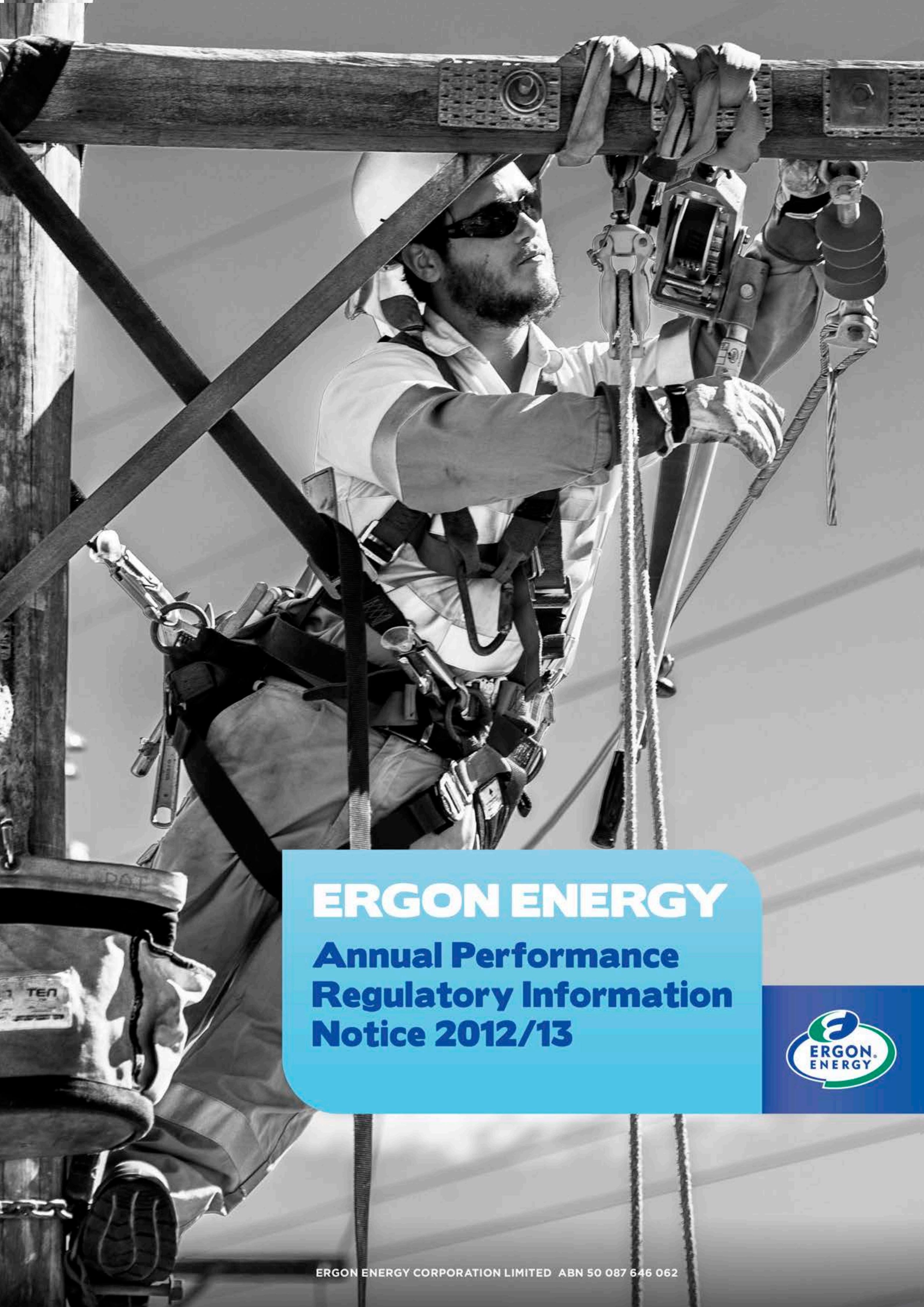

ERGON ENERGY

Annual Performance Regulatory Information Notice 2012/13

ERGON ENERGY CORPORATION LIMITED ABN 50 087 646 062

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CONTENTS

GLOSSARY

2011/12 APRIN	Ergon Energy 2011/12 Annual Performance Regulatory Information Notice
ABS	Australian Bureau of Statistics
ACCC	Australian Competition & Consumer Commission
ACS	Alternative Control Services
AER	Australian Energy Regulator
AER FDD	2010/15 Distribution Determination
CAC	Connection Asset Customers
CAM	AER approved Cost Allocation Method
Capex	Capital Expenditure
CBD	Central business district
CBRM	Condition Based Risk Management models
CICW	Customer Initiated Capital Works
CMS	Call Management System
CNOC	Communications Network Operations Centre
CPI	Consumer Price Index
DM	Demand Management
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme (AER)
DNSP	Distribution Network Service Provider
DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme (AER)
E&E	Efficiency & Effectiveness Program
EECL	Ergon Energy Corporation Limited
EEQ	Ergon Energy Queensland Proprietary Limited
EETL	Ergon Energy Telecommunications Pty Ltd
EG	Embedded Generator
ENCAP Review	Queensland Electricity Network Capital Program Review 2011
Ergon Energy	Ergon Energy Corporation Limited
Excel	Microsoft Excel
FACTS	Feedback and Claim Tracking System

FDRSTAT	FeederStat
FiT	Feed-in-tariff
GIS	Geographic information system
GSL	Guaranteed Service Level
GUI	Graphical User Interface
GWh	Gigawatt hour
HV	High Voltage
ICC	Individually Calculated Customer
IVR	Interactive Voice Recording
J-AMIT	Joint Asset Management Inspection Tool
KM	Kilometre
kV	Kilovolt
LR	Long Rural
LV	Low Voltage
MDA	Meter Data Agents
MDI	Maximum Demand Indicator
MED	Major Event Day
MSS	Minimum Service Standard
MVA	Megavolts-ampere
MVAR	Megavar reactive component of power
MW	Megawatt
NARMCOS (Data Model)	Network Assets Replacement Maintenance capex / opex Summary Model
NER	National Electricity Rules
NMI	National Metering Identifier
Nominal	With respect to dollars – means dollar of the day
Notice	Regulatory Information Notice
Opex	Operating Expenditure
POE	Probability of Exceedance
PTRM	Post Tax Revenue Model
QTC	Queensland Treasury Corporation
RAB	Regulated Asset Base

Real	With respect to dollars – means constant dollars at a specific date.
RIN	Regulatory Information Notice
ROAMES	Remote Observation Advanced Modelling Economic Simulation
Rules	National Electricity Rules
SAC	Standard Asset Customer
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCS	Standard Control Services
SFB	Service Fuse and Beyond
SMDB	Statistical Metering Database
SPARQ	SPARQ Solutions Pty Ltd
SR	Short Rural
STPIS	Service Target Performance Incentive Scheme (AER)
SWER	Single Wire Earth Return
TMED	Major Event Day Threshold
UbiNet	Ubiquitous Network
UR	Urban
VT	Voltage Transformer
W	Watt
WACC	Weighted Average Cost of Capital
YOM	Year of Manufacture
ZSS	Zone-Substation

1. INTRODUCTION

On 28 September 2012, the Australian Energy Regulator (AER) issued a Regulatory Information Notice (Notice) under Division 4 of Part 3 of the National Electricity (QLD) Law (NEL) to Ergon Energy Corporation Ltd (ABN 50 087 646 062) (Ergon Energy).

The Notice requires Ergon Energy to provide and to prepare and maintain the information in the manner and form specified in the Notice.

The AER requires the information for the performance or exercise of its functions or powers conferred on it under the NEL or the National Electricity Rules (NER), namely to:

- monitor the compliance of Ergon Energy with the 2010/15 Distribution Determination (AER FDD);
- publish reports relating to the financial or operational performance of Ergon Energy; and
- prepare for the making of future distribution determinations to apply to Ergon Energy.

Pursuant to sections 28F (1)(a) and 28M of the NEL, the Notice requires Ergon Energy to:

- provide in writing the information specified in Schedule 1 to the Notice;
- prepare and maintain the information in the manner and form specified in Schedule 2 to the Notice;
- verify, by way of a statutory declaration, the information specified in the Notice in accordance with Appendix D to the Notice;
- audit the information specified in accordance with Appendix E to the notice;

and deliver the said information electronically to AERInquiry@aer.gov.au, on or before 5:00 pm Australian Eastern Daylight Time on 13 December 2013 in respect of information for the 2012/13 regulatory year (1 July 2012 to 30 June 2013).

Accordingly, Ergon Energy is pleased to submit this **2012/13 Annual Performance Regulatory Information Notice,** as made by:

Ergon Energy Corporation Limited
PO Box 1090
Townsville Qld 4810

Enquiries or further communications should be directed to:

Jenny Doyle
Group Manager Regulatory Affairs
Ergon Energy Corporation Limited
Email: jenny.doyle@ergon.com.au
Phone: (07) 3851 6416
Mobile: 0427 156 897

2. CONFIDENTIAL INFORMATION

In issuing its Notice to Ergon Energy, the AER noted that it would treat information in accordance with the relevant provisions of the NEL, the NER and the AER's information policy[1] in relation to the use and disclosure of information provided.

Ergon Energy must do the following to make a confidentiality claim:

(a) for all information and documents, clearly identify and mark the part of the information that Ergon Energy considers confidential;

(b) provide reasons in sufficient detail to support each confidentiality claim focusing on the detriment that disclosing the information might cause Ergon Energy; and

(c) submit both a public and confidential version of the information.

A confidentiality claim, by itself, is insufficient to prevent disclosure. Both the NEL and the *Competition and Consumer Act 2010 (Cth)* provide for the AER to disclose confidential information in certain circumstances. In particular, section 28ZB of the NEL allows the AER to disclose information where:

(a) disclosure would not cause detriment to the information provider or the person from whom the information provider received the information; or

(b) the public benefit in disclosing the information outweighs that detriment.

Making a confidentiality claim in the manner mentioned above will reduce the chance that the AER will exercise these powers. Ergon Energy notes the AER would provide notice and an opportunity to comment prior to exercising these powers.

Ergon Energy notes that regard has been given to the AER's Better Regulation Reform Program – Confidentially Guidelines, November 2013 in assessing confidentiality claims in the 2012/13 Annual Performance Regulatory Information Notice (2012/13 AP RIN). Of note, on 21 October 2013 the AER requested Ergon Energy to contact its independent auditors (Parsons Brinkerhoff, and the Queensland Audit Office) to advise of the AER's intention to disclose audit reports issued to Ergon Energy in respect of the 2012/13 AP RIN, subject to any confidentiality claims made. Confirmation was obtained on the 3rd and 4th October 2013 respectively, from both auditors agreeing to the release of their audit reports / audit opinion.

Ergon Energy has made no claims for confidentiality in the 2012/13 AP RIN.

[1] *ACCC–AER information policy: the collection, use and disclosure of information*, 23 October 2008, available at www.aer.gov.au

3. ANNUAL PERFORMANCE RIN WORKBOOKS

RIN - Schedule 1 paragraph 1.1 (a)-(b), Schedule 2 paragraph 1.1(a)-(d) and Appendix B and C (templates)

REQUIREMENT

Schedule 1, paragraph 1.1 (a) of the Notice requires Ergon Energy to provide all information required in the Regulatory Accounting Statements, being the information required in the Excel workbook attached as Appendix B to the Notice. Furthermore, Schedule 1 paragraph 1.1(b) requires the provision of the information required in the Non-Financial Regulatory Templates in the Excel workbook attached at Appendix C to the Notice.

The AER requires Ergon Energy to verify information specified in Appendix E to the Notice, as provided in the Regulatory Accounting Statements and Non-Financial Regulatory Templates by way of an Audit in accordance with that Appendix E.

The AER also requires Ergon Energy to verify specified information, by way of a statutory declaration in accordance with Appendix D to the Notice.

Finally, in accordance with Schedule 1 paragraph 12.1 the AER requires Ergon Energy to provide an extract from the Ergon Energy Board minutes, or a resolution of the Board, that confirms specified information provided in the Regulatory Accounting Statements and the Non-Financial Regulatory Templates is true and fair.

ERGON ENERGY 2012/13 ANNUAL PERFORMANCE RIN WORKBOOKS

Ergon Energy's completed 2012/13 Annual Performance RIN Workbooks (2012/13 APRIN Workbooks), being the Microsoft Excel workbooks at Appendix B and Appendix C to the Notice, are provided as attachments to Ergon Energy's 2012/13 AP RIN - Regulatory Accounting Statements **[EE_1213APRIN_001]** and Non-Financial Regulatory Templates **[EE_1213APRIN_002].**

Of note, Ergon Energy made the following minor amendments to tables within templates, as detailed in Table 3-1 and 3-2 below. Importantly, these changes have either been agreed with the AER or don't' alter the requirements of the RIN; rather they provide for improved disclosure or alternatively, amend perceived errors in drafting of table headings.

Table 3-1: Appendix B – Regulatory Accounting Statements (Minor Amendments to Templates)

RIN Template	RIN Template Reference	Amendment
All templates	Inconsistencies in the number of decimal places displayed throughout worksheets, from 1 decimal point to the nearest thousand dollars	Have displayed all templates rounded to the nearest thousand dollars
Template 7 Capital expenditure for Tax Depreciation	Table 1: Tax Standard Live and Capital expenditure Additions – Standard control services (SCS)	Heading was amended to change Live to Lives (plural)

RIN Template	RIN Template Reference	Amendment
Template 5 Capital expenditure	Table 2: ACS Table 3: Other services	Table numbers for Table 2: ACS and Table 3: Other services were renamed to Table 4 and Table 5 respectively, to maintain sequential numbering within Template 5.
Template 9 Network Maintenance Overheads	Table 1 Network Maintenance Overheads by Category	Changed formatting in cells I12:I16 from 'amount' to 'percentage' as formulas calculate the percentage change between actual and forecast, yet cells are formatted by amount.
Template 10 Network operating costs (including overheads)	Table 6: Non–network alternatives (demand management) operating costs that are not captured by the Demand Management Incentive Scheme (DMIS) ($ nominal)	Total cells at G101-J101 were issued with a hard coded number – 0 (zero), Ergon Energy has deleted the zero's and inserted a formula to sum the impact for all projects.
Template 12 Cost Categories	Table 1: Operating and maintenance costs by category	Formulas in cells F12-F14, I12-I14, L12-L14, and O12-O14 calculate the percentage change between actual and forecast yet cells are formatted by amount. Formatting has been changed to display the result as a percentage.

Table 3-2: Appendix C – Non Financial Regulatory Templates (Minor Amendments to Templates)

RIN Template	RIN Template Reference	Amendment
Template 1d STPIS MED Threshold	Table 1: MED threshold Alpha - average of Ln(SAIDI)	Error identified in the Alpha - average of Ln(SAIDI) formula as it incorrectly omits cell E1846 (30 June 2013) in the 5 year range of data. Ergon Energy has amended the formula from AVERAGE(E20:E1845) to AVERAGE(E20:E1846) to reflect the complete data range.
Template 1d STPIS MED Threshold	Beta-standard deviation of Ln(SAIDI)	Error identified in the Beta-standard deviation of Ln(SAIDI) formula as it incorrectly omits cell E1846 (30 June 2013) in the range, the impact is the exclusion of one day (30 June 2013) in the 5 year range of data. In addition, as confirmed by the AER via email on the 22 August 2013, the Excel function has been changed from STDEV to STDEVP to reflect the calculation of the Major Event Day (MED) threshold based on 5 years of daily System Average Interruption Duration Index (SAIDI) data input, rather than only a sample within the population. Accordingly, Ergon Energy has amended the formula from STDEV(E20:E1845) to STDEVP(E20:E1846).
Template 3 Outcomes Customer Service	Table 3: Customer service Customer complaints (number) Complaint - technical quality of	Overridden formula in cell H65 - Table 3: Customer service which was linking to cell H27 - Table 2: Complaints - technical quality of supply, due to

RIN Template	RIN Template Reference	Amendment
	supply	unavailability of data which meets the complaints definition in the RIN. Also refer to the assumptions and methodologies for Template 3 at Table 4-53 to 4-55.
Template 4 General Information	Table 1: Metered Supply Points	An additional row has been inserted into this table to incorporate the category, transmission, to reflect the entire data set for metered supply points. Consequently, the formulas for the total metered supply points have been updated to incorporate the additional row.
Template 4 General Information	Table 2: Energy Delivered	An additional row has been inserted into this table to incorporate the category, transmission, into the energy delivered data set for completeness. Consequently, the formulas for the total energy delivery have been updated to incorporate the additional row.
Template 4 General Information	Table 3: Line length	An additional row has been inserted into this table to incorporate the category, Transmission, into the line length count. Consequently, the total formula's has been amended to incorporate the additional row. In addition, the total km formulas for all categories have also been amended to incorporate underground lines (column D – F) into the count.
Template 4 General Information	Table 6: Unmetered Supply Points	An additional row has been inserted into this table to incorporate the category, Transmission, for consistency with Table 1 and Table 3 of Template 4 General Information.
Template 5b Network data - Feeder Reliability	Table 1: Annual Feeder Reliability Data Maximum demand (MW)	As confirmed with the AER via email on the 3 September 2013, the measure (MW) in the heading for Maximum Demand (cell H9) has been amended to MVA. This aligns with the STPIS (and QLD Electricity Industry Code) definitions for Feeder Categories which require the assignment of categories to be based on feeder maximum demand (per km) expressed in MVA (not MW).
Template 5c Network Data Outages	Table 1: Causes of unplanned sustained outages	As confirmed with the AER via email on the 22 August 2012, the formula in Template 5c (Rows 10 to 19, Col C) is resulting in an overstatement of total outages, with a simple sum counting multiple rows (in Template 5a) against one outage (in Template 5c). As the AER advised the potential overstatement of outages will be taken into account when using the cause of outage data, no changes have been made by Ergon Energy to the formula in this template.

RIN Template	RIN Template Reference	Amendment
Template 5d Outcomes Planned Outages	Table 1: Planned outages	As advised by the AER via email on 22 August 2013, Ergon Energy has amended Template 5d to report planned SAIDI and System Average Interruption Frequency Index (SAIFI) in total. The current row headings (after removing excluded events) are not meaningful for planned outages and have been deleted from the template.

4. ASSUMPTIONS AND METHODOLOGIES

RIN - Schedule 1 paragraph 1.1 (c)(i)-(ii)

REQUIREMENT

Schedule 1 paragraph 1.1 (c) requires explanation relative to the 2012/13 AP RIN Workbooks, being the Microsoft Excel workbooks at Appendix B and Appendix C of the Notice, where applicable, of:

(i) the assumptions and methodologies underlying the information provided; and

(ii) each instance where the information cannot be provided or is not provided in full.

The AER requires Ergon Energy to verify this information, by way of a statutory declaration in accordance with Appendix D to the Notice.

ASSUMPTIONS & METHODOLOGIES APPLIED BY ERGON ENERGY

Ergon Energy provides the below assumptions and methodologies as applicable to the information provided in the attached 2012/13 AP RIN Workbooks, the Regulatory Accounting Statements **[EE_1213APRIN_001]** and Non-Financial Regulatory Templates **[EE_1213APRIN_002]**. Instances where information required cannot be provided, or is incomplete, are noted throughout with reasons.

General Comments

Ellipse was commissioned on 4 September 2006 as the Management and Financial reporting tool. The chart of accounts structure includes a district code and four segments forming an account line of four alphabetic and seventeen numeric characters.

- District: Separate legal entities of Ergon Energy consisting of parent entity and subsidiaries;
- Responsibility Centre: Business unit groups responsible for revenues, expenses for a function/ location;
- Activity: Type of work being undertaken. Also used for balance sheet classification: asset, liability, equity and Work in Progress (WIP);
- Product: Product or service being provided, for example High Load Escort; and
- Element: the nature of the revenue received or expense incurred.

Each revenue, cost element, asset and liability that when combined constitute the sum of Ergon Energy activities, and any associated adjustment to these, must have its origin in an audited Statutory Accounts.

Regulatory Accounting Statements

Template 1 – Income Statement

Template 1 requires Ergon Energy to report the Income Statement (Table 1). Ergon Energy understands that the information gathered will be used by the AER to monitor revenues for each service classification. Elements of the information are used to calculate financial ratios, used for intra and inter-business comparison and the AER will also monitor and report on information such as divided payments, tax payments, depreciation and profit.

Ergon Energy makes the following comments with regard to the compilation of the Income Statement template.

Table 4-1: Template 1 - Income Statement

Items	Underlying assumptions and methodology
Distribution revenue	Revenue is measured at the fair value of the consideration received or receivable. As a network service provider, Ergon Energy receives Distribution Use of System (DUOS) income. All values have been extracted from Ellipse. Within the audited statutory accounts column the revenue recognised is inclusive of revenue from regulated and unregulated assets. The adjustments column consists of: ▪ Transmission Use of System (TUOS) revenue, which is reported in the Income Statement Category, TUOS; ▪ Unregulated revenue (identified by the activity segment of the chart of accounts); and ▪ Under / over recovery of income consistent with the adjustment for under / over recovery adjustments. The value of SCS distribution revenue was extracted from Ergon Energy's billing records. The Alternative Control Service (ACS)_ revenue is obtained from an activity code in the general ledger and is reconciled to data files used for pricing purposes
TUOS Revenue	The value of SCS TUOS revenue was extracted from the Ergon Energy billing records.
Cross Boundary Revenue	DUOS & TUOS revenue charged to Essential Energy for 33kV and 66kV lines, based on metered data for 2012/13.
Gain on disposal of fixed assets	The disposal of an item of Property, Plant & Equipment (PP&E) may occur in a variety of ways (e.g. by sale or scrapping at the end of its useful life). Ergon Energy's Asset Management Policy and Strategies discusses when assets should be disposed i.e. after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Assets disposed of can be regulated or unregulated and can be readily identified as they are recorded in different categories within the fixed assets register that identify if the asset is SCS, ACS or unregulated based on the services they provide in accordance with the AER FDD and the NER. The figure reported in the statutory accounts is the amount of proceeds that exceeds the carrying amount of the item. The amount disclosed in the adjustments column relates to the sale of unregulated assets. The assets register reports upon asset disposal by detailed category and by a mapping exercise. These are converted into AER reporting categories.
Contributions	Under Ergon Energy's Capital Contribution Policy (covering both cash contributions and gifted assets) contributions are accounted for as revenue. This aligns with the transitional clause 11.16.10 of the NER which allows Ergon Energy to maintain its current approach for the treatment of capital contributions whereby the annual capital contributions are included in its Regulated Asset Base (RAB) and instead, a deduction is made from annual revenue caps in order to determine the Annual Revenue Requirement. Any difference between forecast and actual capital contributions is managed through the unders/overs process annually. Cash capital contributions are received from small customers for subdivisions and other small customer initiated capital works (CICW) and gifted assets relate to Urban subdivisions and

Items	Underlying assumptions and methodology
	Commercial and Industrial customers. Contributions for ACS are identifiable by a separate code within Ergon Energy's general ledger. The split between the service categories (columns) is the result of a pro-rata apportionment based upon the assets classes constructed by CICW. The adjustment between the Audited Statutory Accounts and the Regulated Distribution business relates to contributions received from unregulated sources, including the isolated networks.
Interest Income	Ergon Energy holds bank accounts which service all activities of the consolidated group. Therefore, the interest income received from underlying banks accounts relates to all services provided by the parent entity. As such an allocation basis using PP&E ratios has been applied to pro-rata interest income across Ergon Energy's classification of services. The values have been extracted from Ellipse and a manual calculation has been applied to report the disaggregation required. The adjustment column consists of interest income apportioned to unregulated services. In addition to the interest earned on its general purpose bank account, interest is also earned on loans to SPARQ and unwinding of discount on under recovery of regulated revenue. These two items are disclosed in the adjustments column.
Use of revenue cap assets for non-SCS purposes	Amount is calculated solely for regulated reporting purposes and hence the full number is shown as an adjustment. The adjustment is calculated by using data extracted from the general ledger, as well as a number of causal allocators (e.g. employee numbers) to arrive at the reported values.
Other Revenue	Other revenue relates to a variety of receipts, including meter removals, recoverable works, sale of inventory etc. These are categorised across service classifications according to their classification in the Ellipse general ledger. The value in the adjustments column is the revenue from unregulated activities.
TUOS Costs	TUOS expense was obtained from an examination of the charges levied upon Ergon Energy and those passed on to retailers.
Cross boundary charges	Ergon Energy notes that the definition for 'Cross Boundary Charges', is the cost of using another DNSP's distribution network therefore Ergon Energy has included costs of using Energex's distribution network and costs for use of Ergon Energy's unregulated 220kV network. This is because Ergon Energy is operating under a transitional rule which allows it to pass through charges it incurs for use of Ergon Energy's unregulated 220kV network as a Designated Pricing Proposal Charge or 'TUOS' charge (refer transitional rule 11.39 of the NER). The AER FDD also requires Ergon Energy to maintain a TUOS unders and overs account, and to submit a record of all transmission related payment (including any transitional charges under rule 11.39) to the AER as part of its Annual Pricing Proposal.
Maintenance	The Ergon Energy general ledger records maintenance costs in a series of codes that differentiate between SCS, ACS and unregulated based on the services they provide in accordance with the AER FDD and the NER. The identification of maintenance costs is performed by mapping these codes into their appropriate RIN reporting category.
Operating Expenses	The Ergon Energy general ledger records operating costs in a series of codes that differentiate between SCS, ACS and unregulated based on the services they provide in accordance with the AER FDD and the NER. The identification of maintenance costs is performed by mapping these codes into their appropriate RIN reporting category.

Items	Underlying assumptions and methodology
	In the annual statutory accounts the feed-in tariff and guaranteed service level payments are classified as negative revenue, in the RIN these amounts are included in the adjustments column as they are reported as operating costs. Also included in the adjustments column is an amount for over-absorbed overheads at year end. This adjustment is made to comply with the AER approved CAM.
Depreciation	The Statutory approach for calculating depreciation has been used on a straight line basis by reference to the useful life of each item of PP&E, other than freehold land and easements which are not depreciated. An assessment of useful lives is performed annually. All values have been extracted from Ellipse. The audited statutory accounts column includes depreciation and amortisation for the parent company EECL. It consists of amortisation of intangible assets such as computer software, licences and customer contracts and relationships, and depreciation for supply systems, power stations, buildings, and other plant and equipment, as well as impairment of non PP&E assets, i.e. Impairment of Doubtful Debts. The adjustments column relates to depreciation and amortisation of Ergon Energy's unregulated power station assets comprising of isolated generation and distribution systems, and other unregulated assets. The unregulated, isolated and ACS assets are identified by the use of different asset categories within the fixed assets register.
Finance Charges	Interest expense is the result of Ergon Energy's total borrowings which are used to fund its entire capital works program. Hence this amount has been apportioned across the reporting categories on the basis of the PP&E ratios. The adjustment column is therefore an estimate of the interest expense that relates to the funding of these unregulated assets.
Use of revenue cap assets for non-SCS purposes	This adjustment is to allow for the use of regulated assets for non-SCS purposes. The adjustment is calculated by using data extracted from the general ledger, as well as a number of causal allocators (e.g. employee numbers) to arrive at the reported values. This number is calculated solely for regulated reporting purposes.
Loss on disposal of fixed assets	The disposal of an item of PP&E may occur in a variety of ways (e.g. by sale or scrapping at the end of its useful life). Ergon Energy's Asset Management Policy and Strategies discusses when assets should be disposed i.e. after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Assets disposed of can be regulated or unregulated - these can be readily identified as SCS, ACS, unregulated or isolated based on the services they provide in accordance with the AER FDD and the NER as they are recorded in different categories within the fixed assets register. The figure reported in the statutory accounts is the proceeds minus the carrying amount of the item when the proceeds are the lesser amount.
Impairment Losses (nature of the impairment loss)	Nil to report
Other	The regulated component of these costs relates, in part, to Demand Management (DM) incentive arrangements and Guaranteed Service Levels (GSLs) which are separately identified in the Ellipse general ledger. The adjustment relates to unclassified costs of operating the isolated and unregulated assets.
Profit before tax	Revenue less expenses.

Items	Underlying assumptions and methodology
Income tax expense	Income tax expense is calculated as 30% of profit before tax, for each of SCS, ACS and unregulated based on the services they provide in accordance with the AER FDD and the NER. The adjustments relate to non-taxable revenue and an over – provision of tax in prior years.
Profit after tax	Revenue less expenses less tax.

Template 2 – Balance Sheet

Template 2 requires Ergon Energy to report the Balance Sheet Table 1. Ergon Energy understands that the information provided will be used by the AER to assess the base year costs, in particular, discrepancies between the balance sheet cash holdings and cash flows in the base year. Elements of the information will be used to calculate financial ratios (such as return on equity or liquidity ratios), used for intra- and inter-business purposes.

Ergon Energy makes the following comments in regards to the compilation of the Balance Sheet template.

Table 4-2: Template 2 – Balance Sheet: Current Assets

Items	Underlying assumptions and methodology
Cash and cash equivalents	Ergon Energy does not operate separate bank accounts for its different activities. An adjustment has been made to attribute a portion of Ergon Energy's cash balance to unregulated activities and each category of regulated services in accordance with PP&E ratios.
Trade and other receivables	The Ellipse general ledger records receivables in a number of categories. Where these are sufficiently specific to identify the amounts as being regulated or unregulated they are categorised accordingly. In other instances, such as Trade Debtors Control (which is used for both regulated and unregulated), the value of the receivables has been allocated in accordance with ratios calculated from PP&E balances. The adjustment in moving from the Statutory Accounts to Regulated business removes any unregulated component, such as a statutory accounting adjustment for under recovery of regulated revenue. The under / over recovery of revenue is an accounting adjustment, including the receivable for the Feed in Tariff (FiT) under the Solar Bonus Scheme which is written back through revenue.
Financial Assets	Nil to report
Derivatives	Nil to report
Current tax assets	The Ellipse general ledger clearly identifies Inter-Company tax receivable accounts for related entities. These accounts relate to the tax expense for those entities and are unregulated.
Prepayments	In the Ellipse general ledger, the type of prepayment is identified but not the applicable line of business. The value of prepayments has therefore been allocated in accordance with PP&E ratios.
Accrued Revenue	Accrued revenue is not identified by specific codes that signify whether it is SCS, ACS, isolated or unregulated based on the services they provide in accordance with the AER FDD and the NER. The value of accrued revenue has been allocated in accordance with PP&E ratios.

Items	Underlying assumptions and methodology
Investments	Nil to report. All investments are Non-Current.
Inventories	Inventories are used to support all aspects of the business and are not separately identified by line of business. The value of the inventories has been allocated in accordance with PP&E ratios.
Other	Residential tenancy bonds have been allocated in accordance with PP&E ratios.

