Calculated as the Nominal Opening Regulated Asset Base multiplied by CPI. A manual adjustment is made to this value to reflect the fact that no adjustment is factored into the revenue adjustment for inflation on opening balance due to differences in forecast and actual capex for the last year.

  - Nominal Forecast Straight-line Depreciation Extracted from the Final Decision PTRM.
  - Nominal Actual Gross Capex. Calculated as the actual real term capex with half WACC adjustment and adjusted by actual CPI (1 year lagged). Capex is adjusted for movement in provisions relating to capex.
  - Nominal Actual Disposal. Calculated as the actual real term disposals with half WACC adjustment and adjusted by actual CPI (1 year lagged).

- The values calculated in step 3) above then form the variables stated in EB RIN tables 3.3.1, 3.3.2 and 3.3.3. Table 3.3.1 contains the aggregated RAB values, Table 3.3.2 disaggregates these values into each asset category specified in the EB RIN and Table 3.3.3 contains the yearly average RAB value of the disaggregated asset categories.

EB RIN Table 3.3.1 - Regulatory Asset Base Values

Aggregated RAB values

- Opening value - Nominal Opening Regulated Asset Base
- Inflation addition - Nominal Actual Inflation Opening RAB
- Straight line depreciation - Nominal Forecast Straight-line Depreciation
- Actual additions (recognised in RAB) - Nominal Actual Gross Capex
- Disposals - Nominal Actual Disposal
- Closing value for asset value - Nominal Opening Regulated Asset Base (for next regulatory year)

EB RIN Table 3.3.2 - Asset Value Roll Forward

RIN Table 3.3.2 disaggregates each of the values in RIN Table 3.3.1 into the individual asset categories specified in the EB RIN. These EB RIN asset categories are made up of one or more asset categories from the RFM. For the mapping of these refer to Table 2.

EB RIN Table 3.3.3 - Total disaggregated RAB asset values

EB RIN Table 3.3.3 - Total disaggregated RAB asset values are calculated as the average of the opening and closing RAB totals for each EB RIN asset category for each year by applying the formula below.

Network Services (NS)

Network Services (NS) are a subset of Standard Control Services that excludes Connection Services, Metering services, Fee Based and Quoted Services and Public Lighting Services. Accordingly, the NS RFM is identical to SCS in its construction and calculation; however, the inputs are adjusted for the following:

- The RFM opening values were adjusted to include only those values relating to NS. Where a respective asset category was identified as not to incorporate connection services and the balance did not reflect the SCS balance the network asset service category was adjusted to align with the reported SCS balance.
- The capex relating to connection assets was deducted from the capex in the SCS RFM to derive the NS values. The capitalised provision movement allocated to each asset category for SCS has been allocated to NS based on the proportion of NS capex to SCS capex for that asset category.
- The value of disposals for NS is taken to be the same as the SCS asset categories as connection asset disposals are not considered material.

Alternative Control Services

Ergon Energy's ACS includes public lighting, connection, metering and ancillary network services. As the AER only approved a RAB for public lighting and metering services, only assets relating to these services are included and reported in the EB RIN Assets BOP for ACS, consistent with the EB RIN Instructions and Definitions.

CPI and WACC are based on those used for the SCS.

Capex for ACS was sourced directly from the AR RIN and/or supporting workings.

Assumptions

No assumptions were made.

Estimated Information

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

Explanatory Notes

On 25 November 2020, Ergon Energy resubmitted the following tables to the AER for years 2015-16 to 2019-20:

- EB 3.3.1 Regulatory Asset Values, 2015-16 to 2019-20
- EB 3.3.2 Asset Value Roll Forward, 2015-16 to 2019-20
- EB 3.3.3 Total Disaggregated RAB Asset Values, 2015-16 to 2019-20

The reason for the resubmission was disclosed in the 2019-20 BOP against Opening RAB Values, and is also provided below for completeness:

- Network Services is a subset of Standard Control Services (SCS), whereby certain assets are excluded from the SCS RAB to determine the Network Services RAB. In updating the SCS RAB for the Final Distribution Determination for 2020-2025 it was identified that a number of asset category balances for network services were in excess of the SCS RAB value. Where the respective asset category did not incorporate any connection service expenditure the network services asset category balance was adjusted to align with the reported SCS balance.

- Further, through the updating process it was revealed that the network services RAB had inadvertently been understated with the removal of gifted assets being duplicated. In preparing the SCS RAB, all capital contributions are excluded from additions, in accordance with the RIN requirements, and therefore are excluded from the SCS RAB balances. In determining the Network Services RAB balances, the SCS RAB additions were reduced by removing contributions from the SCS additions. Given all contributions had been excluded from the SCS RAB, this resulted in an understatement of the Network Services additions and balances. The understatement of Network Services has occurred throughout the 2015-20 regulatory period. The cumulative impact on Network Services RAB additions throughout the period occurred as follows:

  - 2015-16 - $10.5M
  - 2016-17 - $2.1M
  - 2017-18 - 15.9M
  - 2018-19 - 44.2M
  - 2019-20 - 59.6M
  - Total - $132.3M.

The AER acknowledged receipt of Ergon Energy’s resubmission on 27 November 2021 by email and stated if any additional information is required, this will be further communicated after the AER’s assessment is completed. To date, no further communication has been received from the AER in relation to this matter.

Accounting Policies

On a regular basis, a review is performed to monitor accounting standard updates and new standards issued by the Australian Accounting Standards Board to assess the impact on Ergon Energy. Changes are advised to the Audit Committee and implemented where required and the associated Ergon Energy accounting policies are updated accordingly.

There are no material impacts from changes in accounting standards for the 2021 financial year, and subsequently no accounting policy changes that may impact the RIN.

