Category Analysis
RIN – Basis for Preparation

CONFIDENTIAL

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Category Analysis Regulatory Information Notice Basis of Preparation

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1. Introduction

As per the AER letter dated the 07th March 2014, a Regulatory Information Notice has been issued under section Division 4 of Part 3 of the National Electricity (Victoria) Law to United Energy.

The Notice requires United Energy to provide, 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 a function or power conferred on it under the NEL or the *National Electricity Rules* (**NER**), namely:

(a) to publish network service provider performance reports (annual benchmarking reports) the purpose of which are to describe, in reasonably plain language, the relative efficiency of each Distribution Network Service Provider in providing direct control services over a 12 month period

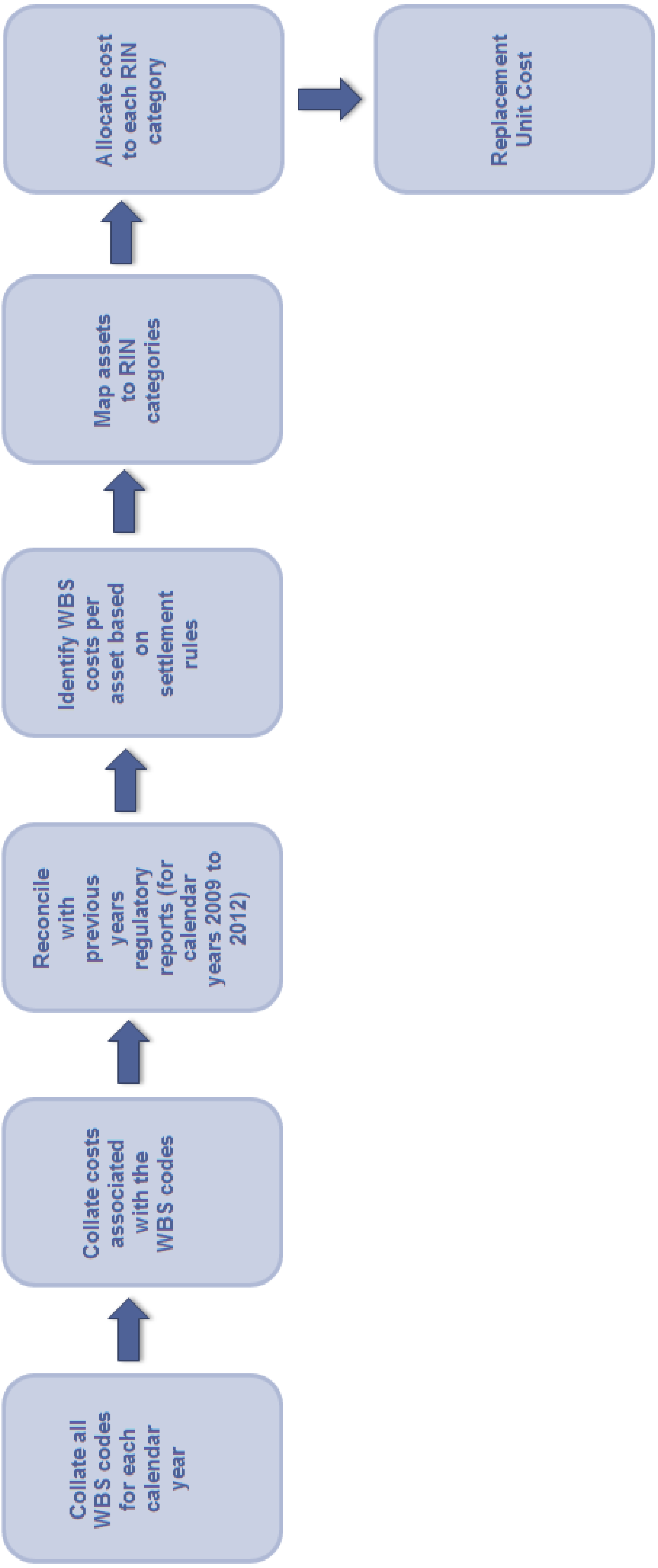
(b) to assess benchmark operating expenditure and benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider relevant to building block determinations

This document , “United Energy Category Analysis RIN – Basis of Preparation”, has been compiled in accordance with the requirements specified.