Table 4-3: Template 2 – Balance Sheet: Non-Current Assets

Items	Underlying assumptions and methodology
Receivables	Receivables include loans to SPARQ, and statutory accounting adjustments for under recovery of revenue, FiT under the Solar Bonus Scheme, and the STPIS benefit. The under / over recovery of revenue is also an accounting adjustment, including the receivable for the Feed in Tariff (FiT) under the Solar Bonus Scheme which is written back through revenue.
Financial assets	Nil to report
Derivatives	Nil to report
Deferred tax asset	Nil to report
Investments	Ergon Energy has investments in a number of unregulated entities. These amounts are individually identified in the general ledger and are excluded from the regulated business by way of an adjustment.
Property, Plant and Equipment	A statutory accounting approach has been used for all data (including assets, disposals and depreciation). As such Ergon Energy has used the statutory opening balance for PP&E which differs to the opening RAB at Table 5.4 of the AER FDD. The recognition and measurement of PP&E is at fair value less any subsequent depreciation. Items included in this category are regulated electricity supply system and other regulated plant and equipment. Fair value is determined on the basis of an income approach using discounted future cash flow. Although capital contributions have been reported against asset categories in Template 5 – Table 7, there has been no adjustment to the closing PP&E balance for capital contributions. This reporting methodology aligns with the transitional rule to report capital contributions as revenue and prevents Ergon Energy reporting or recovering the value twice. The Audited Statutory Accounts column contains all PP&E for the parent entity EECL. This incorporates regulated and unregulated assets. The Ergon Energy Asset Register holds records of assets within asset categories that differentiate between isolated power station and other unregulated services, SCS and ACS based on the services they provide in accordance with the AER FDD and the NER. The adjustment shown in the Balance Sheet removes the value of unregulated assets and the value of the isolated power stations. Corporate assets (including buildings and motor vehicles) are used primarily to support regulated SCS and are allocated entirely to SCS in Template 2. A charge between lines of business is recorded in Template 1 to reflect compensation to the SCS line of business from each of the other lines of business for the use of these assets.
Other	Other includes inventories, intangible assets, and employee benefits. Inventories relate to Ergon Energy's sustainable poles project and accordingly have been classified as unregulated. Intangible assets include a regulated component for communication assets,

Items	Underlying assumptions and methodology
	and an unregulated component for ROAMES assets. Employee benefits are for the Super Surplus Defined Benefit.

Table 4-4: Template 2 – Balance Sheet: Current Liabilities

Items	Underlying assumptions and methodology
Trade and other creditors	Ergon Energy's trade and other creditors are of two main types: some are general across the entire business and others are specific to a particular activity. With those that are general they have been allocated in accordance with the PP&E ratios. Where the balance relates to a specific activity, the amount has been classified accordingly. The dividends payable to government are based on the profit for the year, and are therefore allocated on a Profit & Loss ratio.
Interest bearing borrowings	Interest bearing borrowings are for general business purposes and as such are allocated according to the ratios calculated from PP&E.
Customer deposits	Nil to report
Bank overdraft	Nil to report
Current tax liability	Nil to report
Provisions	Where a provision relates to a particular line of business it has been classified accordingly. Other provisions that relate to general activities have been allocated according to the PP&E ratios. Refer to Provisions template and Section 4. Template 14: Provisions in this report for more information.
Other	This category is mainly employee benefits and capital contributions, the remaining amounts are a variety of smaller items. The employee benefits are accrued to employees working across the entire business. Accordingly the ratios calculated from PP&E balances have been used. The capital contributions are mainly for the regulated business yet are reported by service category as required. The remaining amounts relate to lease incentives, scholarships and unclaimed monies and as such have been allocated by PP&E ratios.

Table 4-5: Template 2 – Balance Sheet: Non-Current Liabilities

Items	Underlying assumptions and methodology
Provisions	Where a provision relates to a particular line of business it has been classified accordingly. Other provisions that relate to general activities have been allocated using PP&E ratios. Refer to Provisions template and Section 4. Template 14: Provisions in this report for more information.
Interest bearing borrowings	Ergon Energy's borrowings are used to fund its entire capital works program and are not specifically identified by line of business. Therefore, an allocation has been made according to the PP&E ratios.
Retirement benefit obligations	Nil to report
Deferred tax liability	Deferred tax liabilities do not relate to any particular line of business and hence have been allocated according to the PP&E ratios.
Deposits	Nil to report

Items	Underlying assumptions and methodology
Other	This category includes employee benefits, and a lease incentive. The employee benefits and lease incentive have been allocated using PP&E ratios.

Table 4-6: Template 2 – Balance Sheet: Equity

Items	Underlying assumptions and methodology
Contributed Equity	The values shown for Contributed Equity are as per the general ledger. The opening balance is based on the priory year PP&E split, and the closing balance is based on the current year PP&E split.
Reserves	The values for Reserves are as per the general ledger. The fair value adjustment in the reserves is based on mapping the fixed asset register to the revaluation reserves.
Retained Profits	Retained profits include a Dividend Payable figure based on the profit and loss ratio adjustment, and Actuarial Gains/Losses that are based on the PP&E ratio. The remainder is the Profit/Loss and that is used as a balancing item.
Outside Equity Interest	Nil to report

Template 3 – Cashflow

Template 3 requires Ergon Energy to report the Cashflow Table 1. Ergon Energy understands that the information provided will be used by the AER as for base year costs, in particular discrepancies between the balance sheet cash holding and cash flow in the base year. Further, Cash flow statements may also be required to assess the financial performance of the business or its financial health to be able to meet its regulatory obligations.

It has been noted by the AER that balancing is required at the Distribution Business level. The opening balances should reconcile to the previous year's Balance Sheet. In addition, the cash flow amounts are intended to reconcile with the Balance Sheet totals.

Ergon Energy makes the following comments in regards to the compilation of the Cashflow Statement template.

Table 4-7: Template 3 - Cashflow Statement

Items	Underlying assumptions and methodology
Net Cash Flow for the Year	Calculated field being the movement between Net Cash Flow for the year and Cash balance at the end of the year.
Cash balance at the beginning of the Year	Sourced from 2011/12 APRIN Template 7b Statement of Financial Position - cash and cash equivalents.
Cash balance at the end of the Year	Sourced from Template 2 Balance Sheet - cash and cash equivalents.

Template 4 – Changes in Equity

Template 4 requires Ergon Energy to report Changes in Equity in Table 1. Ergon Energy understands that the information will allow opening and closing balances to reconcile back to the Balance Sheet, and provide transparency and accountability to stakeholders and associated reasons for differences between forecast and actual amounts (if published in performance reports by the AER).

It has been noted by the AER that balancing is required at the Distribution Business level and that the opening balances should agree to the prior year's regulatory accounting statement.

Ergon Energy makes the following comments in regards to the compilation of the Changes in Equity template.

Table 4-8: Template 4 - Changes in equity

Items	Underlying assumptions and methodology
	Contributed Equity
Opening Balance	This is the closing balances as shown in the 2011/12 APRIN.
Shares Issued	As the opening and closing balances are calculated using their respective years PP&E ratio this number reflects the difference that this creates.
Shares bought back	No shares were bought during the financial year.
Closing Balance	This is the closing balance of contributed equity split between reporting categories using the PP&E ratio.
	Reserves
Opening Balance	This is the closing balances as shown in the 2011/12 APRIN.
Fair value adjustments	This figure is derived from the Fixed Assets Register which records the revaluation reserve against individual assets. The fair value adjustment is the total amount held against distribution business assets.
Other	Nil to report
Closing Balance	This is the sum of the opening balance, fair value adjustments and other.
	Retained Profits
Opening Balance	This is the closing balances as shown in the 2011/12 APRIN.
Profit/(Loss) for period	This figure is obtained from the Income Statement.
Actuarial gains/(losses) on retirement obligations	This figure is used as a balancing item which is necessary due to the different methods of calculation used in preparing the statements.
Dividends Paid	Total dividends paid are as per the general ledger. The amount applicable to the Distribution Business is calculated using the PP&E ratio.
Closing Balance	The closing balance is as per the general ledger. The amount applicable to the Distribution Business is calculated using the PP&E ratio.

Template 5 – Capital expenditure (including overheads)

Template 5, Capital Expenditure requires Ergon Energy to provide detailed capital expenditure (Capex) information (including overheads), including SCS by reason; explanation of material differences in relation to SCS; Capex by asset class; ACS and other services spend. Other services are split into negotiated services and unregulated services. Template 5 also requires Ergon Energy to list related party transactions which are more than 5 per cent of the total SCS or ACS Capex. Further, capital contributions by asset class and disposals by asset class are required to be completed in this template.

The AER have stated that the information provided is necessary for the AER to monitor Capex and will be used to inform the assessment of Capex and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Ergon Energy makes the following general comments in respect of Capex.

Capex is recorded as either Direct Purchases, or Project costs.

Direct purchases relate to the purchase of a complete asset from an outside supplier such as motor vehicles or computers, whereas a construction asset (primarily its distribution assets) is treated as project costs. With constructed projects, one of two data sources is used depending upon whether the project is complete and capitalised into the fixed asset register or whether it remains incomplete.

Capex data is therefore drawn from three principle sources:

- Ergon Energy's general ledger;
- Ellipse Project Accounting module; and
- Microsoft Excel worksheet for categorisation of WIP construction assets based on Ellipse Estimating module data.

In all cases the total Capex is reconciled back to the totals contained in the general ledger.

Direct Purchases were extracted from a transactional level report direct from the general ledger which provides details about the asset purchased. This permits reporting in the appropriate asset category as required in the RIN Regulatory Accounting Statements.

Where the Project has been capitalised, Business Property Unit codes (BPU) are recorded against the Project to assign the asset category for capitalisation. Using an Access Database, a mapping process is undertaken to identify the AER asset category. This process also identifies unregulated Capex to be excluded.

Where the Project remains under construction and is yet to be capitalised, details are extracted from the Ellipse estimating module to ascertain the types of assets under construction. Once the information is extracted into Excel a mapping table is applied to covert the type of assets into the RIN asset categories.

More specifically, Ergon Energy makes the following comments regarding costs reported in the template tables:

- Actual Capital Contributions are not recorded against specific asset categories in the Ellipse general ledger. Therefore, an apportionment process has been applied to report against asset categories. This is based on the percentage split of asset categories for CICW expenditure from the Ellipse Project Accounting module.
- Within the Ergon Energy Ledger shared costs that have been charged via the overhead allocation process in accordance with the CAM are identified by an element code of 8100 within the chart of accounts hierarchy. The numbers shown in the template are a summary of these overhead costs by asset category.

Ergon Energy makes the following comments as relevant to the tables in Template 5.

Table 4-9: Template 5 - Capex – SCS by Reason

Items	Underlying assumptions and methodology
Forecasts	Ergon Energy has used the forecasts as amended by the Order of the Australian Competition Tribunal (ACT), and adjusted these amounts for actual consumer price index (CPI). The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the 2010/11, 2011/12 and 2012/13 regulatory years in the Post Tax Revenue Model (PTRM) used to derive the ACT's final merits review decision. The actual CPI entered into the PTRM for the respective year is based on the relevant March to March CPI weighted average of 8 capital cities result sourced from the Australian Bureau of Statistics (ABS) website (i.e. 3.33% for 2010/11, 1.58% for 2011/12 and 2.50% for 2012/13). In order to disaggregate the forecasts for Template 5, a separate Excel spread sheet was produced to recast the AER approved forecast capex and forecast capital contributions into the RIN formats and into $ 2012/13 terms. These figures were then reconciled against the forecast capex and forecast capital contribution figures derived at the macro level from the CPI adjusted PTRM noted above.
Asset replacement	Ergon Energy's capex is recorded in the general ledger against a series of codes that specify the nature of the capex cost. The identification of the amount to report as asset replacement involves summarising the amounts recoded against the appropriate code.
Corporate initiated augmentation	Ergon Energy's capex is recorded in the general ledger against a series of codes that specify the nature of the capex cost. The identification of the amount to report as corporate initiated augmentation involves summarizing the amounts recoded against the appropriate code.
CICW	Ergon Energy's capex is recorded in the general ledger against a series of codes that specify the reason for the capex. The identification of the amount to report as CICIW is simply a matter of summarising the amounts recoded against the appropriate code.
Reliability /quality improvement	Ergon Energy's capex is recorded in the general ledger against a series of codes that specify the nature of the capex cost. The identification of the amount to report as reliability/quality Improvement involves summarising the amounts recoded against the appropriate code.
Other	Ergon Energy's capex is recorded in the general ledger against a series of codes that specify the nature of the capex cost. The identification of the amount to report as other involves summarising the amounts recoded against the appropriate code.
Non-system assets	Non-System capex is identified through an analysis of the relevant general ledger codes.
Total distribution	Formula summing all distribution capex.

All material differences identified in Table 1 are to be explained in Table 2. Material differences are defined as the difference that is greater than 10% between AER approved forecasts (as per the AER FDD adjusted by CPI to the relevant regulatory year dollar value, or the ACT's orders), and Ergon Energy's reported actual amount.

On 13 October 2011, the Queensland Government announced the Electricity Network Capital Program (ENCAP) Review 2011. This independent Expert Panel reviewed the delivery of the capital program and provided advice to the government on the immediate and long-term savings, recommended changes and the benefits and risks of these changes in maintaining a secure, reliable and efficient network, with the final report provided in November 2011.

In early 2013 Ergon Energy commenced a further review as part of a Capital Reduction Strategy, which is continuing. To achieve this there is work underway to identify further projects that can be deferred using Non Network Alternatives, other risk mitigation methods, expected load growth forecasts and asset condition reports for the 2013/14 and 2014/15 financial years.

Table 4-10: Template 5 - Capex - Explanation of Material Differences

Items	Assumptions and methodology
System Assets	
Asset replacement	There was significant expenditure in defect replacements during the 2012/13 financial year. This was mainly driven by the cost of defects exceeding forecast. During the period July to December defects were cleared from the backlog of re-inspections as part of managing the aftermath of Cyclone Yasi (February 2011). Measures have been taken to reduce the cost per defect including management of: contract delivery resources; materials; and establishing a new outages and defect packaging methodology leveraging synergies in overall program delivery. In addition, criteria for classifying defects has been reassessed which has resulted in a reduction of the number of defects. Other actions taken to reduce costs include scope reductions to the Circuit Breaker Replacement program and by delaying a number of line refurbishment projects.
Corporate initiated augmentation	As a result of changes to design and security of supply criteria, and the use of improved load forecasting Ergon Energy has been able to reduce equipment rating uncertainty and as a consequence some projects were deferred. Ergon Energy also the deferral of the construction and redevelopment of some augmentation projects owing to the reduction in demand growth and as a result of alternative energy solutions. The purchase of Land and Easements also continues to be difficult, often taking longer than expected due to lengthy community consultation and regulatory requirements resulting in the delay of some projects.
CICW	An increased uptake of solar photovoltaic devices, suppressed demand for customer network connections, and mild weather conditions all affected load growth forecasts by further reducing the number of projects or deferring projects.
Reliability /quality improvement	N/A not material
Other	The Cyclone Area and Reliability Enhancement (CARE) program was limited to only active projects during the 2012/13 Financial Year. Also, no additional projects are scheduled to commence for the remainder of this regulatory control period. The UBINET project is also nearing completion where spend is tapering off reducing expenditure.
Non System Assets	N/A not material

Table 4-11: Template 5 - Capex - ACS

Items	Underlying assumptions and methodology
Street Lighting	Data for street lighting is extracted from the Ellipse system in the same manner described above under heading Template 5 – Capital expenditure (including overheads) with further filters applied to activity codes to obtain ACS (street lighting).
Fee based services	Capex is not incurred on Fee Based Services.

Items	Underlying assumptions and methodology
Quoted services	Ergon Energy's capex is directly attributed in the general ledger against a series of codes that specify the reason for the capex. The identification of the amount to report as Quoted Services involves summarising the amounts recoded against the appropriate code.

Table 4-12: Template 5 - Capex - Other services

Items	Underlying assumptions and methodology
Negotiated Services	Ergon Energy has no Negotiated Services.
Unregulated Services	Ergon Energy's capex is recorded in the general ledger against a series of codes that specify the nature of the capex cost. The identification of the amount to report as unregulated services involves summarising the amounts recoded against the appropriate code.

Items in the "Related Party Transactions" table, items which are more than 5% of the total SCS or ACS Capex respectively must be listed separately.

Table 4-13: Template 5 – Capex - Related party transactions

Items	Underlying assumptions and methodology
Related Party Transactions	The value of related party transactions is identified by billings issued by Ergon Energy Telecommunications Pty Ltd (EETL) and SPARQ Solutions Pty Ltd (SPARQ). The billings are allocated between (a) entities paid on behalf of; (b) Regulatory or Non-regulatory expenses; and (c) operating expenditure (opex) or capex expenses. Allocation between entities is established by budget allocation, while allocation between Regulatory and Non-regulatory is based on actual full year overhead allocation. Allocation between opex and capex for SPARQ billings is determined using the Ellipse general ledger percentage split between opex and capex expenditure. All EETL billings are classified as opex.

Table 4-14: Template 5 – Capex - Capital contributions by Asset Class

Items	Underlying assumptions and methodology
Capital Contributions	Actual Capital Contributions are not recorded against specific asset categories in the Ellipse general ledger. Therefore, an apportionment process has been applied to report against asset categories. This is based on the percentage split of asset categories for CICW expenditure from the Ellipse Project Accounting module. Within the Ergon Energy general ledger shared costs that have been charged via the overhead allocation process in accordance with the CAM are identified by an element code of 8100 within the chart of accounts hierarchy. The numbers shown in the template are a summary of these overhead costs by asset category.

Table 4-15: Template 5 – Capex - Disposals by Asset Class

Items	Underlying assumptions and methodology
Disposals by asset class	The Ergon Energy fixed assets register records and reports the value of asset disposals as well as any proceeds received. This reporting is by the asset categories used in the asset register, these are mapped to the AER reporting categories using the mapping table used for the preparation of other AER templates requiring a similar dissection.

Template 6 – Capex overheads

Template 6 requires Ergon Energy to report capex overheads. The AER have stated that the information provided is necessary for the AER in monitoring capex and will be used to inform the AER's assessment of capex and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

The information provided in Template 6 will have the same purpose as that of Template 5 (refer above). However, it can be noted that only overheads are to be reported in all tables completed in this template.

Further details on Assumptions and Methodologies as relevant to tables in Template 6 are detailed below.

Table 4-16: Template 6 - Capex overheads - SCS by reason

Items	Underlying assumptions and methodology
Forecasts	Ergon Energy has used the forecasts as amended by the ACT, and adjusted these amounts for actual CPI. The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the 2010/11, 2011/12 and 2012/13 regulatory years in the PTRM used to derive the ACT's final merits review decision. The actual CPI entered into the PTRM for the respective year is based on the relevant March to March CPI weighted average of 8 capital cities result sourced from the ABS website (i.e. 3.33% for 2010/11, 1.58% for 2011/12 and 2.50% for 2012/13). In order to disaggregate the forecasts for Template 6 – capex overheads, a separate Excel spreadsheet was produced to recast the AER approved forecast capex and forecast capital contributions into the RIN formats and into $2012/13 terms. These figures were then reconciled against the forecast capex and forecast capital contribution figures derived at the macro level from the CPI adjusted PTRM noted above.
Asset replacement	The Ergon Energy general ledger records capex against a series of codes that specify the nature of the capex cost. The identification of asset replacement involves extracting the totals for the codes that map to asset replacement.
Corporate initiated augmentation	The Ergon Energy general ledger records capex against a series of codes that specify the reason for the capex. The identification of corporate initiated augmentation involves extracting the totals for the codes that map to corporate initiated augmentation.
CICW	The Ergon Energy general ledger records capex against a series of codes that specify the nature of the capex cost. The identification of CICW involves extracting the totals for the codes that map to CICIW.

Items	Underlying assumptions and methodology
Reliability /quality improvement	The Ergon Energy general ledger records capex against a series of codes that specify the nature of the capex cost. The identification of reliability/quality improvement involves extracting the totals for the codes that map to reliability/quality improvement.
Other	The Ergon Energy general ledger records capex against a series of codes that specify the nature of the capex cost. The identification of other is simply a matter of extracting the totals for the codes that map to other.
Non-system assets	The Ergon Energy General Ledger records capex against a series of codes that specify the nature of the capex cost. The identification of non-system involves extracting the totals for the codes that map to non-system.
Total distribution	Total distribution capex is obtained through the addition of the above.

Table 4-17: Template 6 - Capex overheads - ACS

Items	Underlying assumptions and methodology
Street Lighting	The Ergon Energy general ledger records capex against a series of codes that specify the nature of the capex cost. The identification of street lighting involves extracting the totals for the codes that map to street lighting.
Fee based services	Ergon Energy does not incur capex on Fee Based Services.
Quoted services	The Ergon Energy general ledger records capex against a series of codes that specify the reason for the capex. The identification of Large Customer Connections is simply a matter of extracting the totals for the codes that map to Large Customer Connections.

Table 4-18: Template 6 - Capex overheads - Other

Items	**Underlying assumptions and methodology**
Negotiated services	Ergon Energy does not incur capex on Fee Based Services
Unregulated services	Overheads in the Ergon Energy general ledger are identified by a specific code. Reporting overheads involves identifying the amount against the appropriate code.

With regards to total Capex overheads attributable to Related Party, items that are more than 5 per cent of the total SCS or ACS Capex overheads, respectively are to be separately listed.

Table 4-19: Template 6 – Capex overheads - Total Capex overheads attributable to related party transactions

Items	Underlying assumptions and methodology
SPARQ	The only related party that contributes to Ergon Energy's overheads is SPARQ. The amount shown is calculated by taking total SPARQ total billings and deducting amounts that are allocated as per the CAM to other entities in the EECL Group. The proportion of SPARQ billings that relates to Ergon Energy's capital program are calculated on a pro-rata basis against actual capital and operating expenditure.

Template 7 – Capex for tax depreciation

Template 7 requires Ergon Energy to provide Tax Standard Lives and capex additions for SCS, split into system and non-system assets. Ergon Energy understands that the information provided will be used by the AER to allow the roll forward of the RAB.

Ergon Energy makes the following comments with regards to the Tax Standard Lives.

Table 4-20: Template 7 - Capex for tax depreciation - Tax Standard Live and Capex Additions - SCS

Items	Underlying assumptions and methodology
System Assets	The Ergon Energy Fixed Assets Register contains the capital value for all assets. It also contains standard lives which are adjusted in accordance with any revisions issued by the Australian Taxation Office. The AER asset reporting categories at times contain assets with differing lives, e.g. sub-transmission concrete poles have a different life to sub-transmission steel towers. In these instances a weighted average life, based upon the capital value was calculated and reported.
Non-System Assets	Non-system assets follow the same process as used for system assets.

Template 8 – Network Maintenance (including overheads)

Table 8 requires Ergon Energy to provide information on network maintenance by category; explanation of material differences under network maintenance; and other network maintenance costs. Ergon Energy understands that the information is necessary for the AER to monitor maintenance expenditure and will be used to inform the AER's assessment of maintenance expenditure and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Ergon Energy makes the following comments with regards to the respective tables completed in the Network Maintenance template. Of note, Network Maintenance is readily identified by activity codes within the general ledger coding structure. A mapping and summarisation process is used to convert the costs held against specific activity codes into the reporting categories.

Table 4-21: Template 8 – Network Maintenance - Network maintenance by category

Items	Underlying assumptions and methodology
Forecast	Ergon Energy has used the forecasts as amended by the ACT, and adjusted these amounts for actual CPI. The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the 2010/11, 2011/12 and 2012/13 regulatory years in the PTRM used to derive the ACT's final merits review decision. The actual CPI entered into the PTRM for the respective year is based on the relevant March to March CPI weighted average of 8 capital cities result sourced from the ABS website (i.e. 3.33% for 2010/11, 1.58% for 2011/12 and 2.50% for 2012/13). In order to disaggregate the forecasts for Template 8, a separate Excel spreadsheet was produced to recast the AER approved forecast Opex into the RIN formats and into $2012/13 terms. These figures were then reconciled against the forecast Opex figures derived at the macro level from the CPI adjusted PTRM noted above.
Preventive Maintenance	Comprises schedule inspection and maintenance activity. This work is carried out at predetermined intervals, or in accordance with prescribed intervals, or in accordance with

Items	Underlying assumptions and methodology
	prescribed criteria, in order to minimise the probability of network failure, minimise total life cycle costs, meet required operating conditions and performance standards, and keep Ergon Energy staff and the public safe. Work that is identified from this program can be undertaken as either asset renewal (defect manual) Capex or corrective maintenance, so that forced and corrective maintenance can be averted. The cost of preventative maintenance is identified by separate codes within the general ledger. Reporting is therefore a matter of extracting the total expenditure. The adjustment relates to the cost of preventative maintenance on Ergon Energy's isolated and unregulated assets. These costs are separately identified in the general ledger. The cost of preventative maintenance on ACS assets is also identified by an activity code within the general ledger coding structure.
Corrective Maintenance	Involves planned repair work identified and assessed as defects from preventative maintenance or customer reports in order to prevent an unplanned outage or dangerous electrical event. This category of work is planned and carried out regularly. The largest element of Ergon Energy's corrective maintenance program relates to vegetation management. The cost of corrective maintenance is identified by separate codes within the general ledger. Reporting involves extracting the total expenditure. The adjustment relates to the cost of corrective maintenance on Ergon Energy's isolated and unregulated assets. These costs are separately identified in the general ledger. The cost of corrective maintenance on ACS assets is also identified by an activity code within the general ledger coding structure.
Forced Maintenance	Involves unplanned repair, replacement or restoration work that is carried out as quickly as possible after the occurrence of an unexpected event or failure in order to bring the distribution network to at least its minimum acceptable and safe operating condition. Although it is unplanned, an annual provision is made for this category of expenditure. The cost of forced maintenance is identified by separate codes within the general ledger. Reporting involves extracting the total expenditure. The adjustment relates to the cost of forced maintenance on Ergon Energy's isolated and unregulated assets. These costs are separately identified in the general ledger. The cost of forced maintenance on ACS assets is also identified by an activity code within the general ledger coding structure.
Other network maintenance costs	Ergon Energy's maintenance costs are identified by specific codes within the General Ledger hence there are no amounts to be included in 'other'.

Of note, all material differences identified in the Network Maintenance by Category table (against forecast) are required to be explained. Material differences are defined as the difference that is greater than 10% between AER approved forecasts (as per the AER FDD adjusted by CPI to the relevant regulatory year dollar value, or the ACT's orders), and Ergon Energy's reported actual amount.

Table 4-22: Template 8 – Network Maintenance – Explanation of Material Differences

Items	Underlying assumptions and methodology
Preventive Maintenance	The $34m (-28%) underspend was primarily due to prudency and efficiency review of maintenance programs. Risk assessments for preventive maintenance programs were performed which resulted in changes to 26 of the 30 programs. Changes to improve efficiency were categorised as follows: ▪ Asset Criteria - Prioritising the assets selected for inclusion into programs; ▪ Inspection Cycle - alteration to inspection cycles; and ▪ Efficiency gains (small initially) due to new maintenance framework and electronic field data capture for substations.
Corrective Maintenance	The $14m (-12%) underspend was primarily due to the prudency and efficiency review of maintenance programs. Initiatives in vegetation management accounted for the bulk of the savings with a risk assessment approach to the access track program also contributing significantly. Increases in corrective lines maintenance have offset the reductions in preventive maintenance with some increase in reactionary work.
Forced Maintenance	The $25m (+57%) underspend was primarily due to: ▪ Exclusion of major event cost from forecasts; and ▪ Works associated with response to Cyclone Oswald which occurred in January 2013 - $12 million.
Other network maintenance costs	Nil to report

Items in the “Other Network Maintenance Costs” item of the Network Maintenance by Category table, that are more than 5% of the total SCS or ACS network maintenance costs, are required to be separately listed.

Table 4-23: Template 8 – Network Maintenance - Other network maintenance costs

Items	Underlying assumptions and methodology
Other network maintenance costs	All of Ergon Energy’s maintenance expenditure can be identified and reported against specific categories without having to use an “other” classification.

Related Party transactions, which are more than 5% of the total SCS or alternative control network maintenance costs, are required to be separately listed.

Table 4-24: Template 8 – Network Maintenance - Related party transactions

Items	Underlying assumptions and methodology
Related Party Transactions	These are identified using billing summaries provided by SPARQ and EETL. EETL provides telecommunications to the Ergon Energy Group; the total amount is therefore classified as an opex cost. The total billing is split between the entities in the Ergon Energy Group using the methodology specified in the CAM. The amount that relates to SCS is calculated on a pro-rata basis.

Template 9 – Network Maintenance overheads

Template 9 requires Ergon Energy to report maintenance overheads. The AER state that this information is necessary for the AER in monitoring maintenance overheads and will be used to inform the AER's assessment of maintenance overheads and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Ergon Energy understands that the information provided in Template 9 will have the same purpose as that of Template 8 (refer above). However, it can be noted that only overheads are to be reported in all tables in this template.

Ergon Energy makes the following comments in regards to the compilation of the Maintenance Overheads template.

Table 4-25: Template 9 - Maintenance overheads - Network maintenance overheads by category - Network maintenance (NM) overheads

Items	Underlying assumptions and methodology
Forecasts	Ergon Energy has used the forecasts as amended by the ACT, and adjusted these amounts for actual CPI. The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the 2010/11, 2011/12 and 2012/13 regulatory years in the PTRM used to derive the ACT's final merits review decision. The actual CPI entered into the PTRM for the respective year is based on the relevant March to March CPI weighted average of 8 capital cities result sourced from the ABS website (i.e. 3.33% for 2010/11, 1.58% for 2011/12 and 2.50% for 2012/13) In order to disaggregate the forecasts for Template 9, a separate Excel spreadsheet was produced to recast the AER approved forecast opex into the RIN formats and into $2012/13 terms. These figures were then reconciled against the forecast opex figures derived at the macro level from the CPI adjusted PTRM noted above.
Preventive Maintenance	All costs are directly attributed except for overheads which are allocated to specific maintenance jobs via the overhead process described in the CAM.
Corrective Maintenance	All costs are directly attributed except for overheads which are allocated to specific maintenance jobs via the overhead process described in the CAM.
Forced Maintenance	All costs are directly attributed except for overheads which are allocated to specific maintenance jobs via the overhead process described in the CAM.
Other network maintenance costs	All maintenance costs can be identified against one of the specified reporting categories, hence this category is Nil.

Items in the "Other Network Maintenance Costs" item of the Network Maintenance Overheads by Category table, that are more than 5% of the total SCS or ACS network maintenance overheads costs, are required to be separately listed.

In this regard, Ergon Energy has 'Nil' to report.

Template 10 – Network Operating costs (including overheads)

The AER have stated that the information provided is necessary for the monitoring of operating costs, and will be used to inform the AER's assessment of operating costs and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Template 10 requires Ergon Energy to provide information on network operating costs; and an explanation of material difference (10% variance between Forecast and Actual). In addition, Ergon Energy is also required to provide further dissemination of other operating costs; related party transactions; non-recurrent operating costs where items are greater than 5% of the SCS and ACS operating costs. Finally, information is required on other non-network alternatives not captured under the DMIS.

Ergon Energy makes the following comments in regards to the compilation of the Network Operating Costs template.

Table 4-26: Template 10 – Network Operating Expenditure - network operation costs

Items	Underlying assumptions and methodology
Forecasts	Ergon Energy has used the forecasts as amended by the ACT, and adjusted these amounts for actual CPI. The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the 2010/11, 2011/12 and 2012/13 regulatory years in the PTRM used to derive the ACT's final merits review decision. The actual CPI entered into the PTRM for the respective year is based on the relevant March to March CPI weighted average of 8 capital cities result sourced from the ABS website (i.e. 3.33% for 2010/11, 1.58% for 2011/12 and 2.50% for 2012/13).
Network operating costs	Network operating costs are separately identified in the Ellipse general ledger. Adjustments relate to amounts directly attributed to the isolated networks.
Meter reading	Costs incurred in Ergon Energy's capacity as a Metering Data Provider for Types 5, 6, and 7 metering installations and customer service activity. The cost of meter reading is identified by separate codes within the general ledger. Reporting requires extracting the total expenditure from designated codes. The adjustment relates to the cost of meter reading for customers on Ergon Energy's isolated and unregulated networks. These costs are separately identified in the general ledger.
Customer service (incl. Call Centre)	Customer Service relates to the cost of providing customer service to customers. Customer Service costs are separately identified in the general ledger. The adjustment relates to the cost of providing customer service to customers on Ergon Energy's isolated and unregulated networks.
Other operating costs	The regulated component of these costs relates, in part, to the DM incentive arrangements and GSLs which are separately identified in the Ellipse general ledger. The adjustment relates to unclassified costs of operating the isolated and unregulated assets.