Table 3.3.4 - Asset Lives (estimated Residual Service Life)

Table 3.3.4 - Asset Lives (estimated Service Life of New Assets)

Compliance with the RIN Requirements

The AER requires Ergon Energy to report asset life information in accordance with the asset categories defined in the EB RIN BOPs. The definitions of these asset categories can be found in BoP 3.3.1 Asset (RAB) Values.

The table below demonstrates how the information provided by Ergon Energy is consistent with each of the requirements specified by the AER.

Table 4.3 Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
New assets are assets installed in the most recent regulatory reporting year. The expected service life of new assets is the estimated period after installation of a new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. This may not align with the asset's financial or tax life.	Ergon Energy has reported the service life of new assets in the RAB based on the RAB RFM from the AER's Final Decision: Ergon Energy determination 2020-21 to 2024-25. This represents the estimated time during which the asset is capable of delivering the same effective service as it could at installation date.
Ergon Energy must report a current estimation of the weighted average remaining time expected that an asset class (as per DRAB1501 to DRAB1509) will deliver the same effective service as that asset class did at its installation date.	Ergon Energy has reported the estimated residual service life of all RAB asset categories as the weighted average of all assets contained in that category. Similar to the estimated service lives, these figures are based on the Final Decision. All weighted averages have been calculated on the assets' share of the RAB and their expected asset lives. Ergon Energy has also divided asset life data into NS, SCS and ACS. This was done in line with the methodology outlined for RAB values.

Sources

Asset life data has been sourced from the RFMs from the AER's Final Decision. Additional inputs have been sourced as follows:

- CPI information - Sourced from the Australian Bureau of Statistics (ABS) data series A2325846C (eight capital cities from December to December) in line with the AER approach and regulatory reporting
- Capex and disposals - Sourced from the Annual Performance (AP) RIN

- WACC - Sourced from the Final Decision, updated for the return on debt component of the WACC every April in line with the AER guidance.

The table below demonstrate the sources from which Ergon Energy obtained the required information.

Table 4.4 Data Sources RIN Table 3.3.4.1 asset lives: estimated service life of new assets

Variable Code	Variable	Source
DRAB1401	Overhead network assets less than 33kV (wires and poles)	Final Decision, AR RIN, ABS
DRAB1402	Underground network assets less than 33kV (cables)	Final Decision, AR RIN, ABS
DRAB1403	Distribution substations including transformers	Final Decision, AR RIN, ABS
DRAB1404	Overhead network assets 33kV and above (wires and towers/poles etc.)	Final Decision, AR RIN, ABS
DRAB1405	Underground network assets 33kV and above (cables, ducts etc.)	Final Decision, AR RIN, ABS
DRAB1406	Zone substations and transformers	Final Decision, AR RIN, ABS
DRAB1507	Meters	Final Decision, AR RIN, ABS
DRAB1408	"Other" assets with long lives	Final Decision, AR RIN, ABS
DRAB1409	"Other" assets with short lives	Final Decision, AR RIN, ABS

Methodology

Asset Lives

Ergon Energy has calculated the expected service life of new assets and the residual service life of assets based on the RFMs from the Final Decision. These RFMs were updated for the 2019 actual information (capex and asset disposals) from the AR RIN.

Standard Control Services

The estimated service life of new assets was calculated using the standard service life published in the Final Decision RFM. This service life was applied to 2021. The asset life categories in the RFM were then aggregated into the categories required for the EB RIN. The aggregation used a weighted average of each of the applicable asset categories, weighted by their 2020 closing RAB value. For the mapping of the Final Decision RFM asset categories to the EB RIN categories refer to BoP 3.3.1 Asset (RAB) Values.

The residual service life of RAB assets was calculated applying the remaining life calculation in the AER RFM. The calculation applies estimated standard lives for additions and residual lives of existing assets. This BOP relies on information calculated in the RAB RFM for SCS, ACS and NS, as detailed in Basis of Preparation for Asset (RAB) Values. The RFM extracts the following information for each asset category and regulatory year:

- Standard Asset Life
- Opening RAB Value (2020)
- Opening RAB Residual Asset Life (2020)
- Acquisitions (assumed average mid-year capitalisation and adjusted for half year WACC)
- Disposals (assumed average mid-year disposal and adjusted for half year WACC)
- Depreciation
- Adjustments (adjustments made for 2019-20 to account for the difference between actual and forecast capex for 2015).

The average residual life for each asset class is calculated by rolling forward the RAB values from the prior year. This is calculated as the weighted average of:

- The prior year's average residual life minus one
- The standard life of any new acquisitions.

The weightings are based on the RAB value of the current year's assets (prior year RAB minus disposals, depreciation and applicable adjustments) and the newly acquired assets.

With the residual average asset lives calculated for each regulatory year, the asset categories are then combined into the EB RIN asset categories. The EB RIN residual asset life is calculated for each year as the average of the RFM asset lives weighted by the yearly RAB value of each RFM asset category. The mapping of the RFM asset categories to the EB RIN asset categories can be found in BoP 3.3.1 Asset (RAB) Values.

Network Services

NS are defined as a subset of SCS. NS are identical to SCS with the exclusion of those assets specified by the AER in the definition of Network Services contained in the Instructions and

Definitions for the EB RIN (e.g. Connection assets). For details of the construction of the NS RAB values refer to Basis of Preparation for Asset (RAB) Value.

The Asset Life calculation for NS was constructed in an identical manner to that for SCS however it draws its data from the NS RAB. The methodology for preparing the estimated service life of new assets and the residual service life of RAB assets is identical to steps 1 to 4 in SCS above.

Alternative Control Services

From 1 July 2015, Ergon Energy's ACS includes public lighting, connection, metering and ancillary network services. As the AER only developed a RAB for public lighting and metering services based on the limited building block approach, only these services are included in the RFM, consistent with the EB RIN Instructions and Definitions.

The methodology of calculating the estimated service life and residual service life was identical to SCS and NS.