2. Repex

2.1. Replacement Expenditure

The flow diagram below illustrates the process to collate the annual REPEX data required for the Category Analysis Benchmarking RIN.


Collate all WBS codes for each calendar year
Collate costs associated with the WBS codes
Reconcile with previous years regulatory reports (for calendar years 2009 to 2012)
Identify WBS costs per asset based on settlement rules
Map assets to RIN categories
Allocate cost to each RIN category
Replacement Unit Cost

UE then collate all asset replacement costs from previously submitted annual regulatory reports for the calendar years 2009 to 2013 based on the MAT codes which start with R.

Compare the costs of each MAT code obtained from the SAP system with the cost in the submitted regulatory annual reports. If a variance was identified between the two sources, further investigation were conducted by using Excel lookup techniques to identify the work orders responsible for the variance and reconcile the work orders, or seeking advice from UE SAP subject matter expert to determine reasons for variants such as incorrect settlement of costs.

For 2009 and 2010 an entry was taken up in the ledgers to account for adjustments to contractors for prior periods. In other words the adjustment does not relate to the REPEX expenditure these year. These payments are a reconciling amount between annual RINS and the capex reported in this RIN. The RIN is used to calculate REPEX costs for the period 2009 to 2013 and prior period adjustments taken up in 2009 and 2010 are not relevant when benchmarking expenditure for the RIN period.

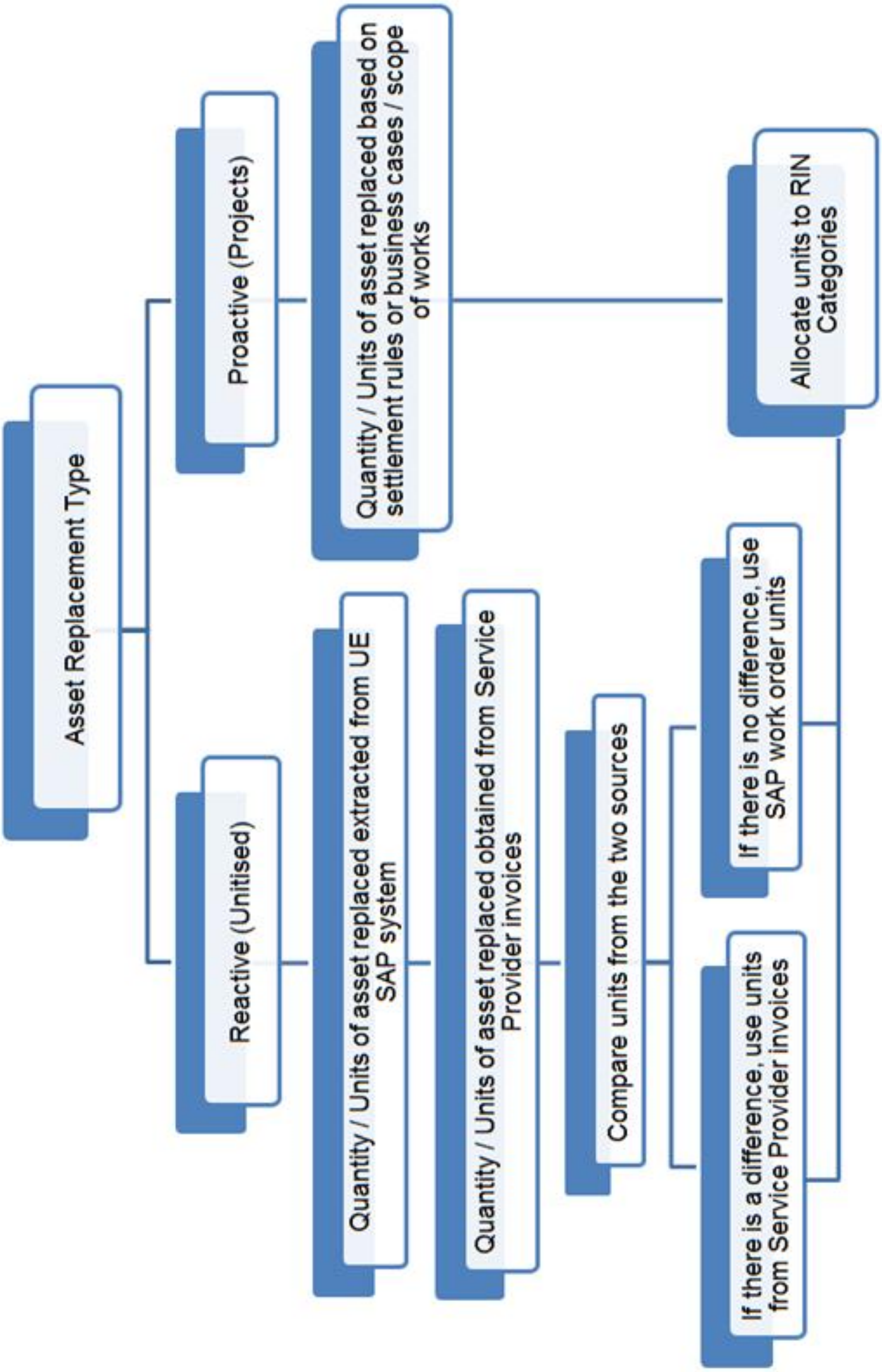
Whilst the total REPEX has been reverted to SAP, allocations have taken place between late June, therefore UE considers the data to be estimated.