Of note, all material differences identified in Table 1 are to be explained in Table 2. Material differences are defined as the difference that is greater than 10% between AER approved forecasts (as per 2010-15 Distribution Determination adjusted by CPI to the relevant regulatory year dollar value, or the ACT' orders), and Ergon Energy's reported actual amount.

Table 4-27: Template 10 – Network Operating costs - Explanation of material difference

Items	Underlying assumptions and methodology
Network operating costs	The $4m (+13%) overspend was primarily due to costs associated with the expansion of the Communications Network Operations Centre (CNOC). The growth in this area of operations exceeds that forecast at time of 2009 Regulatory Proposal and work is underway to limit impact.
Meter reading	N/A not material
Customer service (incl. Call Centre)	There was significant spend in Customer Installation Services covering customer-related activities that are ancillary to the provision of Ergon Energy's broader network, connection and metering services, including: cold water reports; check inspections; revenue protection; customer support; managing safety compliance; and customer advisory services. The actual costs exceeded forecast as a significant amount of budgeted spend was disallowed in the AER FDD and Merits review associated with this category, and driven by high demand for solar photovoltaic work.
Other operating costs	Primarily driven by the increase in FiT payments paid to customers on the Solar Bonus Scheme.

Items in the “Other Operating Costs” item of the Operating Costs table, that are more than 5% of the total SCS or ACS network operating costs, are required to be separately listed.

For greater transparency, Ergon Energy has disclosed most items in the Other Operating Costs item, in Table 3.

Table 4-28: Template 10 – Operating costs - Other operating costs

Items	Underlying assumptions and methodology
Other operating costs	Other operating costs are directly attributed and relate to GSLs and unclassified costs relating to the isolated and unregulated assets.

Related party transactions that are more than 5% of the total SCS or ACS network operating costs are required to be separately listed in table 4.

Table 4-29: Template 10 – Operating costs - Related party transactions

Items	Underlying assumptions and methodology
Related party transactions	These are identified using billing summaries provided by SPARQ and EETL. EETL provides telecommunications to the Ergon Energy Group; the total amount is therefore classified as an opex cost. The total billing is split between the entities in the Ergon Energy Group using the methodology specified in the CAM.

Non Recurrent network operating costs that are more than 5% of the total SCS or ACS network operating costs, are required to be identified in table 5.

Table 4-30: Template 10 – Operating costs - non-recurrent network operating costs

Items	Underlying assumptions and methodology
Redundancies	Redundancy payments increased following the public announcement in October 2012 that Ergon Energy would reduce its headcount by 500 as electricity consumption and peak demand are below levels of forecasts in the AER FDD. Therefore, capital and operational expenditure for the current regulatory control period have been significantly reduced. Demand for customer network connections is also expected to remain suppressed throughout the remainder of the current period to 2015. The amounts for redundancy costs have been obtained from the Ellipse Primary Cost report.
Cyclone Oswald	This year Ergon Energy faced the effects of Cyclone Oswald, which started out as a small, category-one cyclone on Cape York, but became a significant weather system that saw tens of thousands of Queenslanders grappling with the aftermath as it moved down the coast. The amount reported was obtained from Ellipse using the ECA900 report, for costs captured in work orders specific to Cyclone Oswald for the 2012/13 financial year.

Table 6 requires Non-Network alternatives operating costs that are not captured by the DMIS. Ergon Energy makes the following comments with respect to Template 10, Table 6.

Table 4-31: Template 10 - Non-network alternatives (demand management) operating costs that are not captured by the DMIS ($nominal)

Items	Underlying assumptions and methodology
Non-Network Alternatives	Non-Network Alternatives (NNA) are systems and processes implemented to reduce peak demand on the shared network. As such, all expenditure is related to SCS. NNA costs are separately identified in the general ledger. “Impact on demand (MW) current year” refers to new load brought under control, contracted to be interrupted or removed from network loads as a result of the project in the annual reporting period. This should change to MVA in future reporting periods. “Impact on demand (MW) project to date” refers to new load brought under control, contracted to be interrupted or removed from network loads as a result of the project since the project commenced. This should change to MVA in future reporting periods. "Deferred capital costs from DM project ($'000 nominal) Current Year impact" refers to the average annual deferral value expected to be delivered by the project on successful delivery of the NNA solution. "Deferred capital costs from DM project ($'000 nominal) Whole of Project Life Impact" refers to the total deferral value expected to be delivered by the project on successful delivery of the NNA solution.” "Operating costs from DM project ($'000 nominal) current year costs" refers to NNA Opex costs incurred by the project in the annual reporting period. "Operating costs from DM project ($'000 nominal) total project costs to date" refers to NNA Opex costs incurred by the project since the project commenced.

Template 11 – Network Operation overheads

Template 11 requires Ergon Energy to report overheads for network operating costs to further disseminate other network operating overhead costs where items are greater than 5% of total SCS and ACS.

The AER have stated this information is necessary for the AER and will be used to inform the AER's assessment of operating overheads and its underlying drivers at the next reset. It will be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

This template has the same purpose as Template 10 (above) however only overhead costs are recorded in this sheet.

Ergon Energy makes the following comments in regards to the compilation of the Network Operation Overheads template.

Table 4-32: Template 11 – Operating overheads - Overhead costs – network operations

Items	Underlying assumptions and methodology
Forecasts	Ergon Energy has used the forecasts as amended by the ACT, and adjusted these amounts for actual CPI. The adjusted amounts were calculated by allowing for a change between forecast and actual CPI for the 2010/11, 2011/12 and 2012/13 regulatory years in the PTRM used to derive the ACT's final merits review decision. The actual CPI entered into the PTRM for the respective year is based on the relevant March to March CPI weighted average of 8 capital cities result sourced from the ABS website (i.e. 3.33% for 2010/11, 1.58% for 2011/12 and 2.50% for 2012/13).
Network operating costs	Overheads are allocated to jobs in accordance with the process specified in the CAM. They are identified in the general ledger by a specific code which forms part of the larger code that specifies the type of operating cost.
Meter reading	Overheads are allocated to jobs in accordance with the process specified in the CAM. They are identified in the general ledger by a specific code which forms part of the larger code that specifies the type of operating cost.
Customer service (incl. Call Centre)	Overheads are allocated to jobs in accordance with the process specified in the CAM. They are identified in the general ledger by a specific code which forms part of the larger code that specifies the type of operating cost.
Other operating costs (itemise in table below)	Overheads are allocated to jobs in accordance with the process specified in the CAM. They are identified in the general ledger by a specific code which forms part of the larger code that specifies the type of operating cost.

Items in the "Other Operating Costs" item of the Network Operating Overheads table, that are more than 5% of the total SCS or ACS network operating overhead costs, are required to be separately listed.

Table 4-33: Template 11 – Operating overheads - Other network operating overhead costs

Items	Underlying assumptions and methodology
Other network operating costs	These are identified in the general ledger using the specific code that identifies a cost as being an overhead.

Template 12 – Costs by category – SCS

Template 12 requires Ergon Energy to provide operating and maintenance costs by category for SCS.

The AER have stated this information is necessary for the monitoring of expenditure by various components and categories, and will be used to inform the AER's assessment of expenditure and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

As clarified with the AER on 25 September 2013, this information has been provided inclusive of overheads.

Table 4-34: Template 12 – Costs by category - Operating and maintenance costs by category

Items	Underlying assumptions and methodology
Forecasts	Ergon Energy has applied the same methodology used in Templates 8-11 for forecasts and all data includes overheads as advised by the AER in a confirmation email received on the 25 September 2013.
Opex	Ergon Energy notes that opex is readily identified by activity codes within the general ledger coding structure. A mapping and summarisation process is used to convert the costs held against specific activity codes into the reporting categories.
Maintenance Expenditure	Ergon Energy notes that Maintenance expenditure is readily identified by activity codes within the general ledger coding structure. A mapping and summarisation process is used to convert the costs held against specific activity codes into the reporting categories.

Of note, all material differences identified in Table 1 are to be explained in Table 2. Material differences are defined as the difference that is greater than 10% between AER approved forecasts (as per the AER FDD adjusted by CPI to the relevant regulatory year dollar value, or the ACT's orders), and Ergon Energy's reported actual amount.

Table 4-35: Template 12 - Cost categories - Explanation of material difference by category

Items	Underlying assumptions and methodology
Opex	Increased labour costs due to an expansion in the Communications Network Operations Centre (CNOC) coverage, and an increase in Other costs due to an increase in overheads as the reduction in the capital works program shifted recovery of support costs into Opex.
Maintenance Expenditure	Materials increased due to additional forced maintenance due to the corrective work related to Cyclone Oswald. Decrease in contractor requirement due to deferment/cancelation of preventative maintenance activities which were predominantly contract resourced. Increase in other due to some costs miss-allocation (other that should have been contractor) and increase in overheads (to Opex) due to capital works program reduction which shifted recovery of support costs into Opex.

Template 13 – Step changes to Opex

Template 13 requires Ergon Energy to provide information on step changes to operating and maintenance costs if more than 5% of the total SCS or ACS network operating maintenance costs respectively.

Ergon Energy understands that the information will assist the AER in gaining a better understanding of how distribution businesses manage and report forecast and actual expenditures. The AER have also stated that the information will also be used for outcomes monitoring, performance reporting, benchmarking and to inform the AER for the next reset (including escalation rates).

Ergon Energy has 'Nil' Step Changes to Maintenance costs to report. Comments are made below, with regards to two identified Step Changes to Operating costs.

Table 4-36: Template 13 - Step changes to operating and maintenance costs

Items	Underlying assumptions and methodology
Operating Costs - Efficiency & Effectiveness Program	The E&E step change is derived from a number of sources, but is primarily an exercise of determining the cost savings generated by a number of initiatives which were quantified by comparing our forecast spend to our actual spend for the impacted activities / cost centres.
Operating Costs - Feed-in Tariff Solar Bonus Scheme	Information was sourced from the Ellipse General Ledger for the Solar Bonus FiT payments for 2012/13 and the comparative 2011/12 year. The amount presented as the step change is the difference between 2011/12 to 2012/13 costs.
Maintenance Costs	Nil to report

Template 14 – Provisions

Template 14 requires Ergon Energy to complete a table of provisions, detailing how each has been allocated to service segments, including explanations of the need for the provision, an explanation of the movements, and an explanation of any amounts reported under 'other adjustments' and the reasons for making the adjustments.

Ergon Energy understands that the AER will use information on provisions and changes in provisions to compare with information provided in the statements of financial performance and position, including the expected costs which provide for a better understanding of the financial position of Ergon Energy.

In regards to the underlying assumptions and methodologies for Provisions, Ergon Energy makes the following comments.

Table 4-37: Template 14 - Provisions

Item	Underlying assumptions and methodology
Restructuring	Apportioned to regulated / unregulated, and based on PP&E.
Competitive Neutrality	Fee charged to Ergon Energy under funding arrangements with QTC (refer response to weighted average cost of capital (WACC)) Apportioned to regulated / unregulated, and between service classifications based on asset base. The opening balance is on prior year PP&E basis. The adjustment is on the current year PP&E basis.
Employee benefit on-costs	Employee benefit on-cost provisions consist primarily of provisions for workers compensation and payroll tax on employee benefits. Apportioned to regulated / unregulated, and between service classifications based on asset base. The opening balance is on prior year PP&E basis. The adjustment is on the current year PP&E basis.
Rehabilitation	Split is made as per classification of individual sites, i.e. regulated sites and unregulated sites.

Item	Underlying assumptions and methodology
STPIS	Penalty is calculated on the regulated business' performance only.
Other	The system usage charge has been entirely treated as an adjustment as it relates to prior years. The NBN has been allocated on the PPE ratio. An additional minor amount has been included as an adjustment due to rounding's.

Ergon Energy notes that details relevant to provisions have been extracted from the Ellipse general ledger. Unless provisions are otherwise able to be directly associated with the service segment, an allocation has been based on the asset base. Further explanation of adjustments and the split between service segments is shown in the table below.

Table 4-38: Template 14 – Provisions - Other adjustments

Item	Underlying assumptions and methodology
Restructuring	Nil – other adjustments
System usage charge over recovery	Reconciling dollars to millions – this was the remainder when rounding was applied.
Competitive Neutrality	Details of provision used (Competitive Neutrality Fee (CNF) payment) and provision made.
Employee benefit on-costs	Nil – other adjustments
Rehabilitation	Indexation increase for owned properties charged to asset revaluation reserve which is neither opex nor capex.
STPIS	Nil –other adjustments
Other	Nil – other adjustments

Template 15 – Overheads allocation

Template 15 requires Ergon Energy to provide a description of each individual overhead and the amounts associated with each described overhead.

Ergon Energy understands that this information is required for auditing purposes. Where Ergon Energy's CAM does not always provide detail about how overheads/shared costs are allocated across the business, Ergon Energy understands that the AER will use this information to verify the application of the CAM by the DNSPs. Further the AER will use this information to inform benchmarking and comparative analysis between DNSPs.

In this regard, Ergon Energy applies a causal allocation basis for shared costs in accordance with Appendix D – Allocation of Corporate Support Costs of the CAM and in some instances using a commercial agreement between EECL and SPARQ.

Ergon Energy notes that the "Actual Budget Flow 12 mth (ECA966)" report is generated for Element Activity 8100 (Business Overhead) to provide the total shared cost allocation for the year. The opex and capex portions can be identified directly from their activity codes.

A mapping table is used to allocate each activity to a service category, i.e. an activity is classified as a SCS service, an ACS service or an unregulated service based on the services they provide in accordance with the AER FDD and the NER. The total shared cost allocation can now be split between SCS, ACS and unregulated services.

The total shared cost pool can be split between costs relating to the support services (those identified as per the CAM and costs for operations and asset management. Costs relating to the support services by business unit are identified from the Actual Budget Flow 12 mth (ECA966) report by business unit. Costs relating to operations and asset management have been apportioned as per their budgeted percentage split.

The total shared cost pool applicable to each business unit is now populated, along with the total applicable for each service category.

To allocate the total shared cost allocation for each business unit to each service category, the percentage of the shared cost allocation for the business unit is compared to the total shared cost pool. This percentage is then used to allocate the costs for each service category from each business unit.

Template 16 – Avoided cost payments

The AER has stated that this information is necessary for the monitoring of avoided cost payments, and will be used to inform the AER's assessment of expenditure and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Ergon Energy makes the following comments with respect to Avoided cost payments.

Table 4-39: Template 16 - Avoided cost payments

Item	Underlying assumptions and methodology
Avoided TUOS	The methodology used in calculating the avoided cost payments is described in Ergon Energy's Information Guide for SCS Pricing, 1 July 2013 to June 2014 (release 1.0, 7 June 2013). The payments are calculated by the Service Transaction Centre using the process which is described below: Clause 5.5(h) of the NER requires DNSPs to calculate "avoided charges for the locational component of prescribed TUOS services", and clause 5.5(i) requires DNSPs to calculate the amount to be passed through to an Embedded Generator (EG). This is done by: ▪ Determining the charges for the locational component of prescribed TUOS services that would have been payable by the DNSP for the relevant financial year "if the EG had not injected any energy at its connection point during that financial year"; and ▪ Determining "the amount by which the charges calculated in subparagraph (1) exceed the amount for the locational component of prescribed TUOS services actually payable by the DNSP, which amount will be the relevant amount for the purposes of paragraph (h) [clause 5.5(h)]". Avoided TUOS payments are made by Ergon Energy to EGs who have sought access to Ergon Energy's distribution network under clause 5.5 of the NER, who have a generator Connection Agreement with Ergon Energy that includes a relevant Avoided TUOS payment clause and who are registered as a Generator Rules Participant. Also refer to Attachment **[EE_1213APRIN_006]** for a further breakdown of DUOS and TUOS.
Other	Nil to report.

Template 17 – Alternative control and other services

Template 17 requires reporting of ACS & other services and is required for the AER in monitoring ACS & other services, and will be used to inform the AER's assessment of expenditure and its underlying drivers at the next reset. It will also be used to assist in any comparative analysis undertaken by the AER within the current and future regulatory control periods.

Ergon Energy makes the following comments with respect to ACS and other services.

Table 4-40: Template 17 - Alternative control and other services

Item	Underlying assumptions and methodology
ACS – fee based	ACS are directly attributed to specific general ledger product codes. Reporting is achieved by extracting from the general ledger the amounts against the relevant product codes. The split between directly attributed, overheads and revenue is performed by using codes specified in the general ledger established for that purpose.
ACS - quoted	ACS are directly attributed to specific general ledger product codes. Reporting is achieved by extracting from the general ledger the amounts against the relevant product codes. The split between directly attributed, overheads and revenue is performed by using the codes specified in the general ledger established for that purpose. Of note, the ACS Quoted Service category, 'Design and construct of new large customer connection assets' is misleading due to the inclusion of the term 'new' in the service category heading. Ergon Energy notes that this service can be applied to large customers requesting a new connection to the network or an upgrade to their existing connection. It would be more appropriate for the service category to be renamed as, 'Design and construct of large customer connection assets' in recognition that the costs may relate to new or augmented connection assets. In addition, Ergon Energy is unable to report ACS by the dissemination level requested (feeder level) as indicated during the consultation process on the 2012/15 RIN. The Ellipse system reporting for ACS is by category, not by category and feeder (urban (UR), short rural (SR), long rural (LR), isolated). There are a number of complexities in implementing system changes, which if implemented would only be valid for 2 years of this regulatory control period, as there are a number of uncertainties around the classification of services and pricing arrangements that may / may not apply to Ergon Energy's services from 2015. Data for ACS is captured in two systems, Ellipse and FACOM, of which the later interfaces into Ellipse. FACOM is in the process of being decommissioned and replaced with a new system, to progress any system changes at this point would not be considered prudent spend.
Other activities - unregulated	ACS are directly attributed to specific general ledger product codes. Reporting is achieved by extracting from the general ledger the amounts against the relevant product codes. The split between directly attributed, overheads and revenue is performed by using the codes specified in the general ledger.

Template 18 – EBSS

Template 18, Efficiency Benefit Sharing Scheme requires Ergon Energy to provide details of adjustments to controllable operating expenditure for the purposes of the operation of the AER's Electricity DNSPs, Efficiency Benefit Sharing Scheme (EBSS) (June 2008), as applicable to Ergon Energy for opex for the current regulatory control period.

Requirements note that only superannuation costs relating to defined benefit schemes are to be reported, and only self-insurance cost categories approved in the AER's determination are to be reported.

An explanation of changes to Capitalisation Policy is also required, including a description of any items that have previously been considered as opex items but are now considered capex items.

In this regard, Ergon Energy has 'Nil' Capitalisation Policy Changes to report in table 2.

In completing Template 18, opex for EBSS purposes (table 1), Ergon Energy makes the following comments.

Table 4-41: Template 18 - Opex for EBSS purposes

Item	Underlying assumptions and methodology
Debt raising costs	Reflect the amount presented in Template 18, Table 1. This has been sourced / calculated from QTC information.
Self-insurance and insurance costs	The amount disclosed as self-insurance and insurance costs consists of: ▪ the Self-insurance costs as per Template 21, Table 1 net of revenue received through external funding allocated in accordance with the CAM to derive the opex SCS related portion (Self-insurance is distributed via corporate overheads shared costs pool, ultimately allocated between opex/capex according to processes described in the CAM). An overhead allocation of 27.7% is used. ▪ Insurance costs are extracted from the ledger, Elements 5970-6000 (totalling $5,008,949), and allocated in accordance with Ergon Energy's approved CAM to derive the opex SCS related portion (Insurance costs are distributed via corporate overheads shared costs pool, ultimately allocated between opex/capex according to processes described in the CAM). Overhead allocation of 27.7% used (as per Self-Insurance).
Superannuation defined benefit costs	Relating to retirement scheme are extracted from the ledger, Element 6240 (totalling $8,746,000) adjusted by a labour oncost split to derive the opex related portion. (Superannuation defined benefits costs are distributed via the labour on-cost and corporate overhead shared costs, ultimately allocated between opex/capex according to processes described in the CAM). Labour oncost split of 26.37% used.
DM innovation allowance costs	As per Template 20, Table Other includes (1) Non-network alternatives costs sourced from the same source as Template 10, Table 6. (2) Pass Through Event costs represent the actual FiT operating costs reduced by the following; payments made to customers in isolated regions, incorrect payments to customers eligible for the 8c tariff yet incorrectly paid the 44c tariff, and the approved FiT forecast allowance. We note the FiT cost pass through application has been prepared on an accruals basis in accordance with Chapter 6 of the NER, clause 6.6.1(j)(2)

Template 19 – Jurisdictional scheme amounts

Template 19 requires Ergon Energy to complete the table for each approved Jurisdictional Scheme. Ergon Energy understands that Jurisdictional Scheme information is used by the AER to monitor approved Jurisdictional Schemes throughout the regulatory control period.

In completing Template 19, Jurisdictional Scheme amounts, Ergon Energy makes the following comments.

Table 4-42: Template 19 - Jurisdictional scheme amounts

Item	Underlying assumptions and methodology
Jurisdictional scheme amounts	Ergon Energy did not report any approved Jurisdictional Schemes as it is not yet operating under the jurisdictional scheme cost recovery provisions in Chapter 6 of the NER. Ergon Energy contacted the AER via email on the 26 September 2013 and confirmed the interpretation of this requirement is correct

Template 20 – Demand Management Incentive Scheme

Template 20, Demand Management Incentive Scheme requires Ergon Energy to provide all DM innovation allowance information for the relevant regulatory control period. Ergon Energy understands this information will form the basis of the AER's assessment of the DNSP's compliance with the DMIS, and its entitlement to recover expenditure under the DMIS. The AER also state the information will also assist in t assessing proposals for DM expenditure in Opex and Capex forecasts submitted in a DNSP's regulatory proposals, and in the development and implementation of the DMEGCIS (Demand Management and Embedded Generation connection incentive scheme), in future regulatory control periods.

In completing Table 20.1, demand management innovation allowance (DMIA) projects submitted for approval, expenditure under the DMIS, Ergon Energy makes the following comments.

Table 4-43: Template 20 - DMIA projects submitted for approval

Item	Underlying assumptions and methodology
DMIA projects submitted for approval	Operating costs represent those costs booked to activity code 55000 for the 2012/13 regulatory year as extracted from Ergon Energy's Ellipse financial reporting system. Activity code C2300 captures capex costs; however no capex costs were incurred during the 2012/13 regulatory year. . For further information, Ergon Energy refers the AER to the attached 2012/13 Demand Management Innovation Allowance - Annual Report to the AER, for the regulatory year ended 30 June 2013 **[EE_1213APRIN_007].**

Template 21 – Self-insurance

Template 21 Self-Insurance requires Ergon Energy to provide details of self-insurance events with an incurred cost of greater than $100,000 per event and self-insurance events with an incurred cost of less than $100,000.

Ergon Energy understands that information on actual, audited costs incurred by DNSPs on self-insurance events (collected annually) will assist the AER with determining an appropriate self-insurance allowance for DNSPs at the next regulatory reset.

The AER states the information is required to be reported annually so that DNSPs can clearly demonstrate (to the AER) that their business processes and reporting systems properly account for self-insurance events. This includes correctly accounting for the risks insured and costs to the DNSP.

For the purposes of completing Template 21, Self-Insurance event information has been sourced from the GSL and Claims group in Ergon Energy's Customer and Stakeholder Engagement business unit. Data was extracted from the Feedback and Claim Tracking System (FACTS), the claims database maintained by the group.

Table 4-44: Template 21 - Self-insurance events with an incurred cost of greater than $100 000 per event

Item	Underlying assumptions and methodology
Self-insurance events	A review of claims paid data for the period 1 July 2012 to 30 June 2013 revealed nil claims with an incurred cost greater than $100,000 per event and 958 claims with an incurred cost less than $100,000 and with an aggregate cost of $1,725,916. Ergon Energy's public liability policy has a per-claim (maintenance) deductible and an all claims (aggregate) deductible. Claims that have a cost less than the maintenance deductible are fully self-insured, meaning Ergon Energy incurs the total cost of the claim with no part of it paid by the insurer. Claims that have a cost that exceeds the maintenance deductible are also fully self-insured unless the total of the excess over the maintenance deductible of all claims is greater than the aggregate deductible. Once the aggregate deductible is exceeded, the insurer pays the cost of all claims net of the maintenance deductible which applies to each claim. The maintenance and aggregate deductibles applying on Ergon Energy's policy since 2010/11 are: ▪ 2010/11 Maintenance Deductible $250,000; Aggregate Deductible $1,000,000. ▪ 2011/12 Maintenance Deductible $250,000; Aggregate Deductible $1,000,000. ▪ 2012/13 Maintenance Deductible $250,000; Aggregate Deductible $1,000,000. Ergon Energy commented in the 2011/12 APRIN that there was an expectation that proceeds from 1 claim with an incurred cost greater than $100,000 per event would be received from the insurer during 2012/13. At the time of drafting the 2012/13 AP RIN, Ergon Energy had not yet received any proceeds in relation to the incident previously disclosed in the 2011/12 RIN.

Template 22 – Change of accounting policy (CHAP)

Template 22 requires Ergon Energy to provide information on the aggregate effect of the change in accounting policy on the balance sheet and income statements and the reason for the change in accounting policy. Ergon Energy understands that the information is required by the AER to assess forecast expenditure proposed by Ergon Energy's next reset. It captures changes in accounting policy made from year to year and the effect on the Financial Statements. The AER state this information will increase transparency and accountability to stakeholders.

Ergon Energy has no changes to accounting policies to report for the 2012/13 year, for the Balance Sheet and Income Statements.

Non-Financial Regulatory Templates

Template 1a – STPIS Reliability

Note: Templates 1a-e require Ergon Energy to enter STPIS information concerning customer service parameters set out in the AER's Electricity DNSPs, STPIS (November 2009), as applicable to Ergon Energy for the current regulatory control period. Reliability of supply, customer service, MED and unplanned outage performance, as well as exclusions are required to be reported in separate templates. Ergon Energy understands that this information is collected to inform the application of the STPIS to the DNSP in future regulatory control periods. The AER also state this information is also collected to monitor network performance, and may be used in performance reports. Template 1f in regards to STPIS-applied GSL performance is not required to be completed by Ergon Energy.

Template 1a requires Unplanned SAIDI and SAIFI (total, and total after removing excluded events), by each of Ergon Energy's feeder categories (UR, SR, LR) and also by Whole Network. Ergon Energy provides the following comments in this regard (as detailed in Table 4-48).

For ease of review, Ergon Energy has disaggregated comments on Template 1a (STPIS) Reliability by table, and by requirement within each table. Comments are therefore presented below, for each of SAIDI and SAIFI performance. The following general comments apply to all data presented in Template 1a.

Table 4-45: Template 1a - STPIS Reliability – Unplanned SAIDI/SAIFI

Item	Assumptions and methodology
Unplanned SAIDI / Unplanned SAIFI	All the reporting for the Reliability of Supply (RoS) component of STPIS are based on the network outage data retrieved from Feeder Stat (FDRSTAT) Oracle Database Tables recorded for the relevant regulatory year. Ergon Energy does not capture momentary interruption data, therefore it is not reported. Distribution Feeders are categorised as UR, SR or LR as per the definitions in Appendix A of the AER's Electricity DNSPs, STPIS (November 2009). Reporting is based on the feeder category that a feeder is considered to be at the end of the regulatory year as at 30 June. Exclusions are applied in accordance with clauses 3.3(a) & (b) (for RoS Reporting) of the AER's Electricity DNSPs, STPIS (November 2009). FDRSTAT has provision for different outage flags that are also applied to tag the outages for exclusions appropriately. Reliability of Supply reporting for SAIDI and SAIFI "Total": ▪ SAIDI and SAIFI for each feeder category calculated based on all Unplanned Normal and Service Fuse and Beyond (SFB) Completed Sustained Outages <u>including</u> all MEDs and non-MED exclusions for the relevant regulatory year. Reliability of Supply reporting for SAIDI and SAIFI "Total – after removing excluded events": ▪ SAIDI and SAIFI for each feeder category calculated based on all Unplanned Normal and SFB Sustained Outages <u>excluding</u> all MEDs and non-MED exclusions for the relevant regulatory year. For each feeder category, the End of Year unplanned SAIDI/SAIFI are calculated by dividing the total of unplanned customer minutes and customer interruptions (filtered as per below) for the regulatory year by the average of the numbers of customers on that feeder category at the beginning of the reporting period (1 July) and the number of customers at the end of the reporting period (30 June). For SAIDI/SAIFI for each feeder category "Total Unplanned" (refer above), the Sustained Outages Data must fit the following criteria: ▪ Outage Type = Unplanned or Forced; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1 July 2012 and 30 June 2013; ▪ Feeder Categorisation = [insert - feeder category]; ▪ Outage Maximum Duration is > 1 Min; ▪ INCLUDE Events = Normal; or Service Fuse or Beyond; or

Item	Assumptions and methodology
	Generation (Exemption clause: 3.3 (a) (2)); or Shared Transmission (Exemption clause: 3.3 (a) (5)); ▪ INCLUDE Exemptions = STPIS MED day; or Public Safety Isolation (Exemption clause: 3.3 (a) (7)). For SAIDI/ SAIFI for each feeder category "Total – after removing excluded events" (refer above), the Sustained Outages Data must fit the following criteria: ▪ Outage Type = Unplanned or Forced; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1 July 2012 and 30 June 2013; ▪ Feeder Categorisation = [insert - feeder category]; ▪ Outage Maximum Duration is > 1 Min; ▪ INCLUDE Events = Normal; or Service Fuse or Beyond; or ▪ EXCLUDE Events = Generation (Exemption clause: 3.3 (a) (2)); or Shared Transmission (Exemption clause: 3.3 (a) (5)); ▪ EXCLUDE Exemptions = STPIS MED day; or Public Safety Isolation (Exemption clause: 3.3 (a) (7)). For the whole of network, the End of Year unplanned SAIDI/SAIFI are calculated by dividing the total of unplanned customer minutes and customer interruptions (filtered as per below) on all UR, SR and LR feeder categories for the regulatory year by the average of the total numbers of customers on all three feeder categories at the beginning of the reporting period (1 July) and the total number of customers at the end of the reporting period (30 June). For SAIDI/SAIFI for Whole of network "Total" as explained above, the Sustained Outages Data must fit the following criteria to determine the WHOLE NETWORK SAIDI/SAIFI: ▪ Outage Type = Unplanned or Forced; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1 July 2012 and 30 June 2013; ▪ Feeder Categorisation = UR; or SR; or LR; ▪ Outage Maximum Duration is > 1 Min; ▪ INCLUDE Events = Normal; or Service Fuse or Beyond; or Generation (Exemption clause: 3.3 (a) (2)); or Shared Transmission (Exemption clause: 3.3 (a) (5)); ▪ INCLUDE Exemptions = STPIS MED day or Public Safety Isolation (Exemption clause: 3.3 (a) (7)). For SAIDI/SAIFI for Whole of network "Total – after removing excluded events" as explained above, the Sustained Outages Data must fit the following criteria to determine the WHOLE NETWORK SAIDI/SAIFI: ▪ Outage Type = Unplanned or Forced; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1st July 2012 and 30th June 2013; ▪ Feeder Categorisation = UR; or SR; or LR;

Item	Assumptions and methodology
	▪ Outage Maximum Duration is > 1 Min; ▪ INCLUDE Events = Normal; or Service Fuse or Beyond; EXCLUDE Events = Generation (Exemption clause: 3.3 (a) (2)) or Shared Transmission (Exemption clause: 3.3 (a) (5)); ▪ EXCLUDE Exemptions = STPIS MED day or Public Safety Isolation (Exemption clause: 3.3 (a) (7)).
Average Distribution Customer Numbers	The average number of customers on each of the feeder categories is calculated by adding the feeder category customer numbers at the start of the financial year (1 July) and feeder category customer numbers at the end of the financial year (30 June) and dividing the total by two. Average number of distribution customers for whole of network is the total of averages of UR, SR and LR Customer numbers.