Assumptions

Standard service life of RAB assets is constant and equal to those specified in the Final Decision.

Estimated Information

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

Explanatory Notes

Ergon Energy for the current regulatory period has adopted the calculation of remaining lives as applied in the AER RFM. The approach to the calculation is outlined in the method section above. This is a departure from the approach applied in the previous regulatory period which extracted data from the corporate fixed asset register and mapped to the respective EB RIN asset categories. The change in approach was undertaken on the basis of aligning the methods of Energex and Ergon.

EB RIN Asset Category Definitions and Mapping

Table 4.5 RAB EB RIN Asset category definitions and mapping of EB RIN asset categories to annual RIN categories

EB RIN Asset Category	Definition	Mapped Ergon Energy Annual RIN Categories
Overhead network assets less than 33 kV (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Distribution Lines Low Voltage Services
Underground network assets less than 33 kV (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Distribution Cables
Distribution substations including transformers	Overhead and underground distribution substations. This includes ground mounted substations and pole mounted substations. This does not include zone substations.	Distribution Equipment Distribution Substation Switchgear Distribution Transformers
Overhead network assets 33 kV and above (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Sub-Transmission Lines
Underground network assets 33 kV and above (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Sub-Transmission Cables
Zone substations and transformers	Sites housing transformers involved in transforming power from high voltage input supply either directly from a TNSP or from Ergon Energy's own higher voltage lines - to distribution level voltages (e.g. 66 kV to 22 kV). This transformation can involve one step or multiple steps.	Substation Bays Substation Establishment Zone Transformers

Easements	An electricity easement is the right held by Ergon Energy to control the use of land near aboveground and underground power lines and substations. It holds this right to ensure the landowner's safety and to allow staff access to work on the power lines at all times.	Land & Easements (System) - combined
Meters	An electricity meter is a device that measures the amount of electric energy consumed by a residence, business, or an electrically powered device	Metering
Other assets with long lives	Assets with expected asset lives greater than or equal to 10 years that are not: • Overhead Distribution Assets (Wires and Poles) • Underground Distribution Assets (Cables) • Distribution Substations Including Transformers • Zone Substations and Transformers • Easements • Meters	Communications Pilot Wires Generation Assets Other Equipment Communications Buildings Land & Easements Land Improvements Buildings – capital works Equity Raising Costs
Other assets with short lives	Assets with expected asset lives less than 10 years that are not: • Overhead Distribution Assets (Wires And Poles) • Underground Distribution Assets (Cables) • Distribution Substations Including Transformers • Zone Substations and Transformers • Easements • Meters	Control Centre - SCADA IT Systems Office Equipment & Furniture Motor Vehicles Plant & Equipment In-house software

Accounting Policies

On a regular basis, a review is performed to monitor accounting standard updates and new standards issued by the Australian Accounting Standards Board to assess the impact on Ergon

Energy. Changes are advised to the Audit Committee and implemented where required and the associated Ergon Energy accounting policies are updated accordingly.

There are no material impacts from changes in accounting standards for the 2021 financial year, and subsequently no accounting policy changes that may impact the RIN.

BoP – 3.4 Operational Data

Table 3.4.1 - Energy Delivery

Compliance with the 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 fields 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).

Sources

TABLE 3.4.1 - ENERGY DELIVERY

Energy Delivery & Energy Grouping - Delivery by Chargeable Quantity

- For year 2020-21, 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 updated 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 2020-21, 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.

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.

Assumptions

No assumptions were made.

Estimated Information

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

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.

Table 3.4.2 - Customer Numbers

Compliance with the RIN Requirements

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

- Ergon Energy does not have any feeders classified as 'DOOPCN0201' for CBD Network.
- 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.

Sources

Table 3.4.2 - Customer Numbers Distribution Customer Numbers by Customer Type or Class

- Ergon Energy Network 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 Network as their DNSP.

Distribution Customer Numbers by Network Location

- Ergon Network 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.

Methodology

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. Each NMI has been counted as a separate customer.

The table below demonstrates how each criteria is calculated:

3.4.2.1 - Distribution customer numbers by customer type or class	
Residential customer numbers	If NMI status = Active & De-energised, is Metered, not demand, Customer Class code = Residential
Non residential customers not on demand tariff customer numbers	If NMI status = Active & De-energised is Metered, not demand, not Customer Class code = Residential
Low voltage demand tariff customer numbers	If NMI status = Active & De-energised, is Metered,demand tariff=Yes, connection type = Low voltage
High voltage demand tariff customer numbers	If NMI status = Active & De-energised, is Metered,demand tariff=Yes, connection type = High voltage
Unmetered Customer Numbers	If NMI status = Active & De-Energised, with a NMI Rage of '3093000000' AND '3094999999' , '3090000000' AND '3092999999' THEN 'UMS'
Other Customer Numbers	If NMI status = Active & De-energised is Metered, demand, NOT HIGH or LOW Voltage

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
- 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.

Assumptions

Due to major tariff changes effective since 1 July 2020, a number of residential customers are now on demand tariffs and this number is expected to grow due to the mandatory assignment of demand tariffs for new connections and customer completing alterations. From 1 July 2021 it is also mandatory for all customers with a digital meter to be assigned a demand tariff.

As a result, the number of customers reportable under DOPCN0103 Low voltage demand tariff customer numbers increased. As these are known residential customers, a correction is applied to ensure consistency in reporting of residential customers and low voltage demand tariff customer numbers.

Estimated Information

Not applicable. Ergon Energy has provided actual information.

Explanatory Notes

High Voltage demand tariff customer numbers

- High Voltage demand tariff customer numbers have been reviewed for consistency internally and issues were identified whereby distribution loss factors (DLFs) used to identify HV customers were incorrectly flagging some customers as LV instead. This has been corrected.

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.