2.2. Replacement Units

The following are the three main steps to collate the annual asset replacement units required for the Table 2.2.1 of the Category Analysis Benchmarking RIN and the DNSP Annual Non-Financial templates:

1. Determine asset replacement category (i.e. unitised or projects)
2. Determine the asset replacement units / quantities based on asset replacement category
3. Allocate the asset replacement units to a RIN category

These steps are illustrated in the flow diagram below.


Asset Replacement Type
Reactive (Unitised)
Proactive (Projects)
Quantity / Units of asset replaced extracted from UE SAP system
Quantity / Units of asset replaced obtained from Service Provider invoices
Compare units from the two sources
If there is a difference, use units from Service Provider invoices
If there is no difference, use SAP work order units
Quantity / Units of asset replaced based on settlement rules or business cases / scope of works
Allocate units to RIN Categories

UE has two types of asset replacement categories (i.e. unitised and projects) which require two different processes to obtain the asset replacement units.

There is a field in SAP that categorises a WBS code as a Unitised replacement or Projects replacement. Collate all the Unitised replacement WBS codes into an Excel spreadsheet and all the Projects replacement WBS codes into another Excel spreadsheet.

There are two separate methods to obtain the Service Provider unitised work volumes depending on the period the works were undertaken. One method was employed for calendar years 2009 – 2011 and another method for calendar years 2012 onwards. This was due to UE transitioning the Service Provider Agreement from OSA to OMSA on 1st July 2011. From July to Nov 2011, prior to the new UE SAP ERP being implemented, workarounds were required to manage the OMSA contract in the SAP 4.6C system.

This required additional reporting to be conducted outside of the SAP 4.6C system.

2.2.1. Replacement asset failures

AER's Asset Failure (Repex) definition is:

The failure of an asset to perform its intended function safely and in compliance with jurisdictional regulations, not as a result of external impacts such as:

- *extreme or atypical weather events; or*
- *third party interference, such as traffic accidents and vandalism; or*
- *wildlife interference, but only where the wildlife interference directly, clearly and unambiguously influenced asset performance; or*
- *vegetation interference, but only where the vegetation interference directly, clearly and unambiguously influenced asset performance.*

Excludes planned interruptions.