Template 1b – STPIS Customer Service

Template 1b Customer Service requires Ergon Energy to enter STPIS information concerning customer service parameters set out in the AER's Electricity Distribution Network Service Provider (DNSP), STPIS (November 2009), as applicable to Ergon Energy for the current regulatory control period. All results reported in Total, and after removal of excludable events.

Information is not required to be completed by Ergon Energy on new connections, streetlight repairs and responses to written enquiries (excluding Saturdays, Sundays and Public Holidays).

Ergon Energy makes the following comments in regards to the completed table for telephone answering in Template 1b.

Table 4-46: Template 1b - STPIS Telephone Answering

Item	Assumptions and methodology
Telephone Answering	Ergon Energy provides a specific telephone line, which receives calls on 132296 and 131670, for electricity outage related calls and uses the Avaya Call Management System (CMS) Supervisor, an industry wide system developed by Avaya Inc. to process telephone calls. The fault call system is used to distribute calls to Ergon Energy operators at the National Contact Centre and its functions include, but are not limited to: ▪ Recording volume of calls received at the call centre; ▪ Recording the length of time between a caller entering the system and the call answered by an operator; and ▪ Recording the length of time between a caller entering the system and the caller abandoning the call. The system plays an Interactive Voice Recording (IVR) message prior to queuing the call for response by an operator. As stipulated in Appendix A of the STPIS, the time measured for a call begins after the caller decides to remain on the line after the IVR is played. Monthly telephone data is extracted from the Avaya CMS Supervisor using functions within the systems Graphical User Interface (GUI) by the Channel Operation Analyst and exported into an Excel spread sheet, to be entered into the parameters listed in Table12b.1 of the RIN. All totals exclude calls relating to an excluded event.

Template 1c – STPIS daily performance

Template 1c STPIS daily performance, requires Ergon Energy to enter daily STPIS information concerning both reliability and customer service parameters set out in the AER's Electricity DNSPs, STPIS (November 2009), as applicable to Ergon Energy for the current regulatory control period.

The AER state the information is required is relative to Unplanned SAIDI/SAIFI only. The excluded events to be removed from the data refer only to events listed in clause 3.3(a) of the STPIS, with respect to reliability data, and in clause 5.4(a) of the STPIS with respect to customer service parameters.

Ergon Energy makes the following comments in this regard, for Reliability and Customer Service data.

Table 4-47: Template 1c - STPIS Daily performance data (Unplanned SAIDI and SAIFI)

Item	Assumptions and methodology
Daily performance data (Unplanned SAIDI, Unplanned SAIFI)	All reporting for RoS component of STPIS are based on the network outage data retrieved from FDRSTAT Oracle Database Tables recorded for the relevant regulatory year. When a MED day is declared, cleansing of all the outage data may not be conducted for that day due to the extraordinarily high volume of outages. Therefore there could be some discrepancies in that day's data. However, the outages that are tagged as being eligible for exemption other than MEDs are checked for validation of exemption eligibility purpose. Distribution Feeders are categorised as UR, SR or LR as per the definitions in Appendix A of the AER's Electricity DNSPs, STPIS (November 2009). Reporting is based on the feeder category that a feeder is considered to be at the end of the regulatory year as at 30 June. "Date" - refers to the date on which the daily SAIDI/SAIFI were recorded, formatted to DD:MM:YY. For daily unplanned SAIDI/SAIFI for each feeder category "All events total", the sustained

Item	Assumptions and methodology
	unplanned outages data must fit the following criteria: ▪ Outage Type = Unplanned or Forced; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1 July 2012 and 30 June 2013; ▪ Feeder Categorisation = [insert - feeder category]; ▪ Outage Maximum Duration is > 1 Min; ▪ INCLUDE Events = Normal; or Service Fuse or Beyond; or Generation (Exemption clause: 3.3 (a) (2)); or Shared Transmission (Exemption clause: 3.3 (a) (5)); ▪ INCLUDE Exemptions = STPIS MED day; or Public Safety Isolation (Exemption clause: 3.3 (a) (7)). For daily unplanned SAIDI/SAIFI for each feeder category "All events – after removing excluded events", the unplanned sustained outages data must fit the following criteria: ▪ Outage Type = Unplanned or Forced; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1st July 2012 and 30th June 2013; ▪ Feeder Categorisation = [insert - feeder category]; ▪ Outage Maximum Duration is > 1 Min; ▪ INCLUDE Events = Normal or Service Fuse or Beyond; ▪ EXCLUDE Events = Generation (Exemption clause: 3.3 (a) (2)); or ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)); ▪ EXCLUDE Exemptions = STPIS MED day; or Public Safety Isolation (Exemption clause: 3.3 (a) (7)). For daily unplanned SAIDI/SAIFI Network "All events total", the unplanned sustained outages data must fit the following criteria: ▪ Outage Type = Unplanned or Forced; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1 July 2012 and 30 June 2013; ▪ Feeder Categorisation = [Any active feeders in the network]; ▪ Outage Maximum Duration is > 1 Min; ▪ INCLUDE Events = Normal; or ▪ Service Fuse or Beyond; or ▪ Generation (Exemption clause: 3.3 (a) (2)); or ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)); ▪ INCLUDE Exemptions = STPIS MED day; or Public Safety Isolation (Exemption clause: 3.3 (a) (7)). For daily unplanned SAIDI/SAIFI Network "All events – after removing excluded events", the unplanned sustained outages Data must fit the following criteria to determine the WHOLE NETWORK SAIDI/SAIFI: ▪ Outage Type = Unplanned or Forced;

Item	Assumptions and methodology
	▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1st July 2012 and 30th June 2013; ▪ Feeder Categorisation = [Any active feeders in the network]; ▪ Outage Maximum Duration is > 1 Min; ▪ INCLUDE Events = Normal; or ▪ Service Fuse or Beyond; ▪ EXCLUDE Events = Generation (Exemption clause: 3.3 (a) (2)); or ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)); ▪ EXCLUDE Exemptions = STPIS MED day; or ▪ Public Safety Isolation (Exemption clause: 3.3 (a) (7)).
Daily performance data Customer Service	Ergon Energy provides a specific telephone line, which receives calls on 132296 and 131670, for electricity outage related calls and uses the Avaya CMS Supervisor, an industry wide system developed by Avaya Inc. to process telephone calls. The fault call system is used to distribute calls to Ergon Energy operators at the National Contact Centre and its functions include, but are not limited to: ▪ Recording volume of calls received at the call centre; ▪ Recording the length of time between a caller entering the system and the call answered by an operator; and ▪ Recording the length of time between a caller entering the system and the caller abandoning the call. The system plays an IVR message prior to queuing the call for response by an operator. As stipulated in Appendix A of the STPIS, the time measured for a call begins after the caller decides to remain on the line after the IVR is played. Daily telephone data is extracted from the Avaya CMS Supervisor using functions within the systems GUI by the Channel Operation Analyst and exported into an Excel spread sheet (STPIS GOS 12-13.xlsx), to be entered into the parameters listed in TableT1c of the RIN. All totals exclude calls relating to an excluded event.

Template 1d – STPIS – MED threshold

Template 1d requires Ergon Energy to provide information pertaining to MED threshold calculations. MED calculation Table 1d.2 requires information on all unplanned events pertaining to Network SAIDI after removing excluded events allowed under clause 3.3(a) of the STPIS. Further, information on total unplanned customer minutes off supply after removing excluded events allowed under clause 3.3(a) of the STPIS are to be included in this template.

The following comments are made with regards to MED calculations.

Table 4-48: Template 1d - STPIS MED Threshold - MED Calculation

Item	Assumptions and Methodology
STPIS MED Threshold & Calculation	Exclusions are applied in accordance with clauses 3.3(a) (for RoS Reporting) of the AER's Electricity DNSPs, STPIS (November 2009). FDRSTAT has provision for different outage flags that are also applied to tag the outages for

	exclusions appropriately. The Major Event Day threshold (TMED) applicable under the STPIS for the regulatory year 2012/13 was calculated as per Appendix D of Electricity DNSPs, STPIS (November 2009). This is based on the IEEE1366 2.5 beta methodology. For the regulatory year 2012/13 the TMED applied was 8.52 system unplanned SAIDI. Template 1d – Table 2 has been populated with the 5 years' of historical daily SAIDI data that were utilised for the TMED calculation. Note: Formula for Cell C14, Beta-standard deviation of Ln(SAIDI), has been amended to use the function STDEVP (instead of STDEV) as per the AER's 22 Aug 2013 email response to Ergon Energy's query on the appropriate formula for the calculation of Beta. A row was also found missing from the data set which Ergon Energy has included. Specific to Network daily SAIDI unplanned and the total unplanned customer minutes off supply reported, Ergon Energy makes the following comments: The following criteria are applied to unplanned Outages Data used to calculate the daily SAIDIs listed in 1d: ▪ Outage Type = Unplanned or Forced; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1 July and 30 June of each of the 5 regulatory years between 2007/08 and 2008/09; ▪ INCLUDE Events = Normal; or Service Fuse or Beyond; ▪ EXCLUDE Events = Generation (Exemption clause: 3.3 (a) (2)); or Shared Transmission (Exemption clause: 3.3 (a) (5)); or Public Safety Isolations (Exemption clause: 3.3 (a) (7)); ▪ INCLUDE Exemptions = STPIS MED day.

Template 1e – STPIS exclusions

Template 1e requires Ergon Energy to provide information pertaining to Exclusions made. Ergon Energy understands that this information is collected to inform the application of the STPIS to the DNSP in future regulatory periods, and is also connected to monitor network performance and may be used in performance reports.

Ergon Energy employs a fault categorisation system simple enough to facilitate and promote consistent and accurate data entry from field and control room staff, whilst providing the network planners and asset managers with sufficient information to monitor and manage network reliability.

When unplanned outages occur the outage is recorded into FDRSTAT and followed by a cause classification code when the cause of the interruption is known, as outlined in FDRSTAT Online Manual Ver 3.9.12. When the cause of an interruption remains marked as unknown, the Ergon Energy Network Reliability Data Team interrogates these unknown cause classifications in the FDRSTAT system and assigns the appropriate cause classification code to that particular interruption in consultation with Depot and Control Centre Staff. This ensures that only those outages with a truly unknown cause are classified in this way in the FDRSTAT system. The main interest is in defining exclusion events. It is a requirement to be able to distinguish between excluded and non-excluded interruptions as defined under Clause 3.3 of the STPIS.

Table 4-49: Template 1e - STPIS Exclusions – Exclusions

Item	Assumptions and Methodology
Exclusions	All the reporting for RoS component of STPIS are based on the network outage data retrieved from FDRSTAT Oracle Database Tables recorded for the relevant regulatory year. Exclusions are applied in accordance with clauses 3.3(a) (for RoS Reporting) of the AER's Electricity DNSPs, STPIS (November 2009). FDRSTAT has provision for different outage flags that are also applied to tag the outages for exclusions appropriately. The listing of outages also includes outages that fall on a MED day and also have a non-MED exclusion compliance under STPIS. These outages are also listed in Template 5a. The TMED applicable under the STPIS for the regulatory year 2012/13 has been calculated as per Appendix D of AER's Electricity DNSPs, STPIS (November 2009). For 2012/13 the TMED applied was 8.52 system unplanned SAIDI. "Date" - refers to the date that the Outage Event commenced on, formatted to DD:MM:YY. "Outage ID" has been reported as the Outage Event Unique Identifier in FDRSTAT. Feeder IDs are the unique IDs as used to identify the feeders in the FDRSTAT asset data system. Distribution feeders are categorised as UR, SR or LR as per the definitions in Appendix A of the AER's Electricity DNSPs, STPIS (November 2009). Reporting is based on the feeder Category that a feeder is considered to be at the end of the regulatory year as at 30 June. “Number of Customers Interrupted” represents the Number of Customers Interrupted on a Feeder affected by the Interruption. One outage could be interrupting supply in multiple Feeder Categories such as both UR and SR Feeder customers. Reason for Outage: Different outage causes recorded in FDRSTAT have been assigned the high level ‘Cause of Event’ category as provided by the AER in the RIN. E.g. All the Power Link originated unplanned outages are grouped under ‘Transmission failure’. Following criteria are applied to Sustained Outages Data to report for template 1e: ▪ Outage Type = Unplanned or Forced; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1 July 2012 and 30 June 2013; ▪ Feeder Categorisation = UR; or SR; or LR;Outage Maximum Duration is > 1 Min; ▪ INCLUDE Exemptions = Generation (Exemption clause: 3.3 (a) (2)); or ▪ Shared Transmission (Exemption clause: 3.3 (a) (5)); ▪ INCLUDE Exemptions = Public Safety Isolation (Exemption clause: 3.3 (a) (7)); ▪ EXCLUDE Exemptions = MED; ▪ The outages attributable to each exclusion are then set in the criteria using unique tags (e.g. the outages attributable to Generation Shortfall are tagged with flag 'G' in FDRSTAT, etc). “Duration of Interruption” records the minutes from the commencement of the outage event (when first customer is off) to the time when the customers interrupted equals zero (when last customer is restored with supply permanently). “Total Unplanned customer minutes off supply” records the total unplanned customers minutes experienced on the feeder affected due to the Interruption "Event category (referring to the above excluded items definitions)", is taken from the outage exempt field translating to the following:

Item	Assumptions and Methodology
	▪ 2 = (Outage flag 'G') (Exemption clause: 3.3 (a) (2)) load shedding due to generation shortfall; ▪ 5 = (Outage flag 'T') (Exemption clause: 3.3 (a) (5)) load interruptions caused by a failure of the shared transmission network; ▪ 7 = (Outage flag 'F') (Exemption clause: 3.3 (a) (7)) load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP. "Unplanned SAIDI impact" represents the contribution to an individual feeder's unplanned SAIDI minutes by an outage event. Unplanned SAIDI Contribution = Total customer minutes due to the outage/average number of customers in the particular feeder impacted by the outage. For example, if an outage has contributed 1,000 customer minutes to an UR feeder A, then Unplanned SAIDI contribution = 1,000/average no. of customer on UR feeder A (x) = *1,000/x* "Unplanned SAIFI impact" represents the contribution to an individual feeder's unplanned SAIFI by an outage event. Unplanned SAIFI Contribution = Total customer interruptions due to the outage/average number of customers in the particular feeder impacted by the outage. For example, if an outage has contributed 1,000 customer interruptions to an UR feeder A, then Unplanned SAIFI contribution = 1,000/Average no. of customer on UR feeder A (x) = 1,000/x "Further Information" column includes a description of the event and reasons for the exclusion of the event as outlined in the "Event category" column. For example, failure of the shared transmission network due to fires or the right provided under jurisdictional legislation to interrupt supply) and/or a description of the event. Specific to the exclusions reported, Ergon Energy makes the following comments: ▪ For the financial year 2012/13, there were no outages on Ergon Energy's distribution network that could be excluded as "Load shedding due to a generation shortfall". ▪ For the financial year 2012/13, there were no outages on Ergon Energy's distribution network that could be excluded as "Automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under frequency condition". ▪ For the financial year 2012/13, there were no outages on Ergon Energy's distribution network that could be excluded as "Load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator". ▪ For the regulatory year 2012/13, there were 225 Network outages that were attributable to transmission network service provider Powerlink's supply network, and excluded under "Load interruptions caused by a failure of the shared transmission network". ▪ For the financial year 2012/13, there were no outages on Ergon Energy's distribution network that could be excluded under "Load interruptions caused by a

Item	Assumptions and Methodology
	failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning". ▪ Most of the outages excluded under "Load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP" are attributable to the aftermaths of the tropical cyclone Oswald and extensive floods in the central and southern supply regions during the wet season of 2012/13.

Template 1f – STPIS GSL

Template 1f requires Ergon Energy to provide information on the AER's GSL scheme. Ergon Energy understands that the information is collected by the AER to inform the application of the STPIS to the DNSP in future regulatory periods. The AER state this information is also collected to monitor network performance, and may be used in performance reports. It is noted that if the AER's GSL scheme has been applied at any time during the regulatory year, Table 1f.1 must be completed. However, if the scheme has not been applied during the regulatory control period, then Ergon Energy does not need to complete this table.

The AER's GSL Scheme did not apply to Ergon Energy at any time during the regulatory year, therefore reporting for this template does not apply.

Template 2 – Demand

Template 2 requires Ergon Energy to report maximum coincident demand at the network level and summer and winter non-coincident maximum demand by zone substation (ZSS). Ergon Energy understands that this information is required to assess forecasts against outturn demand and will form the AERs review of demand forecasts in future regulatory proposals. It may also be used in performance reports.

Forecasts in Table 1 should be the demand forecasts for the relevant regulatory year that were made at the time of the regulatory proposal, and t+1 forecasts should be the latest updates to the demand forecasts for the regulatory year t+1.

Ergon Energy maintains a series of secure, managed databases known as the Statistical Metering Database (SMDB) that contain historic demand and weather (sourced from the Bureau of Meteorology data). For the purpose of data auditing, full version control of the metered data is maintained within SMDB and the database is regularly backed-up. Access to the environment is secure and provided only to those persons who require access in order to conduct and manage the load forecasting process, and planning studies, with any changes to the datasets tracked and recorded.

The database is constantly being fed new demand data from a variety of sources including:

- AEMO accredited Meter Data Agents (MDA) for:
  - All National Energy Market (NEM) meter data file formatted (MDFF) data for Transmission Connection Points (and hence Ergon Energy System Total Demand) and market customer meter data;
  - Dedicated type 4 metering on distribution feeders/power transformers; and
  - Type 4 meter data of non-market customer as interrogated by the Ergon Energy accredited MDA; and

- Supervisory Control and Data Acquisition (SCADA) at the Bulk Supply Points and Zone-Substations (ZSS);
- Other sources within Ergon Energy for:
  - NULEC recloser downloads; and
  - Maximum Demand Indicator (MDI) readings, and
- Simulations of maximum demand based on premises consumption records (billing) and network topology when the above sources are unavailable.

Table 1, Maximum coincident demand at the network level requires Ergon Energy to provide forecast, actual (raw), actual (weather normalised) and forecast for year t+1 network coincident maximum demand at the network level at 90 per cent, 50 per cent and 10 per cent probability of exceedence levels. Colour coding of input sheets as specified by the AER cover sheet state grey cells as - no input required.

Forecasts should be the demand forecasts for the relevant regulatory year that were made at the time of the regulatory proposal; t+1 forecasts should be the latest updates to the demand forecasts for the regulatory year t+1.

Ergon Energy makes the following comments regarding Table 1.

Table 4-50: Template 2 - Demand - Maximum coincident demand at the network level

Item	Assumptions and Methodology
Maximum coincident demand at the network level	90% Probability of Exceedance (PoE) level – this lowest level is obtained from a maximum demand distribution such that 90% of the values exceed this. Cells are coded as grey indicating no data input is required. 50% PoE level – this best estimate level is obtained from a maximum demand distribution such that 50% of the values are each side of this value. 10% PoE level – this highest level is obtained from a maximum demand distribution such that 10% of the values exceed this. 2012/13 forecast as determined by AER Final Decision (May 2010). 90% PoE and 10% PoE forecasts were not assessed in the AER's Queensland Distribution Determination, 2010/11 to 2014/15, Final Decision (May 2010) since Ergon Energy has only just recently provided the methodology and capability to provide this. The actual maximum coincident demand at the network level for 2012/13 period is extracted from the Ergon Energy System Demand data set (known by unique SMDB Location ID of ErGen%IsaNo2 time series) from system daily maximum demand loads and downloaded into an Excel spread sheet. Temperature correction for 50% and 10% PoE system maximum. A large variation exists between forecast and actual maximum coincident demand at the network level - due to a change in the contributors to the maximum demand since the time of the AER FDD necessitated by loads transferred from Ergon Energy to Powerlink. Weather normalised data is derived using the past 50 years of temperatures from weather stations including Cairns, Townsville and Gladstone. System forecasts for year t+1 are obtained from modelling a temperature corrected multivariate regression model. MVA values are not required as indicated by the grey cells and MVA values are not calculated and not available at systems forecast level. Only available at disaggregated spatial level.

Table 2 Summer and winter non-coincident maximum demand by ZSS requires Ergon Energy to provide summer and winter maximum demand by ZSS, forecast; maximum demand, actual demand, actual raw maximum demand; weather normalised (50% PoE adjusted) actual demand maximum; forecast demand for the next financial year (t+1) and nameplate capacity.

Forecasts are the demand forecasts for the relevant regulatory year that were made at the time of the regulatory proposal; t+1 forecasts are the latest updates to the demand forecasts for the regulatory year t+1.

Summer non-coincident maximum demand is peak demand measured in the period 1 October to 31 March. Winter non-coincident maximum demand is peak demand measured in the period 1 April to 20 September.

Ergon Energy notes the following with respect to Table 2.

Table 4-51: Template 2 - Demand - Summer and winter non-coincident maximum demand* by zone substation

Item	Assumptions and Methodology
Summer and winter non-coincident maximum demand by zone substation	Due to a number of agriculture and resource load driven substation maximum demands, Ergon Energy has defined the winter period as months April to September inclusive and summer period as October to March inclusive so as to cover shoulder peaking substations. Forecasts are produced post summer, such that the winter period proceeds the summer in a forecast year. Forecast demand (MW, MVA and MVAr) is as per the Post Summer 2009-10 year Network Demand Forecasts (t+2), which was provided in Ergon Energy's final submission to the AER. Summer and winter non-coincident actual maximum demand by ZSS for the 2012/13 period is obtained (and stored with full version control to the forecasting database) using the Demand/Energy Extractor application within Ergon Energy's Forecasting system that sources the historic half hour demand data from the database outlined above (SMDB). The data is then extracted and imported into the Ergon Energy/Energex demand forecasting tool "Substation Investment Forecast Tool" (SIFT) for the purpose of network demand forecasting. Raw actual demand (MW, MVA and MVAr) is based on half hour average readings. Several 'Actual-raw' demand entries in RIN Template 2 Table 2 were blank. Ergon Energy notes most of these sites either have no metering (particularly on substations that are generally pole mounted transformers in remote areas) or the metering has failed. Historic readings obtained from (in order of preference) dedicated type 4 metering on distribution feeders/power transformers, SCADA, NULEC recloser downloads, MDI readings and finally simulations of maximum demand based on premises consumption records (billing). "Actual - weather normalised" is the recorded raw reading modified by a 50% PoE adjustment factor. The PoE adjustment factor is obtained from a Monty Carlo approach of inputting up to 50 years of daily temperature data into a multi variant model of the seasons daily MD readings. T+1 forecast demand (MW, MVA and MVAr) is derived from application of growth rates obtained from a linear regression of the last 6 recorded seasonal MW maximum demands to a start value which is PoE adjusted from the last recorded actual MD. (PoE adjustment as described in the previous bullet point). These predictions are further modified for approved capital works affecting substation projected demands, adjusted by known future block loads/generation that are considered outside of trend, applying average uncompensated power factors and known load factor correction devices that will be connected to the network. Forecast 12 month period ends with summer. For example 2012/2013 is the 12 month period

Item	Assumptions and Methodology
	ending 01/03/2013 00:00, therefore winter MDs are recorded during period 01/06/2012 00:00 - 01/09/2012 00:00 and summer MDs are recorded during period 01/12/2012 00:00 - 01/03/2013 00:00. Loads supplied by distribution transformers directly connected to the sub transmission (including Single Wire Earth Return (SWER) systems) is not metered and not forecast. Nameplate capacity (MVA) - In cases where the transformers at a customer specific substation are owned by the customer, the contracted authorised demand has been used as the nameplate capacity. Blank entries in the t+1 forecast columns indicate either sub transmission connected premises closures or transferring to the TNSP or a proposed ZSS that was not an approved project at the time of the AER's FDD.

Template 3 – Outcomes Customer Service

Template 3 requires Ergon Energy to provide information on quality of supply, complaints pertaining to technical quality of supply and customer service. Ergon Energy understands that the information provided will be used to monitor the service performance of Ergon Energy and assist the AER understand service outcomes for customers. The AER also state the information will inform the AER's assessment of future service improvement expenditure proposals by the DNSP. As with information provided in other templates the information provided may be used in performance reports.

Table 1 Quality of Supply is not required to be completed.

Ergon Energy makes the following comments on the Complaints – Technical quality of supply (table 2).

Table 4-52: Template 3 - Outcomes Customer Service - Complaints - Technical Quality of Supply

Item	Assumptions and Methodology
Complaints by category (%); and Complaints by Likely Cause (%)	Ergon Energy is unable to report Template 3 Table 2: Complaints – technical quality of supply information in accordance with the 'complaint' definition in the RIN at the level of dissemination required. The RIN defines 'Complaint' and 'Complaints – technical quality of supply', as: ▪ 'Complaint' means a written or verbal expression of dissatisfaction about an action, a proposed action, or a failure to act by a distributor, its employees or contractors. This includes failure by a distributor to observe its published practices or procedures; ▪ 'Complaints – technical quality of supply' means the total number of complaints made to Ergon Energy including all written or emailed complaints, and complaints to the call centre, where the complaint raised issues about voltage variations. Ergon Energy in the past reported complaints in the RIN dissemination required under the Queensland Competition Authority (QCA) Service Quality Guidelines from its system FDRSTAT. However, the term complaints was defined differently: ▪ Complaints - Complaints are to be reported in accordance with Australian Standard 4269:1995, which defines a complaint as 'any expression of dissatisfaction with a product or service offered or provided'.

Item	Assumptions and Methodology
	▪ Ergon Energy's system FDRSTAT captures calls at the first point of contact at this level of dissemination, not a complaint as defined in the RIN. If the RIN definition for complaints, had been more generalised the template would have been populated in accordance with the below table.

Table 4-53: Template 3 - Outcomes Customer Service - Complaints - Technical Quality of Supply (under first point of call criteria)

	2012/13
	Complaints - technical quality of supply - number
Complaints by category (%)	
Low voltage supply	18.44
Voltage dips	4.92
Voltage swell	50.28
Voltage spike (impulsive transient)	3.36
Waveform distortion	4.6
TV or radio interference	3.48
Noise from appliances	0.2
Other	14.72
Complaints by Likely Cause (%)	
Network equipment faulty	17.55
Network interference by NSP equipment	4.69
Network interference by another customer	0.4
Network limitation	42.89
Customer internal problem	12.55
No problem identified	21.37
Environmental	0.48
Other	0.07

Ergon Energy makes the following comments with regards to Template 3, Customer Service.

Ergon Energy maintains a customer information system known as FACOM. All customers on Ergon Energy's network (both market and non-market customers) are stored within this database and customer numbers and information can be extracted from this database using Ergon Energy's ECORP or NetBill applications. A count of the number of street light appliances can also be obtained via NetBill.

The total number of customers for all tariff classes[2] is obtained as a report from the Customer Service Request System (SeRS) as at 30 June of the financial year in question of all National Metering Identifiers (NMIs) with the NMI_STATUS Active, DeEnergised, Greenfield and having a valid TNI_CODE and PRICE_ZONE.

Note: These numbers are based on NMIs which meet connected premise criteria, and do not include connected appliances such as street lights or unmetered supplies associated with these NMIs.

Ergon Energy currently does not maintain a database to capture the entire number of unmetered connections. Street lights that are owned and maintained by third parties and watchman lights, which make

[2] ICCs; CACs; EGs; SACs

up over half of Ergon Energy's unmetered connections parameter reported by Ergon Energy, can be extracted using NetBill and ECORP respectively.

Table 4-54: Template 3 - Outcomes customer service - Customer service

Item	Assumptions and Methodology
Timely provision of services	Numbers provided as sourced from the GSL Reporting database. This stores the historical data for completed stages of services orders. The numbers provided directly relate the service order type of Initial Connection – Consumer (Type 1, subtype 1, stage 6). Those not made on agreed date are defined as having a completed date after the target date.
Timely repair of faulty streetlights	The data capture system (FDRSTAT) is used for capturing streetlight outages, recording the time and date of the outage and the time and date of restoration. However, the system is not configured to categorise streetlight outages as a separate category for reporting purposes. Currently, to report this information would be a labour intensive process, which would involve investigating every entry in FDRSTAT for the year and manually record streetlight outages and the associated data.
Call Centre Performance (number, unless stated)	Calls to call centre fault line: ▪ Ergon Energy uses Telstra Corporation for its telephony services. Telstra provide reporting capability through an online tool called “Telstra Analyser”. This tool allows Ergon Energy employees to analyse call traffic for Ergon Energy inbound services such as 1300 and 13 numbers. It can be used to identify the number of telephone calls made to each telephone number. For the purposes of identifying the number of calls made to the Contact Centre’s fault line this tool provides the relevant totals. The tool is able to identify between fault line calls and customer service calls, the latter is excluded for this requirement. The total includes all calls made, irrespective of whether the customer decided to speak with an operator or terminated the call whilst within the IVR system. The call total can then be entered into the parameters listed in Table 3 of the RIN. Calls to fault line not answered within 30 seconds: ▪ Ergon Energy provides a specific telephone line for electricity outage related calls and uses the Avaya CMS Supervisor, an industry wide system developed by Avaya Inc. to process telephone calls. The fault call system is used to distribute calls to Ergon Energy operators at the National Contact Centre and its functions include, but are not limited to: ▪ Recording volume of calls received at the call centre: ▪ Recording the length of time between a caller entering the system and the call answered by an operator; and ▪ Recording the length of time between a caller entering the system and the caller abandoning the call. The Daily telephone data is extracted from the Avaya CMS Supervisor using functions within the systems GUI by the Channel Operation Analyst and exported into an Excel spread sheet (STPIS GOS 12-13.xlsx). This data is then used to calculate the total number of calls not answered in 30 seconds by subtracting those calls that were answered in 30 seconds from the total number of calls. This can then be entered into the parameters listed in Table 3 of the RIN.

Item	Assumptions and Methodology
	Calls to fault line – average waiting time before call answered: ▪ As the description of the Avaya CMS explains the system is able to provide details of the length of time between a caller entering the system and the call being answered by an operator. This information is extracted using a database tool called Brio Intelligence Explorer which takes data from the Avaya system and presents in the form of a pivot table. The calculation for average wait time is total number of time waiting divided by total number of calls answered. This can then be entered into the parameters listed in Table 3 of the RIN. Calls Abandoned – percentage: ▪ As the description of the Avaya CMS explains the system is able to provide details of the length of time between a caller entering the system and the caller abandoning the call. The daily telephone data is extracted from the Avaya CMS Supervisor using functions within the systems GUI by the Channel Operation Analyst and exported into an Excel spread sheet (STPIS GOS 12-13.xlsx). This data is then used to calculate the total number of calls abandoned and calculate the percentage of all calls recorded in the Avaya system that were abandoned. This can then be entered into the parameters listed in Table 3 of the RIN. Call centre – number of overload events: ▪ As explained above Telstra provide reporting capability through an online tool called “Telstra Analyser”. This provides the ability to report on the number of events where the telephony system is unable to handle the number of calls being presented to it. This results in those calls being diverted to a message advising that it is not possible to connect their call. This report provides details of the date and times of the events and how many calls were impacted. This can then be entered into the parameters listed in Table 3 of the RIN.
Customer complaints (number)	Ergon Energy has reported Customer Service complaints sourced from the FACTS. FACTS is a database capturing all customer feedback (positive and negative) and enquiries regarding GSLs. For the purposes of reporting customer complaints at the dissemination required in Template 3, Ergon Energy has filtered on all negative complaints and has mapped the RIN categories from the existing FACTS subcategories for the 2012/13 financial year.