Table 3.4.3 - System Demand

Compliance with the RIN Requirements

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 (i.e. DOPSD0305, DOPSD0310 and DOPSD0314). All other fields shaded yellow indicating a mandatory data field have 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 Network charges customers for Maximum Demand supplied.

In instances where Ergon Network cannot distinguish between contracted and measured Maximum Demand, demand supplied is allocated to contracted Maximum Demand. This includes a large number of customers on the Threshold Demand tariffs.

Ergon Network commenced charging major customers on a kVA (MVA) basis as of 1 July 2015 and all major customers are charged on a kVA basis by 30 June 2020. Ergon Network also commenced charging SAC Large customers that publish a KVA channel on a kVA basis as of 1 July 2020 and this is reflected in a reduction in the reported kW values and increase in reported kVA values in the 2020-21 templates.

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 Network charges customers for Maximum Demand supplied. This was also confirmed following AER review of Ergon Energy Network'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 Network 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 Network only charges customers for demand based on MWs then 0s should be input into table 3.4.3.7.

Sources

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 derived power factor (pf) data (i.e. real and apparent power) from the Ergon Energy DNSP central data repository (NODW), which in-turn, extracts historical metering reading data across its network of assets over half hourly intervals. In the absence of any directly metered data sources for individual assets, a suitable meter is sourced upstream in the network as an alternative (e.g. supplying feeder, transformer or substation).

Table 3.4.3 - System Demand

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

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

Methodology

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:

- The days that are unlikely to produce a peak demand were excluded
- Multiple seasons of data were used
- 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 and the Christmas shutdown period.
- Daily historical BOM temperatures are passed through each equation and maximum annual demand is obtained
- 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:

- The peak demand data for each Connection Point was aggregated to find for total non-coincident peak
- The Connection Point coincident MW and MVA values were calculated from as recorded system raw demand
- The Ergon Energy System level POE values will be different from the temperature corrected figures calculated at the individual Connection Point (or Zone Substation level) and aggregated to form a system total number - as the aggregated numbers are not only based on peaks from either the summer or the winter, but there are also differences in the

methodology of temperature correction, with the POE methodology used at the Ergon Energy System level incorporating more explanatory variables - like economic and demographic drivers.

- The non-coincident zone substation summated demands are from any half hour, and therefore diversity of load peaks & losses need to be accounted for in any comparison between aggregated zone substation and connection point demands.

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

- The demand data for each zone substation was aggregated to find for total non- coincident peak
- The POE adjustment is based on the standard weather adjustment process using the best fit from BOM sites and is recorded in SIFT
- These adjustments are then applied to the recorded demands and then aggregated to total values in the appropriate row in MVA.

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 kVA 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, as shown in the equation below:

DOPSD0301 = DOPSD0110/DOPSD0210

where:

- DOPSD0110 - Coincident Raw System Annual Maximum Demand (MW)
- DOPSD0210 - Coincident Raw System Annual Maximum Demand (MVA)

Power Factor Conversions

Generally, the power factor is calculated by the following equation:

Power Factor = Real Power (kW)/Apparent Power (kVA)

The following steps are undertaken in procuring the average power factor:

1. The ‘average power factor’ is calculated for each of the feeder categories according to Table 3.4.3.5. Within each category, individual feeders are identified and suitable metering readings

are procured for real and apparent power historically for the target year sample. For each individual feeder's historical readings the equivalent power factor is derived

2. Once each individual feeder's historical equivalent power factor is obtained it is checked for consistency and cleansed if necessary
3. Approved historical power factors for each individual feeder are then averaged over the target period (i.e. obtaining a yearly average)
4. To derive the final 'average power factor' for an entire population of a categorised feeder group, each of the individual feeder's yearly average power factors are averaged again for a final figure.

Table 3.4.3 - System Demand

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

Billed capacity and demand values based on the PEACE billing item 'sub-charge code' are extracted from the PEACE billing system by NMI by month for the RIN reporting period. The data extracted includes the tariff billed and the PEACE system sub-charge code which identifies the charge as either a capacity or demand charge. A number of PEACE sub-charge codes are sourced in the extract and are further summarised into 1 of 5 classifications

1. kw_threshold_demand (DOPSD0401)
2. kw_actual_demand (DOPSD0402)
3. kva_capacity_demand (DOPSD0403)
4. kva_threshold_demand (DOPSD0403)
5. kva_actual_demand (DOPSD0404)

consisting of the PEACE sub-charge codes as follows

DOPSD0401 is kw_threshold_demand

- NDTDC - DUoS Threshold Demand Charge

DOPSD0402 is kw_actual_demand

- NDDCP - DUoS Demand Charge - Peak
- NDDCOP - DUoS Demand Charge - Off Peak

DOPSD0403 is kva_capacity_demand and **kva_threshold_demand**

- NDKVACC - DUoS kVA Capacity Charge
- NDKVATDC - DUoS KVA Threshold Demand Charge

DOPSD0403 is kva_actual_demand

- NDKVAADC - DUoS kVA Actual Demand Charge
- NDKVADCP - DUoS kVA Actual Demand Charge Peak
- NDKVACCOP - DUoS kVA Actual Demand Charge - Off Peak
- NDMEKVADC - DUoS Monthly Excess kVA Demand Charge

All values reported on the template are aggregated NMI level data where only the single annual maximum peak for each NMI is summated into the reported total. This is best explained in detail by way of example:

- Month 1 measured demand = 754 kVA
- Month 2 measured demand = 818 kVA
- Month 3 measured demand = 780 kVA
- Month 3 measured demand = 660 kVA
- 818 kVA is the maximum of all monthly values and this is the value for this specific NMI included in the aggregated total of all customers annual maximum demands

Where a specific NMI has churned from one demand tariff to another during the year, only the single annual maximum demand value scanned across both tariffs is recorded, and it is reported against the classification applicable to the tariff – sub-charge combination where the maximum was recorded