A 'Conditional' failure is when an asset has exceeded its minimum technical specification (for example a pole inspection reveals residual strength is less than the specified).

A 'Functional' failure is the inability of an asset to fulfil one or more intended function(s) to a standard of performance which is acceptable to the user of the asset. (for example when a pole physically fails i.e. falls down).

AER considers 'conditional' failure rates will be biased by individual Network Service Providers (NSPs) specific criteria, which is susceptible to policy changes across time. For this reason, NSPs must report on functional failures.

Therefore asset failure will denote functional failures only.

In order to extract asset failures for functional failures only, asset failures were extracted from the following two sources:

- Distribution Management System (DMS) / Outage Management System (OMS)
- Asset Lifecycle Management Plans

The table below tabulates the source of the asset failure data for each asset type.

Asset Type	Source
Poles, Pole Top Structure, Overhead conductors, Cables, Pits & Pillars, Distribution Transformers, Services, Surge Arresters, HV & LV switchgear	DMS / OMS
Zone Substation Transformers, Zone Substation Circuit Breaker, Protection Relays	Asset Lifecycle Management Plans
Public lighting pole & luminaires	Replacement quantities

Refer excel template for the split between actual and estimated data.

2.3. Selected asset characteristics

Assets have been allocated to Urban/short rural based on the percentages of feeders allocated to those categories as at 2013. Noting that UE does not have any CBD or long rural areas. For overhead conductors where the cable has been allocated buy material type rather than location – this data has been extracted from GIS.

Given the same percentage has been applied to all asset clauses this data is considered to be estimated.

3. Augex Project Data

The augmentation expenditure section of the CA RIN on sheet 2.3 is divided into four tables outlining the projects completed during the period and those that are currently in-flight that have had expenditure incurred in the period. The tables relate to categorised network levels with the projects listed or aggregated under the relevant classification. The tables included within the template are:

- Table 2.3.1 – Augex data – Sub-transmission substations, switching stations and zone substations
- Table 2.3.2 – Augex data – Sub-transmission lines
- Table 2.3.3 – Augex data – HV feeders, Distribution substations and LV feeders
- Table 2.3.4 – Augex data – Total Expenditure

UE is likely to have completed and have in-flight projects, for every table classification outlined in the CA RIN template. Therefore all tables need to be populated in order to accurately complete the template for submission. The AER has defined materiality thresholds for including projects. UE has elected to include all projects because applying the materiality threshold would result in some tables remaining empty.

All augmentation (reinforcement) projects are classified by UE as “Demand” projects and therefore this will be the only subcategory required to populate this section of the CA RIN.

The mapping of the UE project codes into the CA RIN tables are:

- DZ Zone Substation Projects (map to Table 2.3.1 and 2.3.4)
- DO Sub-transmission Projects (map to Table 2.3.2 and 2.3.4)
- DS HV Feeder, Distribution Substation and LV Projects (map to Table 2.3.3 and 2.3.4)
- DL Power Factor Correction Projects (map to “Other Assets” in Table 2.3.4) since they are pole-top HV capacitors
- GP Land related expenditure (map to the land and easement columns of the CA RIN)

3.1. Augex asset data – subtransmission substations, switching stations and zone substations

The method to populate the required data for all fields is outlined below.

- **Substation ID**

There are two primary pieces of information stored in this field:

  - Substation ID prefix followed by
  - Project Description text

Both of these pieces of information can be obtained using the "AMP Project List", filtering the list for zone substation projects.

- **Substation Type**

The substation type is invariably 'Zone Substation' for UE; the classification should be made based on the substation ID. Of Sub-transmission Substations, Switching Stations and Zone Substations, UE only has Zone Substations in its network.