Template 4 – General information

Template 4 requires Ergon Energy to provide various pieces of more general information about its metered supply points as well as unmetered supply points, energy delivered, line length, customer numbers, number and capacity of transformers, poles and substations. It also requires Ergon Energy to provide details of other information that pertain to distribution losses, network service area and network coincident maximum demand (MW). The number of Full Time Equivalent (FTE) employees is also required.

Ergon Energy understands that the information will enable the AER to better understand the network and service performance outcomes reported by the DNSP. Network characteristics will be used to normalise other information, to assist in any benchmarking or other comparisons between DNSP financial and service performance outcomes.

Ergon Energy makes the following comments with respect to Template 4.

Table 4-55: Template 4 - General Information - Metered supply points

Item	Assumptions and Methodology
Metered Supply Points	Ergon Energy sourced data relevant to the completion of Template 4 Table 1 – Metered supply points from NEMLink. Counts are of unique NMIs that are identified as having Ergon Energy as their local network service provider. Data excludes NMIs where the status is flagged as "Extinct" or "Greenfield". Distribution Loss Factor codes were used to identify the Supply Voltage type allowing for categorisation in accordance with the RIN requirements. Customer Classes (domestic, non-domestic) are identified in NEMLink using the NMI Customer Classification Code. Ergon Energy's actual total number of customers is greater than the sum of the sub-categories reported (and totalled, in the provided formula) due to the exclusions of Isolated feeder class and Isolated and Site Specific supply voltage classifications from the requested dataset. Also a number of customer records having insufficient information in databases to identify readily into the AER categories.

Table 4-56: Template 4 - General Information - Energy delivered

Item	Assumptions and Methodology
Energy Delivered	Supply Voltage as per Table 1. Energy delivered data for non-market customers and Small market customers is collected by meter readers every billing cycle (monthly or 3 monthly) and entered into the FACOM system, which can then be extracted via NetBill. Large market customer data is routinely sent to Ergon Energy by MDAs and entered into the Netbill system. Energy generation data from the EGs is also provided by the MDA and collated into a generation history file. Ergon Energy also makes the following comments: ▪ Individually Calculated Customer (ICC)/Connection Asset Customers (CAC) and SAC energy delivered is as metered at the customer's premise/site; and ▪ EG data is not energy delivered, but is metered export of energy from the customer's premise/site into the distribution network. This energy then becomes available for (metered) energy delivered by other customers, i.e. ICC, CAC and SACs. For this reason the EG export into the network should not be included in the "total" as it would be double counting. The formula has been changed to deduct EG export (i.e. not energy delivered) from the "total" calculation. ▪ GWH sum total rounded to 0 decimal places. ▪ An additional feeder category has been added, transmission, to ensure total energy delivered is representative of the entire data set. Also where energy has been delivered yet standing data in feeder or customer records is incomplete and classified as unknown, the

Table 4-57: Template 4 - General Information - Line length

Item	Assumptions and Methodology
Line Length	Line lengths are sourced from Smallworld. The line criterion is for all 'as constructed' (energised), Ergon Energy or unknown network not part of the unregulated or isolated network. Where Low Voltage (LV) conductor / cable is missing, an inferred length is calculated from average span length times the number of spans. An additional feeder category has been added, transmission, to report the entire data set. ***Line Length (km)*** Sub-transmission, High Voltage (HV), LV line and cable lengths have the following categories: CBD, UR, SR, LR and Transmission. Ergon Energy Feeder categories are used to assign conductor and cable quantities into these categories. Ergon Energy has no CBD feeders. A Transmission category was added to the template as it does not conform in the same context as the other 3 categories by using the reliability formula to derive the category. Separate comments for the following categories: ▪ Subtransmission ▪ Overhead LV ▪ Overhead HV ▪ Underground LV ▪ Underground HV. ***Sub transmission*** The total installed sub transmission line length is from Smallworld data captured in Ergon Energy's RIN_2013_07 warehouse effective as at 1 July 2013. When the ownership of sub transmission network is unknown it is assumed to belong to Ergon Energy. The selection criteria for the value includes all 'as constructed' (energised), Ergon Energy or unknown network not part of the unregulated or isolated network with an operating voltage equal to or greater than 33kV. ***Overhead LV*** The total installed overhead LV line length is inferred from Smallworld data in Ergon Energy's RIN_2013_07 warehouse effective as at 1 July 2013. Ergon Energy entire LV network in Smallworld is incomplete. There is clear evidence that Ergon Energy has LV poles in the field supplying LV to customers without any associated LV conductor or cable. When the ownership of LV network is unknown it is assumed to belong to Ergon Energy. The selection criteria for LV conductor include all 'as constructed' (energised) Ergon Energy or unknown network in the Smallworld LV table and associated LV constructions (poles). The overhead LV value is the result of: ▪ Calculating an average line length per span ▪ Multiplying the average span line length by the number of 'as constructed' Ergon Energy owned LV constructions without a cable and conductor ▪ Subtracting the known isolated LV network length

Item	Assumptions and Methodology
	▪ Adding known Ergon Energy Owned Regulated LV conductor to the value above. Since Ergon Energy last submission the quantity of captured LV has in Smallworld has improved. The amount of LV conductor reported is lower. ***Overhead HV*** The total installed overhead HV line length is extracted from Smallworld data captured in Ergon Energy's RIN_2013_07 warehouse effective as at 1 July 2013. When the ownership of overhead HV network is unknown it is assumed to belong to Ergon Energy. The selection criteria for the value includes all 'as constructed' (energised), Ergon Energy or unknown network not part of the unregulated or isolated network with an operating voltage between 5kV and 22kV. ***Underground LV*** The total installed underground LV cable length is extracted from Smallworld data captured in Ergon Energy's RIN_2013_07 warehouse effective as at 1 July 2013. When the ownership of underground LV network is unknown it is assumed to belong to Ergon Energy. The selection criterion for the value includes all 'as constructed' (energised), Ergon Energy or unknown underground LV network that is not part of the unregulated or isolated network. ***Underground HV*** The total installed underground HV cable length is extracted from Smallworld data mastered in Ergon Energy's RIN_2013_07 warehouse effective as at 1 July 2013. When the ownership of underground HV network is unknown it is assumed to belong to Ergon Energy. The selection criteria for the value includes all 'as constructed' (energised), Ergon Energy or unknown underground HV network not part of the unregulated or isolated network, with an operating voltage between 5kV and 22kV. ***Total Line Length*** The total line length is the sum of sub transmission line and cables, Overhead LV line, Overhead HV line, Underground LV and Underground HV as described above. Quantity changes from the last submission are a consequence of normal business and data improvement activity.

Table 4-58: Template 4 - General Information - Customer numbers

Item	Assumptions and Methodology
Customer numbers	Ergon Energy sourced data relevant to the completion of Template 4 Table 4 – Metered supply points from NEMLink. Counts are of unique NMIs that are identified as having Ergon Energy as their local network service provider. Data excludes NMIs where the status is flagged as "Extinct" or "Greenfield". Distribution Loss Factor codes were used to identify the Supply Voltage type allowing for categorisation in accordance with the RIN requirements. Customer Classes (domestic, non-domestic) are identified in NEMLink using the NMI

Item	Assumptions and Methodology
	Customer Classification Code. Ergon Energy's actual total number of customers is greater than the sum of the sub-categories reported (and totalled, in the provided formula) due to the exclusions of: Isolated feeder class and Isolated and Site Specific supply voltage classifications from the requested dataset. Also a number of customers records having insufficient information in databases to identify readily into the AER categories.

Table 4-59: Template 4 - General Information - Number and capacity of transformers

Item	Assumptions and Methodology
Number and capacity of transformers	The NER defines a transformer as a plant or device that reduces or increases the voltage of alternating current. The total installed transformer capacity value is from a consolidated asset table built from Smallworld, GISEP and Ellipse systems with the data effective as at 1 July 2013 for all ZSS and distribution transformers. Smallworld design data was used to correct data quality errors. Total Installed transformer capacity is the sum of ZSS power transformer capacity and distribution transformer capacity. Records with either unknown ownership or undefined regulatory environment were assumed to be owned by Ergon Energy and belonging to the regulated network. Maximum available rating was used. Only Ergon Energy owned and regulated energised assets were included. Isolated and unregulated assets were excluded.
Sub transmission Zone Transformers	The Asset Category Zone Transformers, Power transformers result from Template 7 is used.
Distribution Transformers	The total distributed transformer count is extracted from a consolidated asset table built from Smallworld, GISEP and Ellipse systems with the data effective as at 1 July 2013. Records with either unknown ownership or undefined regulatory environment were assumed to be owned by Ergon Energy and belonging to the regulated network. The selection criteria for the distribution transformers is for all Ergon Energy owned and regulated energised transformers at Ergon Energy owned and regulated distributed substations sites with isolated assets excluded and unregulated distribution transformers excluded.
Zone substations	The total ZSS count is extracted the GIESP data source captured in Ergon Energy's RIN_ RIN_2013_07 warehouse effective as at 1 July 2013. Records with either unknown ownership or undefined regulatory environment were assumed to be owned by Ergon Energy and belonging to the regulated network. The count included only Bulk supply, Switching Substations and ZSS. Data quality improvements has resulted in a slightly lower number than last year.

Table 4-60: Template 4 - General Information - Unmetered supply points

Item	Assumptions and Methodology
Number of unmetered supply points	Ergon Energy sourced data relevant to the completion of Template 4 Table 6 – Unmetered supply points from NEMLink. Counts are of unique NMIs that are identified as having Ergon Energy as their local network service provider and a network tariff code indicative of an Unmetered Supply, and excludes unmetered street lighting supplies

Table 4-61: Template 4 - General Information - Poles and substations

Item	Assumptions and Methodology
Sub transmission Poles	The sub transmission pole count is from a consolidated asset table built from Smallworld, GISEP and Ellipse systems with the data effective as at 1 July 2013. The selection extracts all Ergon Energy owned, in service, as constructed, and active poles and Towers with voltages 33, 66, 110, 132, and 220 kV. Streetlights and Bollards have not been included in the count. Smallworld conductor is used to assign voltage categories to the pole records extracted from Ellipse. Poles without a voltage assigned have been classified as a distribution pole. This is based on an assumption that the most common poles are distribution poles. ZSS ▪ The total ZSS count is extracted the GIESP data source captured in Ergon Energy's RIN_ RIN_2013_07 warehouse effective as at 1 July 2013. ▪ Records with either unknown ownership or undefined regulatory environment were assumed to be owned by Ergon Energy and belonging to the regulated network. ▪ The count included only Bulk supply, Switching Substations and ZSS. Data quality improvements has resulted in a slightly lower number than last year. Distribution Substations ▪ The total distributed substation count is from Smallworld data, captured in Ergon Energy's RIN_2013_07 warehouse effective as at 1 July 2013. Smallworld was used because of Data Quality considerations in the Ellipse Dataset. ▪ Records with either unknown ownership or undefined regulatory environment were assumed to be owned by Ergon Energy and belonging to the regulated network. ▪ The selection criteria for the distribution substations is for all Ergon Energy owned and regulated energised substations associated with Ergon Energy owned and regulated distribution substations.
Distribution Poles	The distribution pole count is from a consolidated asset table built from Smallworld, GISEP and Ellipse systems with the data effective as at 1 July 2013. The selection extracts all Ergon Energy owned, in service, as constructed and active poles with voltages lower than 33. Wood, concrete and steel streetlights poles and bollard poles are excluded. Smallworld conductor is used to assign voltage categories to the pole records extracted from Ellipse. Poles without a voltage assigned have been classified as a distribution pole. This is based on an assumption that the most common poles are distribution poles.

Table 4-62: Template 4 - General Information - Other information

<table>
<tr><th>Item</th><th>Assumptions and Methodology</th></tr>
<tr><td>Distribution losses (% of purchases)</td><td>The distribution losses have been calculated as the difference between Ergon Energy's total energy inputs from the following sources; from Powerlink Transmission, Energex connection at Postman's Ridge, and (EG's)for the regulated network (including FiT tariff), and is compared to the total energy delivered to regulated connections for the regulatory year period. For the purposes of reporting, the distribution losses have been divided by energy purchases to present as a percentage.</td></tr>
<tr><td>Network Service area (sq. km)</td><td>Obtained from prior reporting against Minimum Service Standards to the QCA; Ergon Energy's network service area hasn't changed.</td></tr>
<tr><td>Network coincident maximum demand (MW)</td><td>The formula is directly linked from Template 2 – Demand.</td></tr>
<tr><td>FTE employees</td><td>The whole of business FTE total is the sum of the FTE of all employees (permanent and fixed term, excluding casual employees and external resources). FTE is a calculated value based on an employee's scheduled hours of work as compared to the total hours of a 9/10 day fortnight as applicable.
Employees on a 9 or 10 day fortnight are considered to have a value of 1 FTE. The FTE of employees working less than a 9 day fortnight is calculated based on their scheduled hours (a Payroll field which determines an employees' base fortnightly pay) / total standard hours of a 9 day fortnight.
An example is an employee working 4 days a week, e.g. 8 hours a day = 64 hours per fortnight. Therefore, 64 hours * 26 fortnights = 1664 hours per year. To determine the FTE value the calculation would be (1664 / 1885) = 0.88 FTE.
Following from this, total annual hours of a 9 day fortnight = 1885, total annual hours of a 10 day fortnight = 2080.
FTE's have been limited to those employed for the provision of direct control services which is SCS and ACS (regulated distribution services).
Retail (e.g. EEQ) has been excluded from the whole of business totals with the exception of the following responsibility centres that are considered by Finance / Commercial Services to allocate 30% of their time / budget to regulated distribution services (e.g. EECL):
<table>
<tr><th>Responsibility Centre</th></tr>
<tr><td>1850 SERVICE CHNL MGMT</td></tr>
<tr><td>1860 NCC MANAGEMENT</td></tr>
<tr><td>1880 NCC ROCKHAMPTON</td></tr>
<tr><td>1890 NCC TOWNSVILLE</td></tr>
<tr><td>1900 CUSTOMER SOLUTIONS</td></tr>
<tr><td>1910 NCC FAULT SHIFT TEAM</td></tr>
<tr><td>1920 ALT CHANNELS</td></tr>
<tr><td>1950 CUSTOMER RESPONSE</td></tr>
<tr><td>1996 HARDSHIP</td></tr>
</table>
The FTE included in this data provision for the employees in the above responsibility centres has therefore been calculated based on 30% of the employees' actual FTE (as per the original definition above) being allocated to EECL and therefore included in the whole of business FTE totals.</td></tr>
</table>

Template 5a – Network data outage

Ergon Energy is required to provide information on Network outages under template 5a.

Ergon Energy understands that the information in Templates 5a, b, c and d is used by the AER to monitor network performance and service outcomes for network customers. It will inform the AER's review of service improvement expenditure in future regulatory control periods.

Ergon Energy makes the following general comments in relation to Template 5a, STPIS data reporting for unplanned outages.

Table 4-63: Template 5a – Network data outage – Unplanned Outages

Item	Assumptions and Methodology
Network Data Outage	All the reporting for the RoS component of STPIS are based on the network outage data retrieved from FDRSTAT Oracle Database Tables recorded for the relevant regulatory year. The listing of the outages is based on Unplanned Normal and SFB Completed Sustained Outages including all MED days and non-MED exclusions for the relevant regulatory year. When a MED day is declared, cleansing of all the outage data may not be conducted for that day due to the extraordinarily high volume of outages. Therefore there could be some discrepancies in that day’s data. However, the outages that are tagged as being eligible for exemption other than MEDs are checked for validation of exemption eligibility purpose. Following criteria are applied to sustained unplanned outage data listed in Template 5a: ▪ Outage Type = Unplanned or Forced; ▪ Outage Status Code = Completed; ▪ Feeder Categorisation = [UR or SR or LR]; ▪ Outage Maximum Duration is > 1 Min; ▪ Actual Start Date is Between 1 July 2012 and 30 June 2013; ▪ INCLUDE Events = Normal; or Service Fuse or Beyond; ▪ INCLUDE Events = Generation (Exemption clause: 3.3 (a) (2)); or Shared Transmission (Exemption clause: 3.3 (a) (5)); ▪ INCLUDE Exemptions = STPIS MED day; or Public Safety Isolations (Exemption clause: 3.3 (a) (7)). "Date" - refers to the date that the outage event commenced on, formatted to DD:MM:YY. "Outage ID" has been reported as the Outage Event Unique Identifier in FDRSTAT. Feeder IDs are the unique IDs as used to identify the feeders in the corporate asset data system. Distribution Feeders are categorised as UR, SR or LR as per the definitions in Appendix A of the AER's Electricity DNSPs, STPIS (November 2009). Reporting is based on the feeder category that a feeder is considered to be at the end of the regulatory year as at 30 June. Reason for Outage: Different outage causes recorded in FDRSTAT have been assigned the high level ‘Cause of Event’ category as provided by the AER in the RIN. For example, vehicle/machinery impact and wind borne object are reported under ‘Third Party Impacts’. "Number of customers interrupted" represents the maximum number of customers interrupted on feeders (by feeder category) during the outage event. For example, one outage could be interrupting supply in multiple feeder categories such as both UR and SR

Item	Assumptions and Methodology
	Feeder customers. "Duration of interruption" records the minutes from the commencement of the outage event (when first customer is off) to the time when the customers interrupted equals zero (when last customer is restored with supply permanently). “Total unplanned customer minutes off supply” records the total unplanned customers minutes experienced on the feeder affected due to the Interruption. "Unplanned SAIDI Impact" represents the contribution to an individual feeder’s unplanned SAIDI minutes by an outage event. Unplanned SAIDI Contribution = Total customer minutes due to the outage/average number of customers in the particular feeder impacted by the outage. For example, if an outage has contributed 1,000 customer minutes to an UR feeder A, then, Unplanned SAIDI contribution = 1,000/average number. of customer on UR feeder A(x) = 1,000/x "Unplanned SAIFI Impact" represents the contribution to an individual feeder’s unplanned SAIFI interrupts by an outage event. Unplanned SAIFI Contribution = Total customer interruptions due to the outage/average number of customers in the particular feeder. For example, if an outage has contributed 1,000 customer interruptions to an UR feeder, then Unplanned SAIFI contribution = 1,000/average number of customers on UR feeder A (x) = 1,000/x

Template 5b – Network data – Feeder Reliability

Ergon Energy is required to provide information on Network Feeder Reliability under template 5b.

Ergon Energy understands that the information collected in Non-Financial Template 5b will be used by AER to inform the application of the STPIS to the DNSP in future regulatory periods. The information is also collected to monitor network performance, and may be used in performance reports.

Ergon Energy makes the following general comments in relation to Template 5b Network Data Feeder data.

Table 4-64: Template 5b – Network data feeder reliability

Item	Assumptions and Methodology
Annual Feeder Reliability Data	All the reporting for RoS component of STPIS is based on the network outage data retrieved from FDRSTAT Oracle Database Tables recorded for the relevant regulatory year. The definitions and methodology used are set out in the AER's Electricity DNSPs, STPIS (November 2009), as applicable to Ergon Energy for the current regulatory control period. Unique Feeder IDs are sourced from the FDRSTAT asset data. The Outages Data from FDRSTAT must fit the following: ▪ Include all distribution feeders that experienced outages during 2012/13; ▪ Outage Status Code: COMPLETED; ▪ Feeder Categorisation’s: UR, SR and LR; ▪ Sustained: Outages > 1 Minute; ▪ Momentary: <= 1min (Ergon Energy does not capture this data therefore unable to provide the data); and ▪ Include all active distribution feeders that did not experience any outages and that

Item	Assumptions and Methodology
	have Customers Attached to the Feeder as at 30 June 2013.
	Geographical location is Ergon Energy's legacy supply regions – i.e. FN (Far North), NQ (Northern Queensland), MK (Mackay), CA (Capricornia), WB (Wide Bay), and SW (South West). Distribution Feeders are categorised as UR, SR or LR as per the definitions in Appendix A of the AER's Electricity DNSPs, STPIS (November 2009). Reporting is based on the feeder category that a feeder is considered to be at the end of the regulatory year as at 30 June. Ergon Energy does not capture momentary interruption data, therefore it is not reported. The average number of customers on a feeder is calculated by adding the total of customers connected to the feeder at the beginning of the regulatory year (1 July) and the end of the regulatory year (30 June) and dividing the total by 2. Consistent with the STPIS definition, a customer is defined as a premise having an assigned NMI. Customer numbers are held in the ECORP database. Length of HV overhead distribution lines contains the total length in km of Ergon Energy owned, as constructed overhead conductors for each feeder. Length of HV underground distribution lines contains the total length in km of Ergon Energy owned, as constructed underground conductors for each feeder. It should be noted that the totals of the above two line length data have no bearing on the feeder category assigned to the distribution feeders for 2012/13 reliability reporting. The data set for above is sourced from the Asset Data system as it stands in the system and the network currently. The line length data that was utilised to assign feeder category were as per the beginning of the regulatory year 2012/13. The maximum demand values on a distribution feeder during the regulatory year are provided in MVA. This is provided by Ergon Energy's Distribution Planning Team through the Current State Assessment report for distribution feeders. These are the MVA values that were utilised to assign the feeder category for the reporting year. For thirty eight (38) of the reported active feeders (with customers connected), the Maximum Demand (MVA) data was not available. 37 out of 38 feeders are either SR or LR where the category is assigned based on line lengths. There are few relatively old feeders for which Maximum Demand data was not available mainly due to lack of SCADA accessibility/metering. Number of unplanned outage records the total number of sustained unplanned interruptions including SFB interruptions that occurred on that distribution feeder during the regulatory year. The sustained outages are defined by the event's Maximum duration being >1 minute for the regulatory year. This data is to be inclusive of ALL the exempted events including the MEDs. Unplanned customer minutes off-supply (including excluded events and MEDs): The total number of unplanned customer minutes due to the interruptions that occurred on that distribution feeder during the regulatory year including the SFB interruptions occurring on the distribution feeder. This data is to be inclusive of ALL the exempted events including the MEDs. The sustained outages are defined by the event's maximum duration being >1 minute for the regulatory year. Unplanned customer minutes off-supply (after removing excluded events and MED): The total number of unplanned customer minutes due to the interruptions that occurred on that distribution feeder during the regulatory year including the SFB interruptions occurring on the distribution feeder. This data is exclusive of ALL the exempted events including the MEDs. The sustained outages are defined by the event's maximum duration being >1 minute for the regulatory year.

Item	Assumptions and Methodology
	Unplanned interruptions (SAIFI) (including excluded events and MEDs). The Unplanned Feeder SAIFI is calculated as follows: ▪ Summated Customer Interruptions for the feeder for the reporting year inclusive of ALL the exempted events including the MEDs; ▪ Average Feeder Customer Numbers supplied by the feeder between the start and the end of the regulatory year; ▪ SAIFI (Summated Feeder Customer Interruptions on the feeder for the year divided by the average number of customers on the feeder for the regulatory year); ▪ Unplanned interruptions (SAIFI) (after removing excluded events and MEDs); The Unplanned Feeder SAIFI is calculated as follows: ▪ Summated Customer Interruptions for the Feeder for the reporting year exclusive of ALL the exempted events including the MEDs; ▪ Average Feeder Customer Numbers supplied by the feeder between the start and the end of the regulatory year; ▪ SAIFI (Summated Feeder Customer Interruptions on the feeder for the year divided by the average number of customers on the feeder for the regulatory year). Number of planned outages represents the number of Planned Interruptions experienced by the feeder for the financial year. This data is inclusive of interruptions that occurred on the MEDs for the reporting year. Planned customer minutes off-supply represents the total Planned Customers Minutes experienced on the feeders that were affected by Planned Interruptions during the reporting year. This data is inclusive of interruptions that occurred on the MEDs for the reporting year. Planned interruptions (SAIFI). The planned feeder SAIFI is calculated as follows: ▪ Summated Planned Customer Interruptions for the feeder for the reporting year inclusive of ALL the exempted events including the MEDs; ▪ Average Feeder Customer Numbers supplied by the feeder between the start and the end of the regulatory year; ▪ SAIFI (Summated feeder planned Customer Interruptions on the feeder for the year divided by the average number of customers on the feeder for the regulatory year).
Energy not supplied	Energy not supplied (unplanned) has been calculated using data reported in Template 5a Network Data Outage – Table 1: Total unplanned customer minutes off supply (Mins) (Column I) multiplied by the average consumption by feeder (in minutes) sourced from FDRSTAT. This is in accordance with methodology (c) average consumption of customers on the feeder based on their billing history in the RIN definition for energy not supplied (unplanned). The calculations are based on current connectivity by feeder and not connectivity at the time of the outage; this has resulted in reporting some zero values in Template 5b for some feeders as feeders no longer exist in the system ECORP. The methodology adopted is irrespective of the time of day the outages occurred. As Ergon Energy reports planned outages in Template 5a Network Data Outage – Table 2: Total planned customer minutes off supply (Mins) (Column I), the methodology applied to calculate Total Energy not supplied is on the same basis as methodology (c) in the definition for Energy not supplied (unplanned).

Template 5c - Network data cause of outages

Template 5c unplanned outages requires Ergon Energy to enter STPIS information concerning unplanned outages for the relevant regulatory year including the MED boundary and unplanned outage information. The definitions and methodology used are set out in the AER's Electricity DNSPs, STPIS (November 2009), as applicable to Ergon Energy for the current regulatory control period.

Ergon Energy understands that this information is collected to inform the application of the STPIS to the DNSP in future regulatory control periods. The information is also collected to monitor network performance, and may be used in performance reports.

Ergon Energy makes the following general comments in relation to Template 5c, STPIS data reporting for unplanned outages:

Table 4-65: Template 5c - Network data outages - causes of unplanned sustained outages

<table>
<tr><th>Item</th><th>Assumptions and Methodology</th></tr>
<tr><td>Causes of unplanned sustained outages</td><td>Template 5c doesn’t require any data input as such. It sums up the number of outages (from Template 5a) against the listed outage causes. Ergon Energy however would like to highlight that the formulae used to count the total have resulted in an overstatement of total number of outages, with a simple sum counting multiple rows (in Template 5a) against one outage (in Template 5c).
An outage is likely to have more than one row of records in Template 5a as it may have had more than one feeder type impacted. Formulas in 5c will be counting the ‘outage reason’ multiple times for one outage. An example is provided below. Formulas in Template 5c will count it as 4 outages against “Equipment Failure” while in reality it is one outage with Outage ID ‘A’ due to Equipment failure that impacted 4 different feeders.
<table>
<tr><th>Outage ID</th><th>Feeder ID</th><th>Feeder classification</th><th>Reason for outage</th></tr>
<tr><td>A</td><td>A1</td><td>Urban</td><td>Equipment failure</td></tr>
<tr><td>A</td><td>A2</td><td>Rural short</td><td>Equipment failure</td></tr>
<tr><td>A</td><td>A3</td><td>Urban</td><td>Equipment failure</td></tr>
<tr><td>A</td><td>A4</td><td>Rural Long</td><td>Equipment failure</td></tr>
</table>
</td></tr>
</table>

Template 5d – Outcomes of planned outages

Ergon Energy understands that this information is used to monitor network performance and service outcomes for network customers. It will inform the AER's review of service improvement expenditure in future regulatory control periods.

Ergon Energy makes the following comments with respect to Non-Financial Template 5d.

Table 4-66: Template 5d - Outcomes of planned outages - Planned outages

Item	Assumptions and Methodology
SAIDI & SAIFI – after removing excluded events	All the reporting for Planned SAIDI/SAIFI are based on the network outage data retrieved from FDRSTAT Oracle Database Tables recorded for the relevant regulatory year. The reporting on Planned SAIDI/SAIFI "Total" is based on all Planned Normal and SFB Sustained Outages including all the excludable events under the STPIS for the relevant regulatory year.

Item	Assumptions and Methodology
	For each feeder category, the End of Year Planned SAIDI/SAIFI are calculated by dividing the total of Planned customer minutes and customer interruptions (filtered as per below) for the regulatory year by the average of the numbers of customers on that feeder category at the beginning of the reporting period (1 July) and the number of customers at the end of the reporting period (30 June). For each Feeder Category, in calculating the Planned SAIDI and SAIFI "Total", the Sustained Outages Data must fit the following : ▪ Outage Type = Planned; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1 July 2012 and 30 June 2013; ▪ Feeder Categorisation = [insert feeder category]; ▪ Outage Maximum Duration is > 1 Min; ▪ INCLUDE Events = Normal; or SFB; ▪ INCLUDE Exemptions = STPIS MED day; The Whole of Network Planned SAIDI and SAIFI are calculated by dividing the total of planned customer minutes and customer interruptions on all UR, SR and LR feeder categories (filtered as per below) for the regulatory year by the average of the total numbers of customers on all three feeder categories at the beginning of the reporting period (1 July) and the total number of customers at the end of the reporting period (30 June). For planned SAIDI and SAIFI for Whole of Network of "Total" (refer above), the Sustained Outages Data must fit the following: ▪ Outage Type = Planned; ▪ Outage Status Code = Completed; ▪ Actual Start Date is Between 1 July 2012 and 30 June 2013; Feeder Categorisation = UR; SR; or LR; ▪ Outage Maximum Duration is > 1 Min; ▪ INCLUDE Events = Normal or SFB; ▪ INCLUDE Exemptions = STPIS MED day.

Template 6 – Weighted average cost of debt

Template 6, Weighted Average Cost of Capital contains one table, namely Table 6.1 which requires Ergon Energy to provide its Weighted Average Cost of Debt in percentage terms for the current regulatory control year. The template also requires the specific method of calculation of the Weighted Average Cost of Debt (Ergon Energy's choice) to be fully described - in a separate attachment if required.

Ergon Energy understands that this information will be used to compare the distribution businesses' cost against the benchmark cost of debt. There is no intention to set the regulated cost of debt for a business based on its actual cost of debt.

Ergon Energy notes its Weighted Average Cost of Debt as 7.312% for the 2012/13 year, as provided by QTC, and calculated below.

Table 4-67: Template 6 – Weighted Average Cost of Debt

	CSP	LT CSP	Combined
Book interest rate	6.050%	5.230%	5.974%
QTC administration fee	0.062%	0.111%	0.067%
QTC capital markets fee	0.013%	0.015%	0.013%
QTC total funding cost	6.125%	5.356%	6.040%
Competitive Neutrality Fee	1.079%	1.079%	1.079%
Total cost of debt (quarterly)	7.204%	6.435%	7.119%
Total cost of debt (annualised)	7.401%	6.592%	7.312%

During the 2012/13 financial year, Ergon Energy established a long term strategic debt pool (LT CSP) in addition to the existing Client Specific Pool (CSP). The annualised total cost of debt represents the combined weighted average of the two debt pools. Approximately 90% of Ergon Energy's total debt is held in the CSP with the remaining 10% held in the LT CSP.

The book interest rate is calculated annually by QTC between March and June to apply from the start of the next financial year (1 July). Refer to Attachment [**EE_12/13APRIN_003 Excel tab name: Attachment C CSP & Attachment D CSP and LT CSP**].

The CSP book interest rate effectively amortises the difference between the CSP book and market values on the calculation date over the remaining average term of the debt instruments in the CSP. To simplify the amortisation calculation, QTC uses a single fixed maturity date of 31 March 2015.

To determine the CSP book interest rate, the implied forward QTC yields are used to calculate the future market interest payments required to service the market value of the CSP debt. An optimisation routine is then used to solve for the book interest rate that produces debt service payments that result in the same CSP book and market value as at 31 March 2015.