Threshold demand charges refer to specific tariffs in the SAC Large customer group where demand is charged only on that portion of measured demand above a set threshold applicable to each tariff. The 3 tariff types and threshold values are as follows:

1. Demand Large (*DLT*) 400 kW or 450 kVA per month
2. Demand Medium (*DMT*) 120 kW or 135 kVA per month
3. Demand Small (*DST*) 30 kW or 35 kVA per month

If measured demand maximum for a specific customer in a single month does not exceed the threshold demand value for the tariff, then 0 demand is charged and recorded. Charges for maximum demand that come into effect when a set level of demand is reached have been classified as Contracted Maximum Demand Charges and only the actual demand value above threshold is reported. An example based on SAC Large tariff DLT with a 400 kVA demand threshold is shown below:

    - Month 1 measured demand = 380 kVA therefore 0 kVA is included in the analysis
    - Month 2 measured demand = 418 kVA therefore 18 kVA is included in the analysis
    - Month 3 measured demand = 435 kVA therefore 35 kVA is included in the analysis
    - Month 4 measured demand = 410 kVA therefore 10 kVA is included in the analysis
    - 35 kVA is the maximum of all monthly values and so this is the value for this specific NMI included in the aggregated total of all customers annual maximum demands

- DOPSD0401 - Summated Chargeable Contracted Maximum Demand (MW)
    - SAC Large tariffs DLT, DMT and DST on sub-charge code NDTDC
    - DOPSD0402 - Summated Chargeable Measured Maximum Demand (MW)
    - SAC Large tariff STOUD on sub-charge codes NDDCP or NDDCOP
    - SAC Small tariffs BDEM, BTDEM, RDEM and RTDEM on sub-charge code NDDCP
- DOPSD0403 - Summated Chargeable Contracted Maximum Demand (MVA)
    - ICC tariffs on sub-charge code NDKVACC
    - CAC tariffs on sub-charge code NDKVACC
    - SAC Large tariffs DLT, DMT and DST on sub-charge code NDKVATDC
- DOPSD0404 - Summated Chargeable Measured Maximum Demand (MW)
    - ICC tariffs on sub-charge code NDKVAADC
    - CAC tariffs on sub-charge code NDKVAADC
    - CAC STOUD tariffs on sub-charge codes NDKVADCP and NDKVACCOP
    - SAC Large tariff LTOUD on sub-charge code NDKVADCP and NDMEKVADC

Assumptions

Power Factor Conversions

Feeder current direction is ignored to ensure that the average power factor calculation average is not adversely affected (i.e. absolute values of meter readings are utilised)

Feeders considered in the power factor population must be in operation and not inactive during the examination period. Similarly, feeder meter readings reflecting zeros or 'no data' consider the associated asset as not in operation and are subsequently discarded from final averaging power factor calculations

Meter tolerances are imposed to counter metering misreads or mis-calibrations and to prevent unrealistic power factor measures beyond unity (i.e. no power factor readings > 1)

In the absence of a dedicated feeder meter the closest and most suitably available meter found upstream is assigned for the meter reading.

Estimated Information

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

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.

Power Factor Conversions

Some volatility exists for the average power factor calculations and metering sources catering for both the 3.3kV and 6.6kV feeder categories as these have very small asset populations and/or are not directly metered and require examination of their upstream sources. In addition, this sensitivity is further impacted as these asset classes usually supply pumping stations which are highly reactive and experience seasonal operational schedules causing performance behaviours that can be deemed as erratic in their trending history.

Ergon Energy has made concerted efforts to collate and present the most comprehensive data set of SWER feeders for the RIN submission as opposed to the sampled populations of previous submissions. It is noted that as the majority of feeders in this category are not directly metered and the next available upstream meter is utilised to obtain a suitably derived power factor.

For procuring the average power factor for LV feeders, Ergon Energy recognises this category as having a significant asset feeder population with no directly established metering monitoring. To overcome this issue an accounting of distribution transformers was made noting the number of customers supplied and linking upstream supply substations for meter reading information to form a suitable representation of contributing power factor readings.

BoP – 3.5 Physical Assets

Table 3.5.1 - Network Capacities

Compliance with the 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.

DPA0301 Circuit capacity (MVA): Overhead low voltage distribution

Ergon Energy has provided estimated typical or weighted average capacity for overhead low voltage class within our network as prescribed by the AER, under normal circumstances taking account of limits imposed by thermal or by voltage drop considerations as relevant.

Capacity has been provided in an MVA measure.

On 4 February 2015, the AER provided (at Ergon Energy's request) the following clarification with regards to requirements in respect of reporting requirements for these tables:

We are not requesting separate weighted average capacities for summer and winter. We are requesting the weighted average capacity for the whole network in summer if the majority of that network experiences maximum demand in summer. Conversely, we are requesting the weighted average capacity for the whole network in winter if the majority of that network experiences maximum demand in winter. That is, we are requesting the weighted average MVA capacity circuit capacity calculated using the capacities (under system normal conditions) at the time of overall system Maximum Demand.

Further to this, on 3 December 2013, the AER provided the following clarification to NSPs:

...variables contained within [Tables 6.1.1 and] 6.1.3 do not include the length or capacity of service lines. The correct, compliant completion of Tables 6.1.1 and 6.1.3 is to report the circuit length and circuit capacity excluding the circuit length and circuit capacity of service lines.

A stakeholder has asked whether two sets of lines that run on different sets of poles (or towers) but share the same easement should count as one route or two for the variable DOEF0301. We confirm that in this instance the lines are to be counted separately. The correct, compliant response to the variable DOEF0301 where two sets of lines share the same easement but run on separate sets of poles (or towers) is to count these lines as separate routes when reporting total route line length.

The entry field which is shaded yellow indicating a mandatory data field has been populated.

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

Ergon Energy has provided estimated typical or weighted average capacities for each of the listed overhead voltage classes (3.5.1.3) and underground voltage classes (3.5.1.4) within our network as prescribed by the AER, under normal circumstances taking account of limits imposed by thermal or by voltage drop considerations as relevant.

Capacity has been provided in an MVA measure.

On 4 February 2015, the AER provided (at Ergon Energy's request) the following clarification with regards to requirements in respect of reporting requirements for these tables:

We are not requesting separate weighted average capacities for summer and winter. We are requesting the weighted average capacity for the whole network in summer if the majority of that network experiences maximum demand in summer. Conversely, we are requesting the weighted average capacity for the whole network in winter if the majority of that network experiences maximum demand in winter. That is, we are requesting the weighted average MVA capacity circuit capacity calculated using the capacities (under system normal conditions) at the time of overall system Maximum Demand.

Further to this, on 3 December 2013, the AER provided the following clarification to NSPs:

Variables contained within [Tables 6.1.1 and] 6.1.3 do not include the length or capacity of service lines. The correct, compliant completion of Tables 6.1.1 and 6.1.3 is to report the circuit length and circuit capacity excluding the circuit length and circuit capacity of service lines.

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, DPA0402, DPA0404, DPA0407]. All entry fields which are shaded yellow indicating mandatory data fields have been populated.

Sources

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres)

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.

DPA0301 Circuit capacity (MVA): Overhead low voltage distribution

Refer to the methodology section.

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
- Ergon Energy Plant Rating Guidelines
- Olex cable manufacturer catalogue calculations.

Methodology

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres)

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.

DPA0301 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.

As per previous submissions unknown overhead low voltage conductors have been assumed to be small copper conductor (0.080").

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

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 have been given the same rating;
- Cable ambient air temperatures were calculated from spatial analysis with Ergon Energy Climate Zones;
- Cable ground temperatures were calculated from spatial analysis with 9 BOM Weather stations (nearest);
- Unknown Voltage & Phase attributes were calculated from cable characteristics;
- Cable 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.

Assumptions

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres)

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres): It is assumed that the maximum length of a service line is 50m.

DPA0301 Circuit capacity (MVA): Overhead low voltage distribution

Not applicable.

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

As per previous submissions unknown overhead low voltage conductors have been assumed to be small copper conductor (0.080").

Estimated Information

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres)

Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in tables 3.5.1.1 & 3.5.1.2 Circuit length (kilometres).

DPA0301 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.

As per previous submissions unknown overhead low voltage conductors have been assumed to be small copper conductor (0.080").

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

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA): Ergon Energy has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this Template. Ratings are based on the actual conductor length including sag.

Explanatory Notes

Table 3.5.1.1 & 3.5.1.2 Circuit length (kilometres): Not applicable.

Circuit capacity (MVA): Overhead low voltage distribution:

Increases to the low voltage weighted MVA rating has originated from Ergon Energy's UGIS project inserting approximately 160,000 new low voltage Overhead services assigned with generic value.

Table 3.5.1.3 & 3.5.1.4 Circuit Capacity (MVA)

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.

Table 3.5.2 - Transformer Capacities

Compliance with the RIN Requirements

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

The entry field which is shaded yellow indicating a mandatory data field has been populated.

Distribution transformer capacity owned by Ergon Energy (DPA0501) utilises the nameplate continuous rating including forced cooling.

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

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."

Cold Spare Capacity (Distribution Transformer and Zone Substation)

The entry field which is shaded yellow indicating a mandatory data field has been populated.

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) when considering distribution and substation transformers respectively, using nameplate records.

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 (i.e. HRT – Heat Run Test). Where testing records are not available the transformer nameplate rating is reported.

Cold Spare Capacity, for this category, represents the total capacity of transformers owned by Ergon Energy but not currently in use and includes assets held in inventory spares, substation standby transformers or other transformers that do not run under normal operating conditions. Cold spare capacity is included in the Total Zone Substation Transformer Capacity (DPA0604).

Sources

Distribution Transformer Total Installed Capacity

DPA0501 - Distribution transformer capacity owned by utility

The source data is retrieved from Ergon Energy's corporate database (Ellipse).

DPA0502 - Distribution transformer capacity owned by High Voltage Customers

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

Distribution transformer capacity owned by High Voltage Customers

Data is the maximum of:

- last year’s data
- actual demand this last year
- authorised demand for a connection.

Data from last year is from last year’s RIN data.

Data for actual demand is the maximum demand billed in Ergon Energy’s billing system PEACE during the year for each connection. Data is from monthly SOC PEACE billing reports.

Authorised demand is recorded from our Tariff files, which are updated from Connection agreements as required.

Connections that have been de-energised during a period are deleted from file.

DPA0503 - Cold spare capacity included in DPA0501

The source data is retrieved via Inventory Records from Stock on Hand reports distinguishing both Owned Stock and Refurbished Owned Stock.

Zone Substation Transformer Capacity

DPA0601, DPA0602 and DPA0603

2020-21 totals are based on current corporate data extracted from SIFT, and/or Ergon Energy's North/South Transformer Cyclic Ratings records as a snapshot of the system at the end of the 2020-21 regulatory year. Checks of the established transformer tiers via technical diagrams (i.e. EDMS – Electronic Design Management System) and SCADA systems (i.e. ThinClient).

DPA0604 - Total zone substation transformer capacity

2020-21 totals are dependent upon RIN items DPA0601, DPA0602, DPA0603, and DPA0605 which are procured from SIFT and Inventory Records from Stock on Hand (SoH).

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

The source data is retrieved via SIFT substation records for the relevant financial year and Inventory Record Systems from Stock on Hand distinguishing both Owned Stock and Refurbished Owned Stock as of the first day of day of July 2021.

Distribution other - transformer capacity owned by utility

There are no items or records that identify as 'other transformer capacity' as owned by the utility.