Please refer to Attachment **[EE_12/13APRIN_003 Excel tab name: Attachments A CSP and Attachment B CSP]** for a summary of the CSP book interest rate calculation.

The LT CSP book rate represents the internal rate of return of the portfolio based on the future interest and cash flows on QTC's bonds in the LT CSP.

The book interest rate equals the effective interest rate as defined under the Australian Accounting Standards.

With regards to specific inputs / method to this calculation, Ergon Energy provides the following comments.

Table 4-68: Template 6 - Weighted average cost of debt (WACC) - Underlying Assumptions and Methodology

Item	Assumptions and Methodology
QTC Administration Fee	A fee levied by the QTC that is directly related to the recovery of costs associated with issuing or obtaining a central pool of debt instruments and/or financial instruments.
QTC Capital Markets Fee	A fee levied by the QTC that is directly related to the recovery of costs associated with the ongoing management of a central pool of debt instruments and/or financial instruments. Note this fee was abolished by QTC, effective 1 July 2013.

Item	Assumptions and Methodology
Competitive Neutrality Fee	A fee levied by Queensland Treasury under the Queensland Code of Practice for Government Owned Corporations' Financial Arrangements, designed to offset the funding cost advantage of a government owned corporation relative to the private sector.

Template 7 – Asset Installation

Ergon Energy understands that this information is used in the AER's replacement capex model. The model is used by the AER to assess forecast replacement capex proposals.

It may also be used to monitor the asset age profile of the business over time. This will be used as a tool to monitor any improvements/deterioration in the overall asset age where capex has been approved to address network asset age.

Ergon Energy makes the following comments in respect of Non-Financial Template 7.

General Comments

Ergon Energy has established an Interim Failure Register to track Plant Failure Rates and Statistics for input to Age Replacement modelling. Initially the failure register covered key unitised substation plant, poles and some unitised distribution plant.

Ergon Energy understands that a key purpose of Template 7 is for the input to an AER REPEX model. Accordingly, the task of data provision for the template has attempted to provide the best quality data for all attributes with a view to filling gaps with best endeavours estimates and inferences in order that a workable REPEX model can be populated with data reflective of Ergon Energy's key network assets.

Age Profile and Data Inference

Ergon Energy has been conscious of the AER's expectations for reporting actual data wherever available, and in the absence of actual data, to provide estimates on a best-endeavours basis where practical. In general, Ergon Energy has reasonable nameplate and age data for a high percentage of poles and substation unitised plant. Data on the nameplate details and age of most other distribution plant, conductor and cable is only available for either relatively recent assets or not at all e.g. Ergon Energy does not record the age of cross arms.

In order to establish the age profile based on 'Year Commissioned' and the asset age at failure for each individual asset, Ergon Energy looks first to Year of Manufacture (YOM). Particularly for its older assets, YOM is the most reliably known and populated attribute on asset age. The general process of establishing YOM for each asset employs, as clear preference, specific records of YOM. In the absence of specific records, Ergon Energy has attempted to infer YOM from related or nearby asset data records. In continued absence of reasonable results, Ergon Energy has attempted to infer near-YOM from records about the manufacturing and available records from Manufacturers. In continued absence of reasonable results, Ergon Energy has used more tenuous relationships to determine an age profile as it is understood that an important end purpose of the RIN Template 7 data is to use it to populate the AER's REPEX model. Similar age inference processes were used during the development of Ergon Energy's internal Condition Based risk Management (CBRM) modelling.

YOM is generally only recorded to the nearest calendar year. RIN Template 9: Asset Installation, for 2010/11 and 2011/12 required data on a financial year basis. It is noted that RIN Template 7 for 2012/13 to 2014/15 now requests data on a calendar year basis and this is a far better fit to the data available in Ergon

Energy's systems. Particularly for its older assets, YOM or Installation is only recorded to the nearest calendar year and this is a good fit. Assets with a YOM of 2004 are shown as 2004 in the age profile.

It is noted that much of the other data in Template 7 is required to be based on the financial year.

Replacement Volumes

Ergon Energy notes this additional reporting parameter compared to the previous 2010-12 RIN Template 9.

Replaced assets for the majority of Line and Distribution categories have been identified from stores issues records against capex replacement and opex failure activity codes as shown in the table below.

Table 4-69: Template 7 - Replacement Volumes

Activity Code	Description	Budget	Inferred Driver
53120	Corrective Reg Lines	OPEX	Failed
53150	Corrective Reg Subs	OPEX	Failed
54100	Forced Regulated Maintenance	OPEX	Failed
C2000	Network Refurbishment	CAPEX	Replaced
C2020	Ageing Asset Replacement	CAPEX	Replaced

Failure Data

Following consultation with the AER during the draft RIN consultation, Ergon Energy has interpreted the definition of asset failure to exclude where an asset can be returned to specification via a maintenance activity as this is considered a 'temporary failure'. Such temporary failures are not included in the failure statistics provided.

Ergon Energy has not kept records of Failed Assets in contemplation of the AER RIN request. However, data on pole maintenance is available.

In order to provide this information, Ergon Energy has been progressively attempting different approaches to bridge this gap and in doing so driving change to corporate systems and reporting that will see this capacity improve over time.

To date, the predominant strategy to identify failures is confined to substation unitised plant and relies on identifying the change of status of items in the asset register either between the annual data snapshots or an earlier approach utilised the fact that specific Asset Tables in Ergon Energy's Ellipse system have been recorded as weekly snapshots to attempt to identify data quality and other metadata issues.

Previously, Ergon Energy developed data search "scripts" to trawl through database snapshots to identify assets with a changed status. The important aspects of the data records were subsequently extracted to provide the requisite failure data.

A yet earlier approach involved manual inspection of work orders to identify specific tasks where assets had failed and been replaced. Of the millions of work orders involved, less than 0.1% provided useful and meaningful failure data for the AER's definition of failure.

A suitable date that defines when an asset has failed is used as the failure date and from it two 'year' attributes are derived;

- Failure Year (Calendar Year) which is used in conjunction with the Year Installed (or YOM) to calculate the life achieved; and

- Failure Year (Financial Year) into which the number of failures is counted (The AER RIN requests failures to be provided for each Financial Year).

As there is a manual component of each of these methods, identified failure records have been recorded in an 'Interim Failure Register'. Asset Failure quantities for each financial year have subsequently been derived from this register. Given the quantities of work orders involved in the manual inspection process, it is possible that some failures have not been identified. Consequently some asset failure quantities may be understated.

Ergon Energy has provided data where available, and if not available or if no failures identified, other data and estimates including rates established for the CBRM modelling have been used (typically covering 3 years of data). Where Ergon Energy believes the data for the year to be reported varies significantly from the trend over two or three years (due to a particularly good or bad year for the asset class), comments have been made in this document. Where systemic failure issues for particular asset classes have been identified, Ergon Energy has also flagged within this document its near future expectations for the statistics based upon this foreknowledge.

Mean and Standard Deviation of Age at Failure

Where specific asset failures that occurred were identified in the financial year reported and the actual year of installation or a quality inferred year was available, the age at failure is calculated by subtracting the YOM from the Calendar Year of Failure. Mean and Standard Deviation are then calculated for the relevant asset class. Standard Deviation has been calculated on the basis of a sample population. Alternatively, where the calculation of the standard deviation is problematic, a default substitute value of the square root of the mean is used. For some asset classes, where asset age is unavailable an industry standard mean life and default substitute value for standard deviation as the square root of the mean has been provided.

Replacement Unit Cost

Ergon Energy's processes and systems are generally structured to a project accounting framework with replacement and refurbishment activities commonly bundled. This introduces considerable difficulty in both analysing and estimating unit cost rates for individual equipment categories as required by this RIN. Attempts are being made to derive unit costs from actual expenditure which is driving adjustments to corporate systems to enable this. However, in many cases this will take a year or two to build data which can be analysed.

Therefore, for this delivery of data, replacement unit cost has been derived from a variety of sources, including direct work order statistics, estimates made for program development and CBRM modelling and our earlier Network Assets Replacement Maintenance capex - opex Summary Model (NARMCOS)_2 model, and validated with SME opinion.

Unit replacement costs include all corporate costs exclusive of corporate overheads.

Refurbished equipment (e.g. pole nailing, transformer refurbishment) has not been considered to have failed, consistent with the RIN Failure definition. Ergon Energy notes that this excludes some significant expenditure associated with life extension activities.

Asset Groups and Categories

Ergon Energy provides the below comments specific to individual asset groups / categories represented in Template 7 of the 2012/13 Non-Financial Regulatory Templates.

Poles

Ergon Energy has disaggregated the Poles group of assets into four sub-categories, namely: Wood poles - not reinforced; Wood poles - reinforced; Concrete/Steel poles and Streetlight (steel) poles. The population of reinforced wood poles was separately identified as an asset category because of the large quantity in the network.

Table 4-70: Template 7 - Poles

RIN requirement	Comments
Installation Date and Quantity	Pole installation year has wherever possible has been derived from the 'treatment year' in Ellipse. This 'treatment year' has been obtained from the manufacturer's treatment disk. Alternatively, the closed date of any replacement works orders against the pole. Where the above information is unavailable Ergon Energy has inferred from nearby associated asset information. A large gap exists for natural poles pre mid 1960s when poles were not fitted with an identification disc. For these natural distribution poles Ergon Energy has inferred an installation date using equal distribution between 1950 and 1964 which is the era when they are known to have been installed. A second large data gap exists for around 20% of poles which have lost or have no disc. For wood poles (both not reinforced and reinforced) this involves poles installed from 1964 to the present which is the era when they were known to be used. For concrete/steel poles, this involves poles installed from 1980 to the present as this is the known era where substantial quantities of concrete and other steel poles were known to have been installed. For steel streetlight poles, this involves poles installed from 1990 to the present as this is the period of time for which installation of underground cable increased and therefore so too did the installation of streetlights on dedicated poles. These poles have been age inferred from nearby poles using structured rules. When this technique fails, the remaining poles are distributed randomly between the earliest year above and the present.
Actual replacement volumes (number of assets replaced)	Replaced assets for the reported year have been identified from stores issues records against replacement activity codes. It is noted that this has revealed that the number of poles failed / replaced by Ergon Energy is approximately four (4) times the numbers failed through the (FMC) preventative maintenance program for the three years.
Asset Failures	Failed assets for the reported year were identified from Ergon Energy's asset management system using defect codes in the Pole Maintenance data from Field Mobile Computing (FMC) that indicate pole replacement has occurred.
Replacement Life	Ergon Energy has calculated the mean and standard deviation replacement life for each pole type/category based upon calculated actual ages of those poles replaced (not reinforced) in the reported year using the actual and inferred ages as described under Installation Date and Quantity. Because there are very few identified failures for concrete/steel poles, the mean age from this analysis is not considered credible and an industry standard life of 50 years for these long life assets has been substituted. A substitute standard deviation in the form of the accepted default value of the square root of the mean life has been provided.

RIN requirement	Comments
Average Replacement Cost	It has not been possible to separate specific cost data associated with pole replacement. Records of actual work performed are generally bundled into larger tasks and it has proved impractical to isolate the specific costs associated with poles from the actual costs of 'defect refurbishment packages'. A unit cost of wood pole replacement estimate was built up based on the field experience with labour and material requirements for a range of pole height and hardware requirements. Using this methodology, the average cost of wood pole replacement is about $2,600 (inclusive of labour to complete the job once on site and material costs only). Estimated cost for steel pole replacement was approximately $2,400. The above figures do not include travel, accommodation and equipment costs. However, the estimating team has come out with a mobilisation factor of 12.4% to account for these costs. Without a specific estimate for concrete poles, an estimated cost of twice that for wood poles has been assumed on the basis these are much larger more expensive structures.

Pole Top Structures

Ergon Energy has disaggregated the Pole Top Structures group of assets into two sub-categories, namely: Pole Tops Wood/Composite and Pole Tops Steel/None.

Given Ergon Energy does not manage pole tops as an asset group; records of actual installation year are not kept. An installation year can only precisely be determined for assets replaced since the Ellipse asset management system was implemented from Works Order analysis.

Table 4-71: Template 7 - Pole Top Structures

RIN requirement	Comments
Installation Date and Quantity	The age of pole tops is determined using the date of replacement of cross-arm where that data exists. If the cross-arm has not been replaced recently, an installation year for the pole top is inferred from the pole installation year which is derived as documented under Poles. The quantity of pole tops is calculated by counting the number of cross-arms sitting in the nameplate data against each pole asset.
Actual replacement volumes (number of assets replaced)	Replaced assets for this category have been identified from stores issues records capex replacement and opex failure activity codes.
Asset Failures	Replaced wood and composite assets for 2010/11 and 2011/12 were identified from Ergon Energy's asset management system using defect codes in the P2 Defect Pole Maintenance data that indicate "Xarm" replacement has occurred. When a pole is replaced, so too are all attached pole tops. Such pole tops have not been included in the failure totals. It has not been possible to analyse the FMC failures for 2012/13 and so the quantity has been estimated by using the 2011/12 defect percentage applied to the 2012/13 pole top population. It has not been possible to find the quantity of failures for pole tops that have steel or no timber or composite cross-arms.
Replacement Life	Ergon Energy cannot provide a mean or standard deviation replacement life for this asset class from auditable data. The methods for assigning a year of installation to these assets are considered only adequate for establishing the age profile of the 'in service' population. SME assumed values have been included based on experience using the assumptions below. For steel/none pole tops the life is expected to be quite long and so a life to match the

RIN requirement	Comments
	concrete/steel pole assumed life and standard deviation has been used as it is likely most of these pole tops will be replaced with the poles they are installed on. An industry standard life of 50 years for these long life assets has been assumed. A substitute standard deviation in the form of the accepted default value of the square root of the mean life has been provided. For timber/composite pole tops, it is known that a significant quantity of timber pole tops are replaced prior to the pole they are installed on and therefore the average life must be less than that of a timber pole. Thus an average life of 25 years for these assets has been assumed. A substitute standard deviation in the form of the accepted default value of the square root of the mean life has been provided.
Average Replacement Cost	The determination of actual costs is not straight forward as records of actual work performed are generally bundled into larger tasks and it proved impractical to isolate the specific costs associated with pole tops from the actual costs of 'defect refurbishment packages'. An average replacement unit cost for pole top replacement has been calculated from analysis of Artemis 7 (A7) data for "J Codes" associated with pole top replacement and repair completed in 2012/13. The average unit cost has been calculated as the quotient of this A7 expenditure divided by the total stores issues of cross-arms against refurbishment / replacement activity codes during 2012/13 as described under Asset Replacements above. This rate has been provided as a best endeavours estimate.

Conductors

Ergon Energy has presented Overhead Conductors as a single sub-category asset under the Conductors asset group, presenting data in circuit kilometres (cct km). Ergon Energy holds very little asset data on the installation date for overhead conductors. Design processes from around 2008 create such data for these assets

Table 4-72: Template 7 - Conductors

RIN requirement	Comments
Installation Date and Quantity	RIN Template 7 is populated from data in the corporate Geographic Information System (GIS). In the case of LV conductor, there is a known gap of around 4,000 circuit kilometres which is not included in Ergon Energy's GIS system. This has been included in Template 7 as there is supportable estimate for the quantity based Ellipse data which clearly identifies LV poles. For sub-transmission lines the date installed is from the conductor in the GIS system. This leaves a significant quantity of conductor with an unknown age. An age has been derived using rules developed for Ergon Energy's CBRM modelling for Distribution HV conductor. The age inferring logic uses the pattern of earliest pole age supporting the conductor which is then cross checked with the approximate date range (era) that the various conductors are known to have been in use. This HV profile has been used to shape the total quantity of LV conductor including the unknown LV and sub-transmission conductor.
Actual replacement volumes (number of assets replaced)	Replaced assets for the reported year have been identified from stores issues records against capex replacement activity codes. These stores issues are then converted to circuit kilometres using ratios of metres issued to circuit kilometres estimated for the various conductor family types. An attempt has been made to reconcile the replacement volumes from stores issues with GIS data. A correlation has not been able to be identified thus far and further work will be required at a future time.

RIN requirement	Comments
Asset Failures	Asset failures for the reported year are compiled from the subset of stores issues records against opex corrective and forced maintenance activity codes
Replacement Life	Because Ergon Energy does not have asset installation dates it has not been possible to calculate statistics on replacement life. Without statistics based on auditable data, an industry standard life of 50 years for this long life asset has been assumed. A standard deviation in the form of the accepted default value of the square root of the mean life has been provided.
Average Replacement Cost	An average replacement unit cost for all conductor replacement has been calculated from analysis Artemis 7 (A7) data for "J Codes" associated with conductor replacement projects completed in 2012/13. The average unit cost has been calculated as the quotient of this A7 expenditure divided by the total circuit kilometres calculated from stores issues of conductor against refurbishment / replacement activity codes during 2012/13 as described under Asset Replacements above.

Underground Cables

Ergon Energy has disaggregated the Underground Cables group of assets into two sub-categories, namely: HV and LV underground cables. Comments below are applicable to either or both sub-categories of assets.

Table 4-73: Template 7 - Underground Cables

RIN requirement	Comments
Installation Date and Quantity	Ergon Energy holds data on cable quantity. Installation date is available on a very small proportion of recent cable. RIN Template 7 is populated from Ergon Energy's CBRM model for HV underground cable. The age profile has been inferred from connected assets, downstream transformers and switchgear. Ergon Energy notes there is a small disparity between the total quantity of HV cable in the RIN snapshot database and the earlier data extraction for the CBRM model data. RIN Template 7 is populated with a single total circuit kilometres from the RIN snapshot database for LV Underground Cable. A supportable age profile has been produced by inferring that the LV cable will have been installed in parallel with the HV.
Actual replacement volumes (number of assets replaced)	Replaced assets for the reported year have been identified from stores issues records against both failure and replacement activity codes. These stores issues are then converted to circuit kilometres using ratios of metres issued to circuit kilometres estimated for the various cable types.
Asset Failures	The failure rate has been extracted from stores issues against relevant activity codes. The three activity codes below are used to select the data associated with opex corrective maintenance and it has been assumed that this might be the proportion of failed in service assets of the total quantity replaced as calculated from stores issues.
Replacement Life	Similarly, because Ergon Energy does not have reliable asset installation dates it has not been possible to analyse and calculate actual mean and standard deviation of asset life. Without statistics based on auditable data, an industry standard life of 50 years for this long life asset has been assumed. A substitute default standard deviation has been provided as the square root of the mean.

RIN requirement	Comments
Average Replacement Cost	Estimated average direct replacement costs (escalated to reported year dollars via the CPI) for HV and LV underground cable from earlier modelling circa 2009 in NARMCOS_2 as a best endeavours estimate

Services (including LV pillars and LV service pits)

Ergon Energy holds very little asset data on quantity of or installation date for overhead and underground services, pillars and pits. Design processes from around 2008 create such data for these assets.

The Services asset group has been split into disaggregated asset categories, namely:

- Overhead Customer Services; and
- LV Pillars.

Comments are provided separately on each of these asset categories below.

Table 4-74: Template 7 - Overhead Customer Services

RIN requirement	Comments
Installation Date and Quantity	Ergon Energy has been able to provide a total quantity of overhead services based on its GIS data using the following inferring logic: ▪ For each unique premise location – find the nearest structure (pole, pillar, pit and gms) to the premise location; and ▪ If the nearest structure is a pole, assume this is serviced by an overhead service. Ergon Energy cannot provide an age profile of the LV services. There are insufficient records to provide even a reasonable estimate of this profile. The impacts of natural disasters such as cyclones are often considerable, and LV service failures in such situations are common. Cyclones and flooding across Queensland have had significant impact in this area. Post disaster restoration records of LV services replacement have not proven to be effective. Records of prior Ergon Energy entities for LV services are scant. For the purposes of providing data suitable for building an Ergon Energy REPEX model, an age profile based on the combined conductor age profile for sub-transmission and distribution HV and LV conductor has been used to shape the total quantity reported.
Actual replacement volumes (number of assets replaced)	The average LV service length calculated in the GIS from pole and meter GPS co-ordinates is 25 metres. Using this it has been possible to convert the total length of stores service cable usage against the failure and replacement activity codes into an estimated number of services replaced. The five activity codes below are to select the data associated with corrective maintenance or replacement of failed in-service assets. It should be noted that Ergon Energy replaces significant numbers of services due to natural disasters e.g. cyclones and severe storms. Ergon Energy also has an ongoing public safety based replacement program for specific LV services types. New overhead services are only erected for new rural and rural residential network extensions.
Asset Failures	The failure rate has been extracted from stores issues against relevant activity codes. The three activity codes used are associated with corrective maintenance and it has been assumed that this might be the proportion of failed in service assets.

RIN requirement	Comments
Replacement Life	In the absence of any reasonable estimation of individual service age, Ergon Energy is unable to provide a calculated mean and standard deviation of failure age for this asset category. Given Ergon Energy's exposure to widespread natural disasters such as cyclones, Ergon Energy expects that the mean asset life achieved would be considerably lower than the Australian DNSP averages. In the absence of data, an SME estimate of the likely service life has been provided. In addition, a substitute standard deviation in the form of the accepted default value of the square root of the mean life has been provided.
Average Replacement Cost	Ergon Energy has been unable to determine specific cost data for average LV service replacement cost. Records of actual work performed under emergency conditions are generally bundled into larger tasks and it proved impractical to isolate the specific costs associated with this asset sub-class. A single rate has therefore been provided from NARMCOS_2 (increased by CPI) for a best endeavours estimate.

Table 4-75: Template 7 - LV Pillars

RIN requirement	Comments
Installation Date and Quantity	Ergon Energy has provided a total count of Pillar Boxes from a count of this specific asset in the Ellipse Asset Register. Ellipse does not hold data for the age of the Pillar Boxes. There are 135,365 service pillars (Equipment Class = ‘PB’) in Ellipse. A second data set for pillars exists in the Smallworld GIS. This data shows a total of 92,163 pillars in the GIS of which 51,089 have age details. It is not known how reliable this is, but it looks credible from an SME perspective of when most of the Underground Residential Distribution (URD) would have been installed. A supportable age profile has been produced by inferring that the total population of LV pillars will have an age profile that matches the shape of the age profile of the pillars that it has been able to determine a year of installation from data in the GIS.
Actual replacement volumes (number of assets replaced)	Replaced assets for pillars for the past 3 years have been identified from stores issues records against replacement and failure activity codes. For the asset type pillar boxes the material to be issued from stores consists of two parts for most types, a base and a cover. An analysis of the stores issues shows that there are consistently more covers issued than bases which would be expected. For the purposes of counting failures the number of covers has been used.
Asset Failures	It has not been possible to find failed assets for this asset sub-category (see Replacement Life commentary).
Replacement Life	Because Ergon Energy does not have reliable asset installation date it has not been possible to analyse and calculate actual mean and standard deviation of asset life. Without statistics based on auditable data, an SME estimated life of 36 years for this asset has been assumed. A substitute default standard deviation has been provided as the square root of the mean.
Average Replacement Cost	An average pillar direct replacement unit cost has been provided from NARMCOS_2 increased by CPI.

Distribution Transformers

The Distribution Transformers asset group has been split into disaggregated asset categories, namely:

- Distribution Transformers/Reactors; and
- Distribution Regulators.

Comments are provided separately on each of these asset categories.

Table 4-76: Template 7 - Distribution Transformers /Reactors

RIN requirement	Comments
Installation Date and Quantity	Age profile data has been provided from the Ergon Energy annual corporate data snapshot. Ergon Energy employs run to end of life strategies for these assets and YOM /Installation has not been routinely collected. Only a very small number of assets have year of installation and/or manufacture recorded. Ergon Energy has developed a CBRM model for distribution transformers/reactors. Where unknown, the year of installation is derived by inferring the age of the asset from the age of the pole to which the asset is attached. The relationship between the pole age and attached asset has not been tested. The age profile for RIN Template 7 has used this age inferring rules. Distribution Transformers includes: ▪ Pole and GMS mounted distribution transformers (TR/DT), SWER isolators (TR/TI) and reactors (GF/RA); ▪ Local supply transformers (ST/LS) at ZSS sites; and ▪ TR and RX assets from Ellipse not deemed to be power transformers i.e. those with LV primary or secondary voltages, and small (< .5MVA) reactors. Transformer age determined in the following order: ▪ The COMM-DATE (Commissioning Date) nameplate against the transformer physical in Ellipse; ▪ The YOM nameplate against the transformer physical in Ellipse; ▪ The date_installed attribute of the transformer in Smallworld; ▪ The date_installed attribute of the associated substation in Smallworld; ▪ The treatment year nameplate against the pole the transformer is mounted on; ▪ The latest YOM or COMM-DATE nameplates against equipment at the GMS site the transformer is mounted on; and ▪ The earliest premise status date for customers associated with the transformers substation. Where the above logic results in blank or a non-sensible value those assets are distributed to the same shape distribution as the assets with a real or inferred age.
Actual replacement volumes (number of assets replaced)	Replaced assets for distribution transformers for the past 3 years have been identified from stores issues records against replacement and failure activity codes.
Asset Failures	It has not been possible to find failed assets for this asset sub-category (see Replacement Life commentary).

RIN requirement	Comments
Replacement Life	In order to derive statistics on replacement life for 2011/12, a second data set collected in a change of status log appears to represent a small sample of the failures. In turn a subset of this data where an installation year recorded for the failed asset was able to be analysed to obtain a mean and standard deviation life achieved. For 2012/13 the amount of effort for the data able to be found saw this task prioritised down and so a rounded value for mean life of 25 years based on the last two years has been provided. The previous year's analysis showed quite a consistently high standard deviation so a revised standard deviation in the form of the accepted default value of the square root of the mean life has been substituted.
Average Replacement Cost	An estimated average distribution transformer direct replacement unit cost has been provided from NARMCOS_2 modelling increased by CPI.

Table 4-77: Template 7 - Distribution Regulators

RIN requirement	Comments
Installation Date and Quantity	Age profile data has been provided from the Ergon Energy's annual corporate data snapshot. Ergon Energy employs run to end of life strategies for these assets and YOM/Installation has not been routinely collected. Only a very small number of assets have year of installation and/or manufacture recorded. Ergon Energy has developed a CBRM model for distribution regulators. Where unknown, the year of installation is derived by inferring the age of the asset from the age of the pole to which the asset is attached. The relationship between the pole age and attached asset has not been tested. The age profile for RIN Template 7 has used this age inferring method which is similar to that employed for distribution transformers.
Actual replacement volumes (number of assets replaced)	Replaced assets for distribution regulators for the past 3 years have been identified from stores issues records against replacement and failure activity codes.
Asset Failures	It has not been possible to find failed assets for this asset sub-category (see Replacement Life commentary).
Replacement Life	In order to derive statistics on replacement life for 2011/12, a second data set collected in a change of status log appears to represent a small sample of the failures. In turn a subset of this data where an installation year recorded for the failed asset was able to be analysed to obtain a mean and standard deviation life achieved. For 2012/13 the amount of effort for the data able to be found saw this task prioritised down and so a rounded value for mean life of 9 years based on the last two years has been provided. The previous two year's analysis showed quite a variation in standard deviation so a revised standard deviation in the form of the accepted default value of the square root of the mean life has been substituted. Ergon Energy considers the mean life to be low but it is associated with early life failures of a large number of relatively new assets from corrosion.
Average Replacement Cost	An estimated average distribution transformer direct replacement unit cost has been provided from NARMCOS_2 modelling increased by CPI.

Distribution Switchgear

The Distribution Switchgear asset group has been split into disaggregated asset categories, namely:

- Distribution Reclosers;
- Ring Main Units (RMUs);
- Air Break Switches; and
- Gas Break Switches.

Comments are provided separately on each of these asset categories below.

Table 4-78: Template 7 - Distribution Reclosers

RIN requirement	Comments
Installation Date and Quantity	Age profile data has been provided from the Ergon Energy's annual corporate data snapshot. Ergon Energy employs run to end of life strategies for these assets and YOM/Installation has not been routinely collected. Only a very small number of assets have year of installation and/or manufacture recorded. Ergon Energy has developed a CBRM model for distribution regulators. Where unknown, the year of installation is derived by inferring the age of the asset from the age of the pole to which the asset is attached. The relationship between the pole age and attached asset has not been tested. The age profile for RIN Template 7 has used this age inferring method which is similar to that employed for distribution transformers.
Actual replacement volumes (number of assets replaced)	Replaced assets for distribution reclosers for the past 3 years have been identified from stores issues records against replacement and failure activity codes.
Asset Failures	It has not been possible to find failed assets for this asset sub-category (see Replacement Life commentary).
Replacement Life	In order to derive statistics on replacement life for 2011/12, a second data set collected in a change of status log appears to represent a small sample of the failures. In turn a subset of this data where an installation year for the failed asset is available was able to be analysed to obtain a mean and standard deviation life achieved. For 2012/13 the amount of effort for the data able to be found saw this task prioritised down and so a rounded value for mean life of 16 years based on the last two years has been provided. The previous two year's analysis showed quite a variation in standard deviation so a revised standard deviation in the form of the accepted default value of the square root of the mean life has been substituted.
Average Replacement Cost	An estimated average distribution transformer direct replacement unit cost has been provided from NARMCOS_2 modelling increased by CPI.

Table 4-79: Template 7 - Ring Main Units

RIN requirement	Comments
Installation Date and Quantity	Data for Template 9 in for 2011/12 was provided from the Ergon Energy CBRM model for RMUs. Ergon Energy's asset management system for this asset is held as individual switches as opposed to 'boxes' that contain a number of switches (most commonly 3 switches). This required inference to determine which switches comprise an individual asset and the associated year of installation to develop the age profile. This was provided as a best endeavours estimate. For 2012/13 the asset count and age profile have been sourced directly from the Ergon Energy's annual corporate data snapshot. The presence of an RMU remains difficult to identify in the corporate systems, so the logic used was to find all ground mounted sites with more than two HV switches on them, and assume these are RMUs. Unfortunately, this will include some other ground mounted sub sites that aren't RMUs, and it also doesn't account for RMUs mounted at ZSS sites. The hope is that the two approximately cancel each other out. Age Inferring Rules: 1. Get the Build Date against the GMS site. If it's populated and between 1930 and current date then use it. 2. Get the Build Date against the substation mounted on the site. If it's populated and between 1930 and current date then use it. 3. Get the latest date that the Smallworld design was energised when the site was Installed, Upgraded or Replaced. If populated, use this. 4. Get the earliest YOM of Commissioning Date from any Ellipse physicals associated with the site. If populated use this. Where the above logic results in blank or a non-sensible value those assets are distributed to the same shape distribution as the assets with a real or inferred age.
Actual replacement volumes (number of assets replaced)	Replaced assets for distribution RMUs for the past 3 years have been identified from stores issues records against replacement and failure activity codes. Ergon Energy has been overhauling oil insulated RMU equipment over 12 years of age to reduce the risk of failure and to minimise switching restrictions. This has resulted in the replacement of a number of units as a result of the condition and risk identified. Ergon Energy has also had an issue with relatively new ABB SD3 oil RMUs which will have resulted in some replacements. Ergon Energy has also had an issue with relatively new ABB Safelink RMUs which may have resulted in a few replacements.
Asset Failures	It has not been possible to find failed assets for this asset sub-category (see Replacement Life commentary).
Replacement Life	Analysis of assets replaced, sourced from capital projects data, was used to determine the RIN Template 9 failure rate for 2010/11. For subsequent years the amount of effort for the data able to be found saw this task prioritised down and so a mean life based on this 2010/11 has been provided. The previous year's analysis showed quite a high standard deviation so a revised standard deviation in the form of the accepted default value of the square root of the mean life has been substituted.
Average Replacement Cost	Analysis of assets replaced, sourced from capital projects data, and was used to determine the 2010/11 replacement unit cost rate. This has been escalated to the reported year.