Methodology

Distribution Transformer Total Installed Capacity

DPA0501 - Distribution transformer capacity owned by utility

The source data is retrieved via Corporate Database systems (Ellipse) and Inventory Stores record systems (Stock on Hand - SoH), filtered and summated by identifying in-service distribution transformers plus those assets deemed to be Cold Spare (i.e. DPA0503) as per below:

DPA0501 = Distribution Transformers (In-Service) + DPA0503 (Cold Spare Capacity)

DPA0502 - Distribution transformer capacity owned by High Voltage Customers

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.

Distribution transformer capacity owned by High Voltage Customers

The following approach was applied to calculating Distribution Transformer Capacity owned by High Voltage Customers (DPA0502):

- As the transformer capacity owned by customers at high voltage was largely not available, the calculation was based on the recorded annual peak demands; with each customers capacity estimated to be the standard transformer capacity greater than their historical peak demands.
- Where capacities were available these values were used.

DPA0503 - Cold spare capacity included in DPA0501

The source data is retrieved via inventory records from Stock on Hand distinguishing both Owned Stock and Refurbished Owned Stock. Values provided are based upon stock on hand values that are in Inventory as of the first day of day of July 2021. These items may or may not have been purchased for a specific project, these also include those deemed as a Critical Spare; Strategic Spare or Project Spare for a particular location/substation but have yet to be issued out of Inventory. All items sitting within Inventory that have not been issued a work order are counted.

DPA0503 = SoH(Owned Stock) + SoH(Refurbished Owned Stock)

Zone Substation Transformer Capacity

DPA0601, DPA0602 and DPA0603

2020-21 totals are based on current corporate data extracted from Ellipse as a snapshot of the system at the end of the 2020-21 regulatory year via SIFT and Ergon Energy’s North/South Transformer Cyclic Ratings records with zone substation transformer placement defined in Ergon Energy’s network architecture checked against technical diagrams (EDMS) and SCADA systems (ThinClient). Summation transformer capacities is undertaken for each RIN item (i.e. each transformer step tier).

DPA0604 - Total zone substation transformer capacity

Derived from the following RIN items:

DPA0604 = DPA0601 + DPA0602 + DPA0603 + DPA0605

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

The source data is retrieved via SIFT substation records for the relevant financial year and inventory records from Stock on Hand distinguishing both Owned Stock and Refurbished Owned Stock. Values provided are based upon Stock on Hand values that are in Inventory as of the first day of day of July 2021. These items may or may not have been purchased for a specific project, these also include those deemed as a Critical Spare; Strategic Spare or Project Spare for a particular location/substation but have yet to be issued out of Inventory. All items sitting within Inventory that have not been issued a work order are counted.

DPA0605 = SoH(Owned Stock - Zone Substation Transformers) + SoH(Refurbished Owned Stock-Zone Substation Transformers) + Zone Substation Standby Transformers

Distribution other - transformer capacity owned by utility

There are no items or records that identify other transformer capacity items owned by the utility.

Assumptions

Distribution Transformer Total Installed Capacity

Assets considered in this class (i.e. distribution transformers) are:

- Owned by Ergon Energy
- Identified in corporate records (i.e. Ellipse or Inventory Systems) as a distribution transformer with low voltage capacity (i.e. secondary voltage <1000V)
- Have the status of either in-service or deemed to be cold-spare. In other words, assets operational within the network (i.e. in-service) or are counted as 'spare', 'received', or 'under repair' in accordance with inventory records (i.e. cold-spare)
- Also established within Ergon Energy's Regulatory Network (for assets in-service). In other words, assets that are not a part of isolated systems.

Distribution transformer capacity owned by High Voltage Customers

The following assumptions and limitations apply to Distribution Transformer Capacity owned by High Voltage Customers (DPA0502):

- Transformer capacity for each high voltage customer is estimated from their individual annual peak demands recorded between 2006 and 2020.

Zone Substation Transformer Capacity

- All capacity assessments of transformers are procured from their individual HRT (Heat Run Test) rating in MVA. Where there is no HRT rating record available the transformer nameplate rating is utilised.
- All capacity assessments and step transformations and assignments are normally assessed based upon transformers established within the target substation site. Exceptions are made between substation sites for multi-step transformations (i.e. DPA0601 & DPA0602) where the initial step transformer does not supply directly to customers or an additional 2nd step transformer(s) onsite, but rather are dedicated to supply downstream zone substation(s). In addition, for tri-winded transformers, consideration of DPA0601 & DPA0602 are prioritised over assignment of DPA0603. In other words, DPA0601 cannot be attributed to a tri-winded transformer unless one winding is not utilised or two windings are of the distribution voltage

level - whist adhering to AER definitions (refer to 'Economic benchmarking RIN - For distribution network service providers - Instructions and Definitions').

- Capacity assessments take into account Regulated Ergon sites (Bulk & Zone Substation) with established transformers also owned by Ergon. Unregulated Ergon sites do not contribute to the capacity assessment.
- Capacity assessments include additional transformer installations from corporate records since the last update of transformer listings.
- Mobile generation units catering for zone substations are considered within the assessment as a snapshot of their operational status in June (e.g. Skids). Similarly, any zone substation transformers placed offline by mobile generation are included in the assessment as cold spares unless removed or decommissioned. Nomads are not included in the assessment and are deemed to be contingency assets.
- Zone substation capacity assessments ignore transformer capacities for transformations/steps beyond the distribution level or are established outside the boundaries of the substation (e.g. local transformer supply for substations, LV or downstream feeder SWER transformers).
- Capacity assessments ignore all substation measurement transformers not defined as a power transformer (e.g. current, voltage or earth transformers, etc).

Estimated Information

Distribution transformer capacity owned by High Voltage Customers

Estimated Information has been presented for Distribution Transformer Capacity owned by High Voltage Customers (DPA0502) in accordance with the Instruction at Table 3.5.2 Transformer Capacities Variables.

Ergon Energy believes the estimate supplied is its best estimate based on the available information at the time.

Explanatory Notes

Not applicable.

Table 3.5.3 - Public Lighting

Compliance with the RIN Requirements

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 5.3.

Table 5.3 Demonstration of Compliance

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 2020-21 regulatory year.

Sources

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

Methodology

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 (known as Rate 1, 2 & 4).

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 (known as Rate 3).

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

Assumptions

No assumptions were made.

Estimated Information

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

Explanatory Notes

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

BoP – 3.6 Quality of Services

Table 3.6.1 - Reliability

Compliance with the 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.

Sources

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

Methodology

Table 3.6.1 Reliability

For the regulatory (financial) year 2020-21, Major Event Day Threshold (tMed 7.54) was calculated utilising 5 years of Daily SAIDI sustained 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 (December 2018), 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 (1 July) and the number of customers at the end of the reporting period (30 June), rounded up to nearest whole number) 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 (> 3 min) 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, failure or request of that electrical installation which only affects supply to that customer is not deemed an interruption as defined in STPIS 2018

[Appendix A]. These following events have been confirmed through site inspection to have resulted from faults and failures within the customer's installation or request and as such are considered to be an event beyond the boundary of the DNSP's electricity supply network and therefore handles as an exclusion 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 <u>inclusive</u> of MEDs).

DQS0101 - Whole of network unplanned SAIDI

Relevant Financial Year (Between 1 July and 30 June).

Completed unplanned sustained (> 3 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 and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0102 - Whole of network unplanned SAIDI excluding excluded outages

Relevant Financial Year (Between 1 July and 30 June).

Completed unplanned sustained (> 3 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 (> 3 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 and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0104 - Whole of network unplanned SAIFI excluding excluded outages

Relevant Financial Year (Between 1 July and 30 June).

Completed unplanned sustained (> 3 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 (> 3 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 and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0106 - Whole of network unplanned SAIDI excluding excluded outages

Relevant Financial Year (Between 1 July and 30 June).

Completed unplanned sustained (> 3 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 (> 3 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 and Customer Installation Faults/Failures which reside beyond the electricity supply network.

DQS0108 - Whole of network unplanned SAIFI excluding excluded outages

Relevant Financial Year (Between 1 July and 30 June).

Completed unplanned sustained (> 3 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.

Assumptions

No assumptions were made.

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 (December 2018).

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

Compliance with the 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.

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.

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 (December 2018) 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 (1 July) and the number of customers at the end of the reporting period(30 June)) 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 (> 3 min) 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, failure or request of that electrical installation which only affects supply to that customer is not deemed an interruption as defined in STPIS 2018 [Appendix A]. These following events have been confirmed through site inspection to have resulted from faults and failures within the customer's installation or request and as such are considered to be an event beyond the boundary of the DNSP’s electricity supply network and therefore handles as an exclusion 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.

Assumptions

Refer to 7.12 Estimated Information.

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."

Ergon Energy believes the estimate supplied is its best estimate based on the available information at the time.

Explanatory Notes

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

Table 3.6.3 - System Losses

Compliance with the 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.

Sources

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.

Methodology

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

Total energy received equal ((DOPED0301 to DOPED0408) - DOPED01))/(DOPED0301 to DOPED040)

Note that not all categories from DOPED0301 to DOPED0408 will have values.

Assumptions

No assumptions were made.

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).

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 3.6.4 - Capacity Utilisation

Compliance with the 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.

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.

Sources

DQS04 - Overall 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' (i.e. EB RIN Template 3.4) and donors of the elements of Zone Substation Transformer Capacity (i.e. Section 3.5.2.2 of EB RIN Template 3.5).

Methodology

DQS04 - Overall 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}

Assumptions

No assumptions were made.

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).

Explanatory Notes

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

BoP – 3.7 Operating Environment

Table 3.7.1 - Density Factors

Compliance with the RIN Requirements

All mandatory data entry fields have been populated.

Sources

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

Methodology

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.
- "DOPED0102 - 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.
- "DOPED0103 - 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.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined terms).

Explanatory Notes

Not applicable.

Table 3.7.2 - Terrain Factors

Compliance with the RIN Requirements

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.

Sources

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

Methodology

Table 6.4: Methodology for RIN Table 3.7.2 Terrain Factors

Variable	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 (DOEF0202DOEF0203) 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	The total number of spans is calculated based on data sourced from the Progress vs Plan – Vegetation report for the respective financial year (B-WK-WK-0635 Progress vs Plan – Vegetation). This report sources data taken from the Ellipse database. DOEF0205 does not include service line spans.

Variable	Addressing Basis of Preparation Requirements
	Spans on multiple circuits are only counted once.
Average urban and CBD vegetation maintenance span cycle (DOEF0206) Average rural vegetation maintenance span cycle (DOEF0207)	The average maintenance span cycle was calculated based on data sourced from the Progress vs Plan – Vegetation report for the respective financial year (B-WK-WK-0635 Progress vs Plan – Vegetation). This report sources data taken from the Ellipse database. 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 of 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 equal to the average number of trees per span as each tree is considered a defect
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.

Variable	Addressing Basis of Preparation Requirements
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) and the NSW Rural Fire service (NSW RFS). Information is considered Actual.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined terms).

Explanatory Notes

Not applicable.

Table 3.7.3 - Service Area Factors

Compliance with the RIN Requirements

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
- a span shares multiple voltages, the length of the span is also considered only once
- underground cables and overhead lines are considered separately.

Sources

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

Methodology

For 2020-21, 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 2020-21 is considered actual in accordance with the AER's requirements.

Assumptions

No assumptions were made.

Estimated Information

Ergon Energy has provided 'Actual Information' (as per the AER's defined terms).

Explanatory Notes

Not applicable.