Ergon Energy has an Air Break Switch Inspection, Maintenance, Repair and Replacement program which compliments the ground based inspection program to ensure operational functionality and safety of the switch. This maintenance program results in replacement of a percentage of defective switches which are uneconomic to repair, effectively replacement at end of useful life. More recently another replacement program has been introduced to replace specific problematic models where systemic failures present significant safety risks to operators. Ergon Energy also has strategy to replace selected units in key operational locations in its network with higher capability Gas Switches which can switch load current. This means that some Air Break Switch replacements are like for like and some are an upgrade.

Table 4-80: Template 7 - Air Break Switches

RIN requirement	Comments
Installation Date and Quantity	Ergon Energy does not routinely collect or hold YOM/Installation for this asset class. An age profile was extracted from corporate data using similar age inferring methods to other pole mounted plant. The above age profile has then been corrected using the number of assets known to have been installed over the most recent 3 years from stores issue records.
Actual replacement volumes (number of assets replaced)	Ergon Energy has an ongoing program to replace certain models of Australian Bureau of Statistics (ABS) throughout the network for safety reasons. Other emerging issues suggest an increased replacement rate into the medium term. Replaced assets for distribution ABSs for the past 3 years have been identified from stores issues records against replacement and failure activity codes. During the analysis of the stores issues it was noted that some ABS assets are replaced like for like and others are being replaced with higher specification Gas Switches.
Asset Failures	It has not been possible to find failed assets for this asset sub-category (see Replacement Life commentary).
Replacement Life	Ergon Energy was able to identify specific YOM for replaced equipment which has allowed the derivation of failure statistics during 2011/12. For this year the amount of effort for the data able to be found saw this task prioritised down and the mean and standard deviation life based on the 2010/11 analysis has been provided. The mean life determined above is relatively low but this is not unexpected, given the issues noted above.
Average Replacement Cost	Analysis of assets replaced, sourced from Ergon Energy's asset management system data, was used to determine the 2010/11 replacement unit cost rate. An average rate to replace Air Break Switches for the reported year has been calculated based on both the ABS and Gas Switch Unit rates increased by CPI. The quantities replaced with each type included 574 like for like and 522 upgraded to Gas Switches.

Table 4-81: Template 7 - Gas Switches

RIN requirement	Comments
Installation Date and Quantity	Gas Switches are a relatively new asset to be used in Ergon Energy's network. Installation date is more reliably recorded and has been extracted as a starting point for the age profile.

RIN requirement	Comments
	The above age profile has then been corrected using the number of assets known to have been installed over the most recent 3 years from stores issue records.
Actual replacement volumes (number of assets replaced)	Being a very new asset there is no replacement program so the total number of replacements equals the number of failures.
Asset Failures	SMEs advise that a small number of asset failures for Gas Switches are occurring due to early design and implementation issues. A failure quantity has estimated from discussions with standards colleagues involved in the rollout. They have indicated a small number of failures due to low gas, lightning and wildlife contact in the order of 15 per year. This has been included as a best endeavours estimate.
Replacement Life	Being a relatively new asset on Ergon Energy network, Gas Switch assets have not been in use long enough to derive a realistic life expectancy. Ergon Energy anticipates a life expectancy similar to reclosers for this asset class as they are very similar assets. This has been included as a best endeavours estimate.
Average Replacement Cost	An average replacement cost for Gas Break Switches has sourced from an estimated unit cost rate in Ergon Energy 's line standards strategy document "Switching Equipment Application Strategy" (SGMM004) increased by CPI.

Distribution Other Assets

General

No assets reported in this asset category.

Zone Transformers

The population analysed for zone transformers includes power transformers, regulators and large reactors. However no disaggregation of the asset group has been provided.

Table 4-82: Template 7 – Zone Transformers

RIN requirement	Comments
Installation Date and Quantity	The RIN template is populated from the RIN snapshot database.
Actual replacement volumes (number of assets replaced)	Ergon Energy replaced 5 retired transformers in 2012/13 due to planned and asset failure replacement. Ergon Energy defines retired plant by using the change of status from "in service" to "scrap" or "decommission". This identification process has been improved in 2012/13 by adding the change of status procedure in parallel with 2011/12 oil field plant Subject Matter Experts' (SME) scrapping procedure. The actual replacement volume will include the plan replacement, fail on maintenance replacement and fail in service replacement. Each replaced items' replacement status is consulted with the three regional maintenance officers and/or plant SME.

RIN requirement	Comments
Asset Failures	In 2012/13, Asset Failure information is defined as asset fail in service and asset fail on maintenance. This information is gathered by the consultation with oil field plant SME and the regional maintenance officers. The asset failure mode of the replaced asset is recorded in the Ergon Energy Failure Register. The asset failure can be defined as a subset of the actual replaced asset. Asset Failure information for this asset group is provided from the Interim Failure Register. This represents a change to the way failures were counted into each financial year. This improves the accuracy of the data but has the effect of re-shuffling the financial years each asset failed. Ergon Energy reported 4 failures for the 2010/11 RIN Template 9 but the number is now 18. For 2011/12 only one (1) failure occurred. Ergon Energy has therefore included the 3 year average failure rate in Template 9 for 2011/12 as a more appropriate benchmark for internal modelling and for the AER for their REPEX Modelling.
Replacement Life	Ergon Energy's interim failure register has sufficient age information on the failed assets to derive a reasonable estimate of mean and standard deviation life achieved. The 3 year mean and standard deviation has been included in Template 9 to align with the failure rate as discussed above.
Average Replacement Cost	This data has been provided from estimated direct unit cost provided by Ergon Energy standard estimate team as a best endeavours estimate.

Zone Switchgear

The Zone Switchgear asset group has been split into disaggregated asset categories, namely:

- Circuit Breakers; and
- Outdoor Isolators.

Comments are provided separately on each of these asset categories.

Table 4-83: Template 7 - Circuit Breakers

RIN requirement	Comments
Installation Date and Quantity	The RIN Template 7 ages are populated from the RIN snapshot database which is a snapshot in time of Ergon Energy's corporate data systems as at 30 June 2013. Compared to the data in the 2011/12 report, the 2012/13 age profile data fluctuates. This is because in 2012/13 Ergon Energy installed or reinstalled 108 circuit breakers from spare, repaired or plant purchased from the pass.
Actual replacement volumes (number of assets replaced)	Ergon Energy replaced 39 retired circuit breakers in 2012/13 due to planned and asset failure replacement. Ergon Energy defines retired plant by using the change of status from "in service" to "scrap" or "decommission". The actual replacement volume will include three replacement modes, plan replacement, fail on maintenance replacement and fail in service replacement. Each item's replacement status is consulted with the three regional maintenance officers and/or plant SME.
Asset Failures	2012/13 Asset Failure information is defined as asset fail in service and asset fail on maintenance. The asset replacement mode of the replaced asset is recorded in the Ergon Energy Failure Register. The asset failure can be defined as a subset of the actual replaced asset.

RIN requirement	Comments
Replacement Life	Ergon Energy's interim failure register has sufficient age information on the failed assets to derive a reasonable estimate of mean and standard deviation life achieved.
Average Replacement Cost	This data has been provided from estimated direct unit cost provided by Ergon Energy standard estimate team as a best endeavours estimate.

Table 4-84: Template 7 - Outdoor Isolators

RIN requirement	Comments
Installation Date and Quantity	RIN Template 7 is populated from Ergon Energy's cooperate data extract.
Actual replacement volumes (number of assets replaced)	Ergon Energy replaced 60 retired outdoor isolators in 2012/13 due to planned and asset failure replacement. In 2012/13, Ergon Energy used the change of status method to identify the retired outdoor isolator and form a more robust failure register. 60 outdoor isolators are replaced. Ergon Energy also cross checked the failure list with the CBRM data. This leads to a more accurate asset mean life achieved. The actual replacement volume will include the three replacement modes: plan replacement; fail on maintenance replacement; and fail in service replacement. Each replaced items' replacement status is consulted with the three regional maintenance officers.
Asset Failures	Ergon Energy records 56 replaced on fail in service and fail on maintenance, and 4 outdoor isolators are replaced under planned refurbishment situation. In 2010/11, Ergon Energy has not been able to incorporate and analyse failure data for this asset class in Ergon Energy's Interim Failure Register due to the way the data is held in the asset management system.
Replacement Life	2012/13 RIN Template 7 statistical analysis has been improved from last RIN Template 9 submission by using the change of status and cross checking the data with CBRM model. The mean life achieved and standard deviation of the asset class is calculated by using the information from the failure register. 2011/12 RIN Template 9 Analysis of mean and standard deviation life has not been possible for this asset category due to the absence of suitable failure data.
Average Replacement Cost	This data has been provided from estimated direct unit cost provided by Ergon Energy standard estimate team as a best endeavours estimate.

Zone (Other Assets)

The Zone (Other Assets) asset group has been split into disaggregated asset categories, namely:

- Current Transformers;
- VT; and
- Capacitor Banks.

Comments are provided separately on each of these asset categories.

Table 4-85: Template 7 - Current Transformers

RIN requirement	Comments
Installation Date and Quantity	The RIN Template 7 age profile is populated from the RIN snapshot database which is a snapshot in time of Ergon Energy's corporate data systems as at 30 June 2013.
Actual replacement volumes (number of assets replaced)	Ergon Energy replaced 88 retired current transformers in 2012/13 due to planned and asset failure replacement. In 2012/13, Ergon Energy used the change of status method to identify the retired outdoor isolator and form a more robust failure register. 82 current transformers are replaced. The actual replacement volume will include the three replacement modes: plan replacement; fail on maintenance replacement; and fail in service replacement. Each replaced items' replacement status is consulted with the three regional maintenance officers.
Asset Failures	In 2012/13 Asset Failure information is defined as asset fail in service and asset fail on maintenance. The asset replacement mode of the replaced asset is recorded in the Ergon Energy Failure Register. The asset failure can be defined as a subset of the actual replaced asset. There are 82 current transformers replaced in fail in service and fail on maintenance. The 2011/12 asset failure rate for this asset category is provided from the Interim Failure Register. Ergon Energy has some emerging systemic issues with particular current transformers. This has resulted in the replacement of a number of units as a result of the condition and risk identified and is expected to continue into the medium term. CBRM modelling has identified an increase in the medium term replacement rate for this asset category. Ergon Energy has a program to replace a significant number of current transformers over the next 5 years and beyond due to identified risk.
Replacement Life	Ergon Energy's interim failure register has sufficient age information on the failed assets to derive a reasonable estimate of mean and standard deviation life achieved.
Average Replacement Cost	This data has been provided from estimated direct unit cost provided by Ergon Energy standard estimate team as a best endeavours estimate.

Table 4-86: Template 7 - Voltage Transformers

RIN requirement	Comments
Installation Date and Quantity	RIN Template 9 is populated from Ergon Energy's snapshot database.
Actual replacement volumes (number of assets replaced)	Ergon Energy replaced 42 retired VT in 2012/13 due to planned and asset failure replacement. In 2012/13, Ergon Energy used the change of status method to identify the retired outdoor isolator and form a more robust failure register. 39 VT are replaced. The actual replacement volume will include the three replacement modes: plan replacement; fail on maintenance replacement; and fail in service replacement. Each replaced items' replacement status is consulted with the three regional maintenance officers.

RIN requirement	Comments
Asset Failures	In 2012/13 Asset Failure information is defined as asset fail in service and asset fail on maintenance. The asset replacement mode of the replaced asset is recorded in the Ergon Energy Failure Register. The asset failure can be defined as a subset of the actual replaced asset. There are 39 VT replaced in fail in service and fail on maintenance. The 2011/12 asset failure rate for this asset category is provided from the Interim Failure Register. Ergon Energy has observed a recent increase in the number of failures, and expects this trend to continue for some time.
Replacement Life	Ergon Energy's interim failure register has sufficient age information on the failed assets to derive a reasonable estimate of mean and standard deviation life achieved.
Average Replacement Cost	This data has been provided from estimated direct unit cost provided by Ergon Energy standard estimate team as a best endeavours estimate.

Table 4-87: Template 7 - Capacitor Banks

RIN requirement	Comments
Installation Date and Quantity	RIN Template 7 is populated from Ergon Energy's corporate data snapshot for 2012/13. 2012/13 RIN, Ergon Energy only focused on capacitor bank for the purpose of power factor correction. This corrects the population of capacitor bank from 129 to 135.
Actual replacement volumes (number of assets replaced)	There is no capacitor bank replacement in 2012/13 and the site is running on "N" contingency at this stage.
Asset Failures	One capacitor bank failed in 2012/13 with an achieved age of 29 years. Asset failures for capacitor banks are identified from examining the change of status.
Replacement Life	The capacitor that failed in 2012/13 achieved the age of 29 years. As no capacitor banks failed in 2011/12, no replacement life statistics can be calculated. A life expectancy of 35 years has been provided for this asset category based on SME advice as a best endeavours estimate.
Average Replacement Cost	This data has been provided from estimated direct unit cost provided by Ergon Energy standard estimate team as a best endeavours estimate.

SCADA and Protection

The SCADA and Protection asset group has been split into disaggregated asset categories, namely:

- Master Station Servers;
- Remote Terminal Units (RTUs);
- Protection Relays; and
- Audio Frequency Load Control Equipment (HV and LV).

Comments are provided separately on each of these asset categories from Protection and Control as prepared for the 2012/13 RIN Template 7 – Asset Installation.

Table 4-88: Template 7 - Master Station Servers

RIN requirement	Comments
Installation Date and Quantity	Ergon Energy replaced its entire SCADA master systems in 2006 based on SME advice. The servers were used during the development phase and are shown as being procured in a single year.
Actual replacement volumes (number of assets replaced)	In 2012/13, investigations continued with workgroups to ensure no other records exist.
Asset Failures	SME advice indicates there were no failures during 2012/13 and 2011/12 but that several servers were required to be replaced to accommodate manufacturer's software upgrade. The exact number replaced could not be ascertained. A failure rate of 3 has been provided as a best endeavours estimate.
Replacement Life	As it has not been possible to determine the asset failures for 2012/13, no replacement life statistics can be calculated. Based on SME advice, Ergon Energy anticipates a mean replacement life of 5 years with a standard deviation of 0.5 years for this asset category. This has been included as a best endeavours estimate.
Average Replacement Cost	Based on SME advice, a cost to replace a SCADA server has been included as a best endeavours estimate.

Table 4-89: Template 7 - Remote Terminal Units (RTUs)

RIN requirement	Comments
Installation Date and Quantity	Age profile data has been provided from the RIN snapshot database. Approximately 10% of the asset population (~647 units) are of an unknown age. Age profile as per previous records, however any new records introduced in the last year assigned as 'in service' have been allocated to the year 2013 for installation.
Actual replacement volumes (number of assets replaced)	Based upon limited Ergon Energy asset management system records, no RTU replacement were recorded for 2012/13
Asset Failures	It has not been possible to determine a 2012/13 asset failure rate for this asset category. Based upon limited Ergon Energy asset management system records, no RTU failures were recorded for 2012/13.
Replacement Life	Based upon limited Ergon Energy asset management system records no records reflect a replaced RTU for 2012/13. Based on SME advice, Ergon Energy anticipates a mean life expectancy in the order of 15 years with an associated standard deviation of 2.5 years for this asset category. This has been included as a best endeavours estimate.

RIN requirement	Comments
Average Replacement Cost	Based on SME advice, a cost to replace an RTU has been included as a best endeavours estimate.

Table 4-90: Template 7 - Protection Relays

These assets are included in Template 7 as a single category under the SCADA & Protection asset group. Ergon Energy has achieved slightly improved accuracy details (compared to prior year reporting) within data records for model numbers and age.

RIN requirement	Comments
Installation Date and Quantity	Age profile data has been provided from the Ellipse database and incorporates approximately ~9,327 operational relays. August 2013. Approximately ~25% of the asset population is of an unknown age. Due to current asset record processing practices, Ergon Energy has inferred populations and installation dates for assets of an unknown age between 1966 and 2013 giving a distribution to the respective relay model types. Electro-mechanical relay populations have been evenly distributed from 1966 to 1979. Static relay populations are evenly distributed from 1980 to 1989 and numeric relay populations have been evenly distributed between 1990 and 2013, with the exception of the year 2005 due to the installation population spike caused by a data conversion event. Age profile updated from PDS, although a spike in population exists for the year 2005 when a data conversion between Ellipse and PDS was performed. All new numeric relays assigned as 'in service' in the last year have been deemed to be installed 2013/2014. All proposed relay installations which have been approved but not confirmed completed in the field have been evenly allocated to future years 2014 & 2015 until such time that a status has been confirmed either through normal business practices or the rollout of Joint Asset Management Inspection Tool (J-AMIT).
Actual replacement volumes (number of assets replaced)	Based upon limited Ergon Energy asset management system records of a 5 year period between 2007 and 2012 on average 80 relays are replaced every year (with a standard deviation of 39 units).
Asset Failures	For the year 2012/13 approximately 41 relays experienced failure. This is calculated by halving the known replacements for the year 2012 and adding all known failures for 2013 (up to July). However there are no relay failure records for 2013. Due to the lack of information available it is possible to identify if all known replacements are due to asset failure or a part of an asset replacement program. The J-AMIT shall collect protection asset data for collation into Ellipse records and offer details for undefined relays when applied during future maintenance rollouts. In addition, J-AMIT shall also record protection relays status, identify defects during preventive routine maintenance activities.
Replacement Life	As determined for the 5 year period: 2007/2013 that the average replacement life is approximately ~16 years. This average does not take into account the model type of relay (i.e. electro-mechanical, static and numeric) and neglects relays of unknown age. Due to the lack of information available it is possible to identify if all known replacements are

RIN requirement	Comments
	due to asset failure or a part of an asset replacement program.
Average Replacement Cost	Financial estimates to replace a protection relay have been included as a single unit replacement cost of $82,000 (exclusive of Overheads and Uplift factor of 12.4%).

Table 4-91: Template 7 - Audio Frequency Load Control Equipment

These assets are included in Template 7 as two sub-categories to separate the HV component (coupling cell) and the LV control / injection unit (transmitter) due to difference in anticipated life and cost.

RIN requirement	Comments
Installation Date and Quantity	The data provided is held in the Ergon Energy Asset Management System. LV – Of the 49 known operational units in population, 16% are of an unknown age. All new records entered within the last year have been allocated as “in service” and assigned the installation year of 2013. Of these units 4 have been installed for the year 2012/13. HV – Records for this class of unit have not been detailed within Ellipse as yet – thus records reflect no change to the previous submission.
Actual replacement volumes (number of assets replaced)	It has not been possible to determine an accurate 2012/13 replacement volume for this asset category due to limited record data.
Asset Failures	It has not been possible to determine an accurate 2012/13 asset failure rate for this asset category due to limited record data. LV – No records are available to ascertain asset failure. Two units have been removed in the past year however it is perceived that this is due to a rollout of an age asset replacement program as both units were overdue to be replaced. HV – No records are available within the Ergon Energy Asset Management System to ascertain this figure.
Replacement Life	It has not been possible to determine an accurate 2012/13 asset failure rate for this asset category due to limited record data. For the financial year 2012/13 two LV units have been removed. The average replacement life of these units is 31 years. No records are available within the Ergon Energy Asset Management System to ascertain a replacement life value for HV units. Based on SME advice, Ergon Energy anticipates a mean life expectancy in the order of 45 years and a standard deviation of 5 years for the HV component and a mean life expectancy in the order of 15 years and a standard deviation of 5 years for the control / injection unit within this asset category. These have been included as a best endeavours estimates.
Average Replacement Cost	Based on SME advice, the average costs to replace the HV and LV components of an AFLC system has been included as best endeavours estimates.

Other

As in the 2012 RIN, the Meter asset class has been updated under the disaggregated asset categories:

- Meters 1 phase;
- Meters 3 phase;
- Ripple Receivers; and
- LV Current Transformers.

These meter asset classes relate to regulated revenue metering associated with customer metering contained in Ergon Energy's Customer Information System (FACOM). These assets are controlled by a Meter Asset Maintenance Plan approved by AEMO. The plan is based on Chapter 7 of the NER and National Metrology Procedure. The performance of metering installations is highly regulated and focused on the overall accuracy and the ability to measure energy usage that is traceable to the National Measurement Standards. Testing of large meter families is tested in accordance with AS1284.13. A meter installation or family of meters is deemed to have failed if it no longer performs within the required accuracy parameters (i.e. deemed to be non-compliant).

Table 4-92: Template 7 - Other (Meter)

RIN requirement	Comments
Actual replacement volumes (number of assets replaced)	The total asset meter count for 2012/2013 has decreased. This is due to a number of factors, which includes a change in policy to install a single 3 phase meter on all new and replacement situations in lieu of 2 or 3 single phase meters on 2 phase and 3 phase installations. In addition two element meters have been adopted for new and replacement installations in lieu of 2 single phase meters. Large Customers which transfer to a market contract are also removed from the asset count. Meters are replaced for a number of reasons. Over the last 12 months the majority of meter replacements have been due to customer requested tariff updates for Inverter Energy System (IES) installations. Retail tariff reforms has also resulted in a large quantity of meter replacements, while corrective maintenance accounts for other replacements which are predominately reported by meter readers and due to meter failures, damaged meters, and meter error codes. A small number of meters are replaced due to customer requested meter tests where the meter tests outside limits. The removal of meters has been across the age profile. The estimated number of meter removed is 80,000, with 62,700 new meters installed. The removed meter quantities are due to a large number of reasons, including customer requested tariff changes , meter error flags, missing seals, damage, government tariff reforms, supply abolishment's, removed assets associated with Large Tier 2 customer transfers, supply alternations etc. The major contributions to removed meters are estimated to include 55,000 due to solar IES tariff upgrades, 5000 due to corrective maintenance and 2000 due to tariff reform changes. For Ripple receivers approx. 10,000 receivers were removed with approx. 14,800 new receivers installed. Replaced receivers are due to failures associated with cold/hot water complaints, and obsolete receivers that cannot perform to the current installation standards. Current Transformer quantities are associated with Large Customers and the changes in quantities are impacted by transfers of customers to the contestable market. Quantities associated with replacement of current transformers are low due to their reliable nature. Data quality is still being improved as data is updated from field records. Approximately 900 CTs

RIN requirement	Comments
	have been removed due to transfer of responsibility rather than replacement.
Installation Date and Quantity	The age profile spans from the 1940's to current for the total meter count of 1,222,528. Approximately 16,000 new meters are associated with 14,000 new connections. The age profile is built from multiple sources of data including data recorded at the time meters are scrapped, historical supplier records, asset collection at time of field testing as opportunities arise. The majority of these meters are still electromechanical meters, with approx. 16% of the total being electronic meters installed mainly since 2008, as required by legislation. A quantity of 120,000 meters remain installed that are > 50 years old. An estimated 16,000 meters and 4,800 receivers are associated with new customer connections.
Asset Failures	Asset failures have been identified in two electronic meter types. The display is failing on early electronic meters supplied during the 1990's and component failure is occurring in 10 year old 3 phase meters resulting in high registration. These meters are currently being replaced under corrective maintenance as detected. A systemic meter design issue affecting the time keeping ability has been detected in a population of approx. 57,000 single phase electronic meters which renders them unusable as Time of Use meters, but able to be used for energy only tariffs. This problem only became apparent and was detected after they had been in service for a period of more than 3 years. A total of 15,000 meters in stock have been repaired and returned back to stock. A population of approx. 2,200 of these meters installed on Time of Use tariffs will be changed out by the supplier. The reported failure quantities are carryover from identified 14500 EMMCO type BAZ meter in SW region has been declared non-compliant, and project approval given for these to be replaced. The Works Group is assessing resources to undertake this work. A Recommended Works Request (RWR) has been submitted to replace 12500 Schlumberger Type E1 and E2 ripple Receivers in WB region. Current transformers are static devices with low failure rates. A replacement program for current transformers has been operating over the past 10 years to remove very old designs (Bar type current transformers) or where current transformers do not have any nameplate identification to identify what standards they comply with. There remains approximately 134 sites identified that required current transformers to be replaced during 2013/14. This equates to 402 current transformers (= 134 sites * 3 CTs per Site). Many remaining sites are very old and require customers to upgrade their installations. A number of these sites are disconnected from supply, or considered a safety risk.
Replacement Life	The depreciation life for electromechanical meters is 25 years and 15 years for electronic equipment (Meters and Ripple Receivers). The expected working life of electromechanical meters is 40 years and electronic meters are not expected to last more than 20 years. Ripple receivers are expected to last 25 years as these do not have a battery or display. Epoxy Current transformers are expected to last in excess of 40 years. Ergon Energy is developing an aged asset replacement framework to replace meters that are deemed to be non-compliant as a priority, and to target the removal of any meters which are considered "End of Life" where this is > twice the depreciated life of the asset which is 50 years for electromechanical meters. The initial goal is to remove approximately 120,000 meters older than 1963, subject to approval and funding in the next regulatory control period. The current weighted average age of the meter fleet is 24.4 years. The initial goal would be to

RIN requirement	Comments
	lower the weighted average age towards 20. The weighted average age of Ripple receivers is 17 years. 100,000 Ripple receivers are greater than 25 years old.
Average Replacement Cost	Average replacement costs for meters and ripple receivers is based on estimated unit rate, including materials, on site labour, an average of 1 hour travel allowance to attend and rectify a failed asset excluding OH/OCs. (Single phase meter assumption is like for like and 3 phase meter assumes whole current meter – higher cost if current transformer meter site) The cost for LV (current transformers) instrument transformers is based on historical costs and is cost per site divided by 3 to get a per current transformers cost. (i.e. average cost per site = $ 2200, and a site generally has 3 current transformers so cost per current transformer is $ 2200/3 = $ 733) Each customer installation generally has 3 current transformers per site. The estimated cost has been retained from 2012. Cost can vary greatly due to difficultly arranging a customer outage and if this can be done during normal operating hours.

5. MOVEMENTS BETWEEN AUDITED STATUTORY ACCOUNTS AND REGULATORY ACCOUNTING STATEMENTS

RIN - Schedule 1 paragraph 1.1 (d)

REQUIREMENT

Schedule 1 paragraph 1.1 (d) of the Notice requires Ergon Energy to provide a Microsoft Excel workbook or other information that explains all movements between the Audited Statutory Accounts and the Regulatory Accounting Statements.

The AER also requires Ergon Energy to verify specified information, by way of a statutory declaration in accordance with Appendix D to the Notice.

RESPONSE

Please refer to the following Attachment [**EE_1213APRIN_004].**

6. CAPITALISATION POLICY

RIN - Schedule 1 paragraph 1.1 (e)

REQUIREMENT

Schedule 1 paragraph 1.1 (e) of the Notice requires Ergon Energy to provide the Capitalisation Policy for the Relevant Regulatory Year.

The AER also requires Ergon Energy to verify specified information, by way of a statutory declaration in accordance with Appendix D to the Notice.

RESPONSE

Ergon Energy's capitalisation policy is incorporated in its two accounting policies 'Property Plant and Equipment' and 'Intangible Assets' which provide guidance in respect of:

- key criteria for recognition of an asset; and
- clarification of accounting treatment in respect of initial recognition as an asset and subsequent expenditure, including refurbishment costs.

The policy applies to all of Ergon Energy's business units and legal entities.

Refer to the following Attachments **[EE_1213APRIN_005(A),** AND **EE_1213APRIN_005(B)].**

7. COST ALLOCATION METHOD – STATEMENT OF POLICY(S)

RIN - Schedule 1 paragraph 1.1 (f)

REQUIREMENT

Schedule 1 paragraph 1.1 (f) of the Notice requires Ergon Energy to provide the statement of policy/s for determining the allocation of overheads in accordance with the CAM for the relevant regulatory year and the previous regulatory year:

RESPONSE

Ergon Energy's Statement of Policy is disclosed below, as approved by the Chief Financial Officer. Consideration will be given to incorporating this into Ergon Energy's capitalisation policy when it is next updated.

Statement of Policy – Cost Allocation Method

Ergon Energy complies with the CAM, in accordance with Part F - Cost Allocation, Rule 6.15 Cost Allocation, clause 6.15.1 Duty to comply with Cost Allocation Method of the NER.

Where practical, costs are directly attributed to categories of distribution services and unregulated activities.

Shared costs are causally allocated where support services are provided across the Ergon Energy Group and then allocated in proportion to the direct costs incurred by each Line of Business.

8. MATERIAL DIFFERENCES TO AER DETERMINATION

RIN - Schedule 1 paragraph 1.2, 1.3

REQUIREMENT

Schedule 1 paragraph 1.2 (a)-(d) of the AER's Notice requires Ergon Energy to identify for each of the following items, the material difference between the amounts reported in the Regulatory Accounting Statements and the amounts provided for in the AER FDD for the relevant regulatory year:

- total actual revenue and total forecast revenue;
- total actual Opex and total forecast Opex;
- total actual maintenance expenditure and total forecast maintenance expenditure; and
- total actual Capex and total forecast Capex.

Schedule 1 paragraph 1.3 of the Notice requires Ergon Energy to explain the reasons for any underlying operational activities or drivers that caused each material difference identified in the response to paragraph 1.2.

The AER also requires Ergon Energy to verify specified information, by way of a statutory declaration in accordance with Appendix D to the Notice.

RESPONSE

Please refer to the following explanations for material differences in the Regulatory Accounting Statements in the following Templates:

- Operating Expenditure – Template 10 (Opex), Table 2: Explanation of material difference. See also Table 4-27);
- Maintenance Expenditure – Template 8 (Maintenance), Table 2: Explanation of material differences (see also Table 4-22); and
- Capital Expenditure – Template 5 (Capex), Table 2: Explanation of material differences (see also Table 4-10).

In addition refer to Attachment [**EE_1213APRIN_006]** for supplementary templates prepared for the purposes of providing explanations in material variances between:

- total actual revenue and total forecast revenue.

9. CLASSIFICATION OF DISTRIBUTION SERVICES

RIN - Schedule 1 paragraph 1.4

REQUIREMENT

In respect of the classification of services, Schedule 1 paragraph 1.4 of the Notice requires Ergon Energy to explain the procedures and processes used by Ergon Energy to ensure that the distribution services have been classified as determined in the AER FDD.

RESPONSE

In the majority of instances, the classification of Ergon Energy services happens automatically as customers and retailers generally select the service they require. A listing and description of Ergon Energy services by service order type (with the associated product codes and prices) is provided in the “Price List for ACS” which is published on Ergon Energy’s website. The Price List is developed in accordance with the classification of services (CoS) and Ergon Energy’s AER-approved Pricing Proposal.

Customers can make requests for services through their retailer (if in the market), or they can contact Ergon Energy’s National Contact Centre (NCC). The NCC has a range of scripts and an Online Help System which informs operators about what steps should be taken to correctly identify a service and process a customer’s request. A schedule of rates is also readily accessible to operators to determine on what basis fees will apply for the customer’s requested service (no charge, standard fee, customer-specific quote required etc.).

Tier 2 retailers make requests for Ergon Energy services through market systems in accordance with the National B2B Procedures. Ergon Energy’s Service Transaction Centre manages requests from market retailers, and has well established procedures in place to ensure services are correctly identified and processed appropriately through market systems.

Specialist business units within Ergon Energy have also been established to handle more complex service requests, and calculate prices for services requiring quotations (for example – new connections to the network, supply enhancements, rearrangement of network assets, design and construction of connection assets and street lights etc.). These business units have a range of procedures, work instructions and reference materials to ensure the service is correctly classified and appropriately priced. For example, in the case of large customer connections, Ergon Energy’s Major Customer Connection Group has a manual to assist them to determine the classification of assets, and which components of a project will be required to be funded under the SCS revenue cap, and which components will be funded through ACS charges levied on customers.

Staff requiring further guidance about a service classification, can request specialist regulatory advice from Ergon Energy’s Regulatory Affairs Group.

Customers and retailers also have avenues available to them to request a review of a service classification decision through Ergon Energy’s Tariff Class Assignment and Re-assignment Procedures. These procedures are publicly available in Ergon Energy’s “Information Guide for SCS Pricing”, “Information Guide for ACS Pricing” and “Price List for ACS”. The procedures are also issued to retailers through the ‘Retailers Handbook’.

10. ARRANGEMENTS FOR NEGOTIATED SERVICES

RIN - Schedule 1 paragraph 1.5

REQUIREMENT

Schedule 1 paragraph 1.5 of the Notice requires Ergon Energy to explain the procedures and processes used by Ergon Energy to ensure that the negotiated distribution service criteria, as set out in the AER FDD, have been applied.

RESPONSE

Ergon Energy notes that Schedule 1 paragraph 1.5 of the Draft RIN is not applicable to Ergon Energy during the current regulatory control period.

In its submission to the AER on the Framework and Approach Stage 1 consultation, Ergon Energy did not propose in its classification of services proposal that any of its Distribution Services be classified as Negotiated Distribution Services. As a result, Ergon Energy does not have a Negotiating Framework, nor is the Negotiated Distribution Service Criteria that the AER released on 17 July 2009 relevant.

In accordance with the AER's Queensland Distribution Determination, 2010/11 to 2014/15, Final Decision (May 2009), which accepted the list of services that Ergon Energy identified for each category of Distribution Services, Ergon Energy has no Negotiated Distribution Services.

11. NEGATIVE CHANGE EVENTS

RIN - Schedule 1 paragraph 1.6

REQUIREMENT

Schedule 1 paragraph 1.6 of the Notice requires Ergon Energy to discuss the process it has in place to identify negative change events under NER clause 6.6.1(f) and the threshold of materiality applied by Ergon Energy to these events.

In accordance with Appendix B to the Notice, the AER requires Ergon Energy to verify, by way of a statutory declaration the information provided in response to Schedule 1 paragraph 1.6.

RESPONSE

Process for identifying Negative Change Events

Ergon Energy's process for identifying negative change events involves the following actions:

- Recognising the identification and reporting of negative change events as an additional regulatory obligation within the business. In particular, Regulatory Affairs' work plan has included this as an obligation;
- The identification and reporting of negative change events is coordinated by Ergon Energy's Regulatory Affairs group. However other departments are involved as required;
- Regulatory Affairs is responsible for the identification and communication of the following negative change events: Regulatory Change; Service Standard; and Feed-in Tariff;
- Finance is responsible for the identification of possible negative change events resulting from Tax Changes;
- The relevant departments are responsible for reviewing relevant material, identification of possible negative change events, reporting of events to Regulatory Affairs (as coordinator) and ensuring the timely and accurate documentation of the process;
- The relevant departments are to identify and record the documents/web sites and any other resources intended to be reviewed in the search for negative change events. For example, Queensland government media statements, Commonwealth government media statements, AER publications/statements, financial reporting documents (or other relevant documents providing updates to tax policy);
- A communication protocol is to be established between the relevant departments and Regulatory Affairs and within the Regulatory Affairs department to ensure that the identification process is being actively conducted;
- The responsible person within Regulatory Affairs is required to notify the Regulatory Affairs Manager immediately where a possible negative change event is identified by any department;
- The Regulatory Affairs Manager is to confirm that the event meets the criteria of a negative change event;
- Once confirmed, Regulatory Affairs is to be responsible for the determination of estimated costs associated with the event in conjunction with relevant internal departments;

- In doing so, it is important to consider the distinction between under-expenditure resulting from deliberate business decisions or forecasting error and that resulting from a negative change event. In particular, the distinction between controllable and uncontrollable costs is critical. By nature, a negative change event must be an exogenous event beyond the control of Ergon Energy. By definition, all management decisions by Ergon Energy regarding the investment in and operation of its network that subsequently result in cost savings cannot be treated as a negative pass-through event; and
- Regulatory Affairs is responsible for coordinating the preparation of pass-through applications and providing it to the AER as per requirements.

Materiality Threshold Applicable to Negative Pass through Events

The AER's Determination for Ergon Energy indicates that the AER will apply a materiality threshold to specific nominated events set to the administrative costs of assessing an application[3]. However, for general nominated events the AER Determination did impose a materiality threshold of 1% of the smoothed revenue allowance specified in the Distribution Determination for each of the years of the regulatory control period in which the costs are incurred[4].

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[3] AER (2009), p 299. Note: while this decision was made in the context of the AER's Draft Determination, no changes were proposed in the Distribution Determination (Final Decision).

[4] Ibid, p 312

12. COST ALLOCATION TO THE REGULATED DISTRIBUTION BUSINESS

RIN - Schedule 1 paragraph 2.1-2.3

REQUIREMENT

In respect of cost allocation to the regulated distribution business, Ergon Energy is required to comply with Schedule 1 paragraph 2.1 -2.3 of the Notice, as detailed below.

2.1 Identify each item in the Regulatory Accounting Statement that is:

(a) not allocated on a directly attributable basis but is allocated on a causation basis to the *distribution business*; and

(b) not allocated on a directly attributable basis and cannot be allocated on a causation basis to the *distribution business*.

2.2 For each item identified in the response to paragraph 2.1 (a):

(a) state the amount of the item that has been allocated;

(b) explain the method of allocation and reasons for choosing that method; and

(c) state the numeric amount of the allocator(s) used.

2.3 For each item identified in the response to paragraph 2.1(b):

(a) state its amount;

(b) state whether it was material;

(c) explain the method of allocation and reasons for choosing that method; and

(d) explain the reason(s) why it cannot be allocated on a causation basis.

RESPONSE

Ergon Energy complies with its CAM that has been approved by the AER.

Direct costs are directly attributed to the *distribution* or unregulated businesses.

Shared costs are causally allocated where support services are provided across the Ergon Energy Group. The costs which are causally allocated are disclosed in the Appendix B Regulatory Accounting Statements in Template 15. The method of application is disclosed in Ergon Energy's CAM.

Upon final reconciliation of the shared costs allocated through the overhead allocation process at the end of the regulatory year, it was determined that an amount of $19.6m had been over-recovered. In accordance with Ergon Energy's CAM, this amount was determined to be not material and has not been directly attributed or causally allocated. Ergon Energy's CAM requires such amounts to be allocated to the distribution business.

Ergon Energy has applied further allocations throughout the Regulatory Accounting Statements to enable completion of other Income Statement, Balance Sheet and Cashflow items across the *distribution* and unregulated businesses. The basis for each of these allocations are detailed in the Reasons, Assumptions and Methodology section of this document.

13. COST ALLOCATION TO SERVICE SEGMENTS

RIN - Schedule 1 paragraph 3.1-3.3

REQUIREMENT

Ergon Energy is required to comply with Schedule 1 paragraph 3.1 -3.3 of the Notice, as detailed below.

3.1 Identify each item in the Regulatory Accounting Statements that is:

(a) not allocated on a directly attributable basis but is allocated on a causation basis from the distribution business to a service segment; and

(b) not allocated on a directly attributable basis and cannot be allocated on a causation basis from the distribution business to a service segment.

3.2 For each item identified in the response to paragraph 3.1(a):

(a) state the amount of the item that has been allocated;

(b) explain the method of allocation and reasons for choosing that method; and

(c) state the numeric amount of the allocator(s) used.

3.3 For each item identified in the response to paragraph3.1(b):

(a) state its amount;

(b) state whether it was Material;

(c) explain the method of allocation and reasons for choosing that method; and

(d) explain the reason(s) why it cannot be allocated on a causation basis.

Further it should be noted that service segment refers to SCS, ACS, negotiated services and unregulated services.

RESPONSE

Ergon Energy complies with its CAM approved by the AER.

Direct costs are directly attributed to the categories of Distribution Services and unregulated activities.

Shared costs are causally allocated where support services are provided across the Ergon Energy Group. The costs which are causally allocated are disclosed in the Appendix B Regulatory Accounting Statements in Template 15. The method of application is disclosed in Ergon Energy's CAM.

Upon final reconciliation of the shared costs allocated through the overhead allocation process at the end of the regulatory year, it was determined that an amount of $19.6M had been over-recovered. In accordance with Ergon Energy's CAM, this amount was determined to be not material and has not been directly attributed or causally allocated. Ergon Energy's CAM requires such amounts to be allocated to the SCS.

Ergon Energy has applied further allocations throughout the Regulatory Accounting Statements to enable completion of other Income Statement, Balance Sheet and Cashflow items across the categories of Distribution Services. The bases for each of these allocations are detailed in the Reasons, Assumptions and Methodology section of this document.

14. RELATED PARTY TRANSACTIONS

RIN - Schedule 1 paragraph 4.1-4.3

REQUIREMENT

Schedule 1 paragraph 4.1-4.2 of the Notice requires Ergon Energy to identify each Related Party with which a transaction has been conducted. The Notice also requires Ergon Energy to identify each transaction relating to the provision of SCS, ACS or negotiated distribution services between Ergon Energy and a Related Party, where the transaction amount is greater than five per cent of the relevant total expenditure or revenue category. Relevant categories are SCS revenues, ACS revenues; negotiated distribution services revenues, SCS Capex, ACS Capex, SCS operations expenditure, SCS maintenance expenditure, ACS operations expenditure, ACS maintenance expenditure, negotiated distribution services expenditure.

Further paragraph 4.3 of Schedule 1 of the Notice requires that for each transaction in the response on paragraph 4.2;

- state the name of the Related Party;
- identify any other parties involved;
- explain the nature and purpose of the transaction, including the good(s) or service(s) provided by the Related Party;
- state the actual costs incurred by the Related Party in providing good(s) or services(s), not including any profit margin or management fee incurred by Ergon Energy;
- explain how the actual costs of the good(s) or service(s) incurred was determined;
- identify the actual costs of the good(s) or service(s) in the Regulatory Accounting Statements, including the Asset category, Maintenance Cost category or Operating Cost category to which the actual cost(s) is allocated to; and
- explain the basis upon which the actual costs of the good(s) or service(s) was or were allocated, as identified in the response to paragraph (f), and state the amount of any allocator applied.

RESPONSE

Ergon Energy's related parties are Ergon Energy Telecommunications Pty Ltd which provides telecommunication services and SPARQ Solutions Pty Ltd which provides information technology services. The cost of goods and services provided by these related parties was determined from the invoices issued upon Ergon Energy and were $90.7M for SPARQ Solutions Pty Ltd and $4.4M for Ergon Energy Telecommunications Pty Ltd.

Allocation between entities is established by the methodology as set out in the CAM. Ergon Energy Telecommunications Pty Ltd is treated entirely as an opex and is spread between SCS, ACS and non-regulated activities according to the overhead allocation methodology as set out in the CAM. The costs from SPARQ Solutions Pty Ltd is split between capital and opex using the overhead allocation methodology as set out in the CAM these amount are then split between SCS, ACS and non-regulated again using the CAM methodology.

No other parties are involved.

15. EFFICIENCY BENEFIT SHARING SCHEME

RIN - Schedule 1 paragraph 5.1-5.2

REQUIREMENT

With respect to the Efficiency Benefit Sharing Scheme, Schedule 1 paragraph 5.1 of the Notice requires Ergon Energy to identify all changes between the Capitalisation Policy for the relevant regulatory year and the previous regulatory year. Further, for each change identified in the response to paragraph 5.1, paragraph 5.2 requires Ergon Energy to:

- state, if any, the financial impact of the change;
- state the reasons for the change;
- explain the effect of the change (excluding changes in accounting policies) if any, on:
  - forecast operating and maintenance expenditure incurred for the Relevant Regulatory Year;
  - forecast capex incurred for the Relevant Regulatory Year;
  - actual operating and Maintenance Expenditure incurred for the Relevant Regulatory Year;
  - actual capex incurred for the Relevant Regulatory Year; and
- explain the estimated effect of the change, if any, for the previous regulatory year on:
  - actual operating and maintenance expenditure incurred; and
  - actual capex incurred.

RESPONSE

No Capitalisation Policy changes occurred during the 2012/13 year.

16. DEMAND MANAGEMENT INCENTIVE SCHEME

RIN - Schedule 1 paragraph 6.1

REQUIREMENT

In respect of the DMIA Schedule 1 paragraph 6.1 of the Notice requires Ergon Energy to:

(a) provide an explanation of each DM project or program for which approval is sought;

(b) explain, for each DM project or program identified in the response to paragraph 6.1(a), how it complies with the DM Innovation Allowance criteria detailed at section 3.1.3 of the DMIS, with particular reference to:

- (i) the nature and scope of each demand management project or program;
- (ii) the aims and expectations of each demand management project or program;
- (iii) the process by which each demand management project or program was selected, including the business case for the demand management project and consideration of any alternatives;
- (iv) how each demand management project or program was/is to be implemented;
- (v) the implementation costs of the demand management project or program;
- (vi) any identifiable benefits that have arisen from the demand management project or program, including any off peak or peak demand reductions;

(c) provide an overview of developments in relation to the demand management projects or programs completed in previous years, and any results to date;

(d) state whether the costs associated with each demand management project or program identified in the response to paragraph 6.1(a) are:

- (i) not recoverable under any other jurisdictional incentive scheme;
- (ii) not recoverable under any other Commonwealth or State Government scheme;
- (iii) not included as part of:
  - (1) the forecast Capex or the forecast Opex; or
  - (2) any other incentive scheme applied by the 2010–15 Distribution Determination; and

(e) provide the total amount of the Demand Management Innovation Allowance spent in the previous regulatory year and how this amount has been calculated.

It should be noted that information provide in response to paragraph 6 of Schedule 1 to this Notice will constitute the provision of an annual report for the purpose of paragraph 3.1.4.1 of the AER, Demand Management Incentive Scheme for Energex, Ergon Energy and ETSA Utilities 2010/15, October 2008.

RESPONSE

Please refer to the Demand Management Innovation Allowance Report Attached [**EE_1213APRIN_007].**

17. ASSET REPLACEMENT VOLUMES

RIN - Schedule 1 paragraph 7.1

REQUIREMENT

With respect to the asset replacement volumes reported on template 7 of the workbook attached at Appendix C, the AER requires Ergon Energy to identify the proportion of total replacements that were a like-for-like replacement for each asset, where the new asset provided an equivalent level of service as the asset being replaced. If the proportion of like-for-like replacements is estimated, then Ergon Energy needs to provide details of the basis for the estimation.

RESPONSE

Please refer to responses in the assumptions and methodologies section in respect of the Asset Installation Template 7.

18. STPIS PERFORMANCE MEASURES

RIN - Schedule 1 paragraph 8.1

REQUIREMENT

Schedule 1 paragraph 8.1 of the Notice requires Ergon Energy to explain all Material differences between the target performance measure specified in the STPIS and actual performance reported in the response to paragraph 1.1(b) of Schedule 1.

RESPONSE

Reliability Parameters

Ergon Energy unplanned SAIDI/SAIFI performance are favourable to the End of Year (EoY) STPIS targets for 5 out of 6 STPIS measures. Unplanned LR SAIDI is the only measure marginally unfavourable to the EoY STPIS target.

LR performance for 2012/13 has been reflective of the impact of extremely adverse weather conditions on overall network performance of Ergon Energy. The March quarter was impacted by extended aftermaths of tropical cyclone Oswald and extensive flooding in all of Ergon Energy's southern and most of the central supply regions. Ergon Energy had to take precautionary actions to ensure the safety of its staff and customers while restoring power back to the flood and cyclone affected areas. Tropical cyclone and floods not only impact the performance for the given period but also raise the need for additional inspection and maintenance work. This necessarily has impacted the performance of the network particularly for the LR feeder category which includes a significant proportion of our SWER network.

This is in addition to the effects of the heavy storms in the South West and Wide Bay supply regions on unplanned outage performance on all feeder categories during the December quarter. Bushfire triggered outage events also had had adverse impact on performance for December quarter especially in the Far North and Central supply regions. These are external environmental factors over which Ergon Energy does not have any direct control. The extensive radial nature of the Ergon Energy LR network makes it more susceptible to outage durations (both planned and unplanned).

The extreme weather event days have had a compounding adverse impact on Ergon Energy's network reliability measures across all three feeder categories, especially the outage duration (SAIDI). Ergon Energy has additional challenges specific to outage duration in its rural network because of the vast geographical spread of its predominantly radial network.

The overall customer minutes and customer interruptions due to adverse weather and cyclonic conditions increased by 218% and 34% respectively for this March quarter compared to the same quarter in 2011/12. Customer minutes due to adverse weather for LR feeders only also increased by 242% compared to the same quarter last financial year. A lesser number of LR feeder customers were affected compared to the last storm season by unfavourable weather conditions but were impacted by much longer outage duration due to the floods and lack of safe accessibility of the asset for a quicker restoration.

Ergon Energy has met unplanned STPIS SAIDI/SAIFI targets for both UR and SR feeder categories. Unplanned LR SAIFI is also favourable to the STPIS target. The results are reflective of Ergon Energy's operational and asset management focus on network performance.

Ergon Energy monitors, assesses, analyses and undertakes the necessary remedial action to ensure performance levels that will achieve favourable reliability outcomes. In particular, Ergon Energy has put significant focus on its operational practices to improve the response time to unplanned outages. In addition, Ergon Energy continues to implement many strategies for reliability improvement through its major capital works projects. Specifically, Ergon Energy continues to implement an integrated, whole-of-business Reliability Improvement Plan (includes both operational and asset-focused initiatives) to address network performance requirements for the 2010/15 regulatory control period.

Customer Service Parameters

Ergon Energy's Telephone Answering actual performance was favourable when compared to the target performance with a result of 82.1% against a target of 77.3% of calls answered within 30 seconds. There were a number of factors which impacted on Ergon Energy's ability to answer phone calls within the 30 second requirement throughout the year. In most of the non-storm season months the smaller volume of calls enabled the call centre to handle calls well above the target rate. This was due to fewer weather and natural disaster events during this part of the year. This is reflected in the number of days per month where 77.3% was not achieved. In July and August 2012 and in April, May and June 2013 there were 5 or fewer days in each of these months where the target was not met.

There were, however a number of events during the year that had a considerable impact on the call centres ability to answer calls within the target timeframe. In late September there was a significant outage in Charters Towers caused by a faulty transformer which lasted for several days which triggered additional calls. During the December quarter the number of loss of supply and emergency calls almost doubled when compared to the October quarter. Primary causes for these additional calls during this quarter included impacts from bush fires in the Far North and Central supply regions as well as considerable storm activity which hit the South West and Wide Bay regions. In the March quarter we saw the impact of Cyclone Oswald and its associated weather systems which travelled down the length of Queensland. This caused considerable flooding and damage to Ergon Energy's network and assets. This lead to a 48% increase in calls for the March quarter compared to the same quarter in the previous year. There was also an increase of 82,583 calls compared to the December quarter of 2012/13. Whilst there was an MED declared between 24th January and the 28th January 2013, the number of days that the weather system caused issues with the network fell outside of this exclusion period. During these busier times the number of available staff rostered was maximised with all faults and emergency trained staff having these calls handled at a higher priority than other call types.

Despite these challenges the contact centre was able to achieve a year to date performance result of 78.0% by the end of January. From January through the remainder of the financial year there were no significant incidents that threatened the contact centres ability to meet this performance target which ultimately lead to the final result of 82.1% being achieved.

19. RECONCILIATION OF REGULATED ASSET BASE

RIN - Schedule 1 paragraph 9.1

REQUIREMENT

With respect to Reconciliation of RAB Schedule 1 paragraph 9.1 of the Notice requires Ergon Energy to provide information that reconciles the incremental change in Property, Plant and Equipment category within the Audited Statutory Accounts; and the incremental change in the closing values for the RAB between the previous regulatory year and the relevant regulatory year.

RESPONSE

Ergon Energy provides a reconciliation of its RAB as an Attachment [**EE_1213APRIN_008].**

20. GROUP CORPORATE AND ORGANISATIONAL STRUCTURES

RIN - Schedule 1 paragraph 10.1

REQUIREMENT

In respect of Charts Schedule 1 paragraph 10.1 of the Notice requires Ergon Energy to provide charts that set out the group corporate structure of which Ergon Energy is a part and the organisational structure for Ergon Energy.

RESPONSE

Figure 1 illustrates Ergon Energy's Group Structure. The Ergon Energy Group comprises a series of companies involved in the purchase, distribution and sale of electricity in Queensland, both within and outside the NEM.

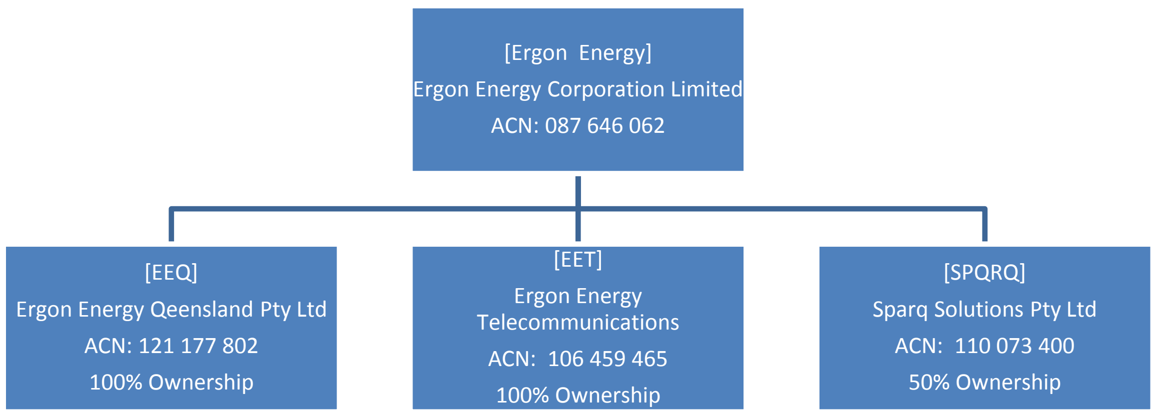

Figure 1: Ergon Energy Group Structure

Figure 2 illustrates Ergon Energy's organisation structure. In particular, it shows the relationship between the Board of Directors, the Executive Management Team, and the various Business Units within Ergon Energy.

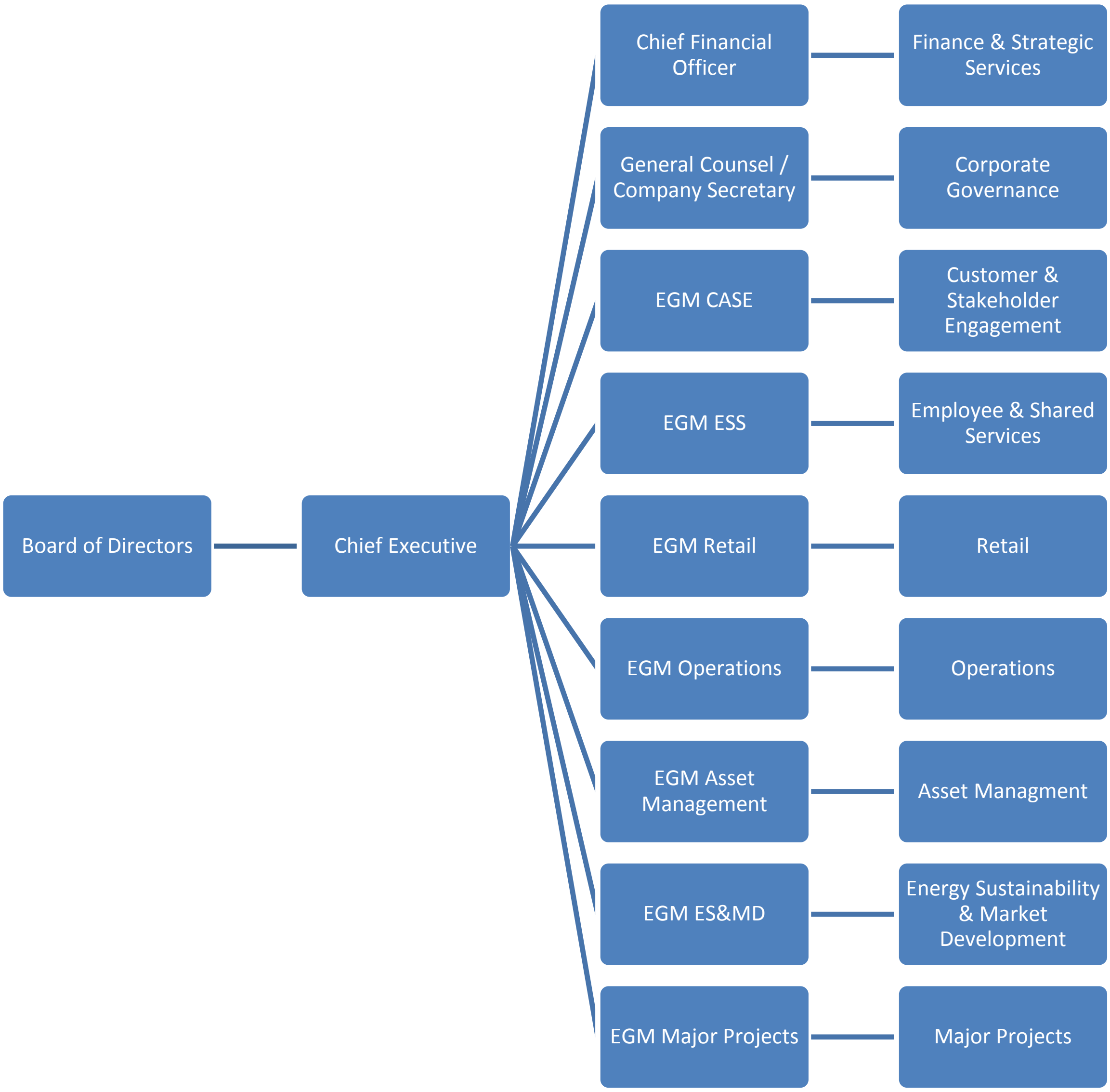

Figure 2: Ergon Energy Organisational Chart

21. AUDIT REPORTS

RIN - Schedule 1 paragraph 11.1, Appendix E

REQUIREMENT

Schedule 1 paragraph 11.1 of the Notice requires Ergon Energy to provide the results of the audit as specified in Appendix E to the Notice, namely the audit report/s in the form of:

- a Special Purpose Financial Report in accordance with the requirements set out at Appendix E of the Notice; and
- Audit Report/s (for Non-Financial Regulatory Templates information) in accordance with the requirements set out at Appendix E of the Notice.

RESPONSE

Ergon Energy notes the following auditors were appointed to audit it's 2012/13 Annual Performance RIN and associated templates (as appropriate):

- Auditor-General of Queensland to audit the Regulatory Accounting Statements in accordance with the Audit scope at Appendix E paragraph 1.1(a) of the RIN;
- Parsons Brinckerhoff (PB) to audit the Non-Financial Regulatory Templates in accordance with the Audit scope at Appendix E paragraph 1.1(b) of the RIN.

As required under Schedule 1 paragraph 11.1 of the Notice, Ergon Energy provides the following as attachments to this report, being the results of the abovementioned audits, namely the audit reports:

- Parsons Brinckerhoff (PB) Audit Report [**EE_1213APRIN_009; and**
- Queensland Audit Office – Audit Opinion [**EE_1213APRIN_010**].

Clarification was sought from the AER on 14 February 2013 on whether forecast demand data (Template 2 Appendix C) should have been outside of audit scope. The AER confirmed this information was not intended to be subject to audit, and advised if Ergon Energy chose to exclude the information from audit, no compliance action would be taken by the AER in respect of this aspect of the response. Ergon Energy excluded forecast demand data from the scope of Parson Brinkerhoff's audit.

22. BOARD RESOLUTION

RIN - Schedule 1 paragraph 12

REQUIREMENT

Schedule 1 paragraph 12.1 of the Notice requires Ergon Energy to provide an extract from the Board minutes or a resolution agreed to at an Ergon Energy Board meeting that confirms that, to the best of the Board's information, knowledge and belief:

- the information provided in the response to paragraph 1.1(a) (being the information to be provided in the workbook attached at Appendix B) is true and fair; and
- the STPIS, demand and asset installation information provided in the response to paragraph 1.1(b) (being the information to be provided in templates 1(a), 1(b), 1(c), 1(d), 1(e), 1(f), 1(g) and 2 and 7 of the workbook attached at Appendix C) is true and fair.

RESPONSE

Ergon Energy herein provides a copy of the resolution made by the EECL Board, as an attachment [**EE_1213APRIN_011**].

Further to clarification sought from the AER on the 14 February 2013, Ergon Energy has excluded the information in Appendix B – Regulatory Accounting Statements and Appendix C – Non-Financial Regulatory Templates which is subject to Statutory Declaration. This is based on confirmation from the AER that the requirement for Board Resolution is for information which is subject to Independent Audit only. More specifically, the Board Resolution excludes information at par 1.1(a)-(b) of Appendix E - Audits, being:

Regulatory Accounting Statements:

i. Audited Statutory Accounts;
ii. forecast information including step change expenditure in relation to the Efficiency & Effectiveness Program as set out in template 13 and deferred capital costs as set out in table 6 in template 10;
iii. Non-financial data; and
iv. Explanations relating to Material differences and step change expenditure.

Non-Financial Regulatory Templates:

i. information provided in response to template 1(d) STPIS MED threshold, that has previously been subject to audit and submitted to the AER; and
ii. information provided in response to template 7 Asset installation, for the 2012/13 regulatory year.

As advised, Ergon Energy understands compliance action by the AER will not be taken in respect of this aspect of its response.

23. STATUTORY DECLARATION

RIN - Appendix D

REQUIREMENT

The AER requires Ergon Energy to verify specified information, by way of a statutory declaration by an Officer of the Company in accordance with Appendix D to the Notice. A pro forma Statutory Declaration was provided by the AER in this regard.

RESPONSE

Ergon Energy provides a statutory declaration signed by the Chief Executive of EECL, as an attachment [**EE_1213APRIN_012**].

24. APPENDIX A – LIST OF ATTACHMENTS

Unless otherwise identified as confidential information, the below attachments are for Public release.

Title	Attachment
EE_1213APRIN_001	Ergon Energy's 2012/13 Regulatory Accounting Statements, for the regulatory year ended 30 June 2013
EE_1213APRIN_002	Ergon Energy's 2012/13 Non-Financial Regulatory Templates, for the regulatory year ended 30 June 2013
EE_1213APRIN_003	Cost of Debt (Attachments A-D)
EE_1213APRIN_004	Reconciliation of Audited Statutory Accounts and Regulatory Accounting Statements
EE_1213APRIN_005(a) **EE_1213APRIN_005(b)**	Capitalisation Policies; Property, plant and equipment; and Intangible Assets
EE_1213APRIN_006	Supplementary Templates; Explanations for material variances
EE_1213APRIN_007	Ergon Energy's 2012/13 Demand Management Innovation Allowance - Annual Report to the AER, for the regulatory year ended 30 June 2013
EE_1213APRIN_008	Reconciliation of Regulatory Asset Base
EE_1213APRIN_009	Parsons Brinckerhoff - Audit Report (Non-Financial Regulatory Templates)
EE_1213APRIN_010	Queensland Audit Office - Audit Opinion (Regulatory Accounting Statements)
EE_1213APRIN_011	Ergon Energy Corporation Limited, Board Resolution
EE_1213APRIN_012	Ergon Energy Corporation Limited, Chief Executive - Statutory Declaration

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24 hours a day, 7 days a week

Life-Threatening Emergencies Only
Triple zero (000) or 13 16 70
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Ergon Energy Corporation Limited ABN 50 087 646 062
Ergon Energy Queensland Pty Ltd ABN 11 121 177 802

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