- **Project ID**

The project ID is the SAP Project code, this ID can be found using any of the following methods:

  - From the CAPEX Works Program Project Reconciliation spread-sheet
  - From the Request for Statement of Works (RSOW) in the project folde
  - Searching SAP using the project builder (CJ20N) to return the code for the project description
  - Use the financial report to link the SAP code (WBS with no sub) to the description
  - Using the Project Lists to populate from the relative field

Sometimes multiple project IDs exist, particularly those projects that were in-flight during the UE hand-back from Jemena. Where this is the case, all project IDs are listed. Where the project ID commences with AAM, they are recorded in Alinta SAP 4.6c. Where a project ID commences with UED, they are recorded in UE SAP ISU.

- **Project Type**

The project type should be selected by review of the Project Description or the business case and scope of the project located in the project folders. It reflects the main type of work undertaken for the project.

- **Project Trigger**

The project trigger should also be selected based on the business case and scope of the project. Most commonly the project is based on demand growth, as all augmentations are planned and carried out based on demand. However some are classified as voltage, fault level or reactive power issues therefore the decision should be made based on each project from the documentation in the project directory. The project trigger reflects the need for the project.

Where the project trigger is defined as "other", the project may be related to a change triggered by works in the transmission network.

- **Voltage (kV)**

The voltage on the primary/secondary side of the substation, this can be found knowing the substation ID. Mostly this will be 66/22 or 66/11 with the exception of the 22/11 and 22/6.6 zone substations (BW and SH).

Where no primary side voltage is provided, the works are entirely undertaken on the secondary side of the transformation in the substation.

- **Substation Ratings (Pre and Post, Normal and Emergency)**

The substation ratings can be completed using the Load Forecast Manual. Each zone substation is listed with the ratings both past and planned, the 'normal cyclic rating' is the summer (N) cyclic rating and the '(N-1) emergency rating' is the summer (N-1) 2hr emergency rating in the Manual. The change in rating will be recorded for the year of the project, this allows for the population of pre and post for these fields. The values can be cross-checked against the business case for the project if there is some uncertainty in the data. Where the value is N/A, the project is unrelated to a capacity augmentation and therefore there is no change in the station ratings.

"Normal Conditions" is defined as the state of the network when all items of plant are in service (i.e. no network abnormalities).

- **Transformers (Units, MVA Added, Expenditure)**

The transformers field is completed using the project scope of work documentation; the number of transformers added is clearly described in the business case and scope. The 'MVA added' column relates to the rating of the transformer added. UE uses 20/33MVA (ONAN/ODAF) transformers for all its new transformer purchases except for 22kV sub-transmission zone substations. Where 12/20 is specified, this is likely to be a relocatable transformer (hot-spare).

The MVA added column reflects the summated nameplate rating of all transformers added. Where it is N/A there were no transformers added.

"Normal Conditions" is defined as the state of the network when all items of plant are in service (i.e. no network abnormalities).

The expenditure column is provided from the project cost breakdown information provided by Service Delivery.

The transformer expenditure column was completed using the project statement of works (cost breakdown) and business case. For some projects where the business case values stated total FIM (free issue material) value only, transformer breakdown was taken from either the independent estimate documents (where available) or identifying purchase order line items relevant to transformer material cost in SAP. In case where SAP line items were not defined, a cost assumption was made between materials and total FIM value. For more recent projects, the cost breakdown was requested from service providers. A 60-40% split of FIM was assumed respectively for projects where 1 transformer and 1 switchboard were procured.

- **Switchgear (Units Added, Expenditure)**

The units of switchgear added during a substation project need to be added manually from the description in the detailed scope of work or business case. The AER requests that this include all switching equipment including:

  - Circuit Breakers

- o Isolators
- o Switches

The equipment can be automated or manual; all must be included in the template. Where switches/isolators are integrated into a single unit (eg. disconnector switch with integrated earth switch), then UE has assumed that this is one unit. The settlement rules can be used to verify the number of units added particularly for the newer projects. The expenditure column is provided from the project cost breakdown information provided by Service Delivery.

The expenditure column for switchboard was completed using the project statement of works and business case. For some projects where the business case values stated total FIM (free issue material) value only, Switchboard breakdown was taken from either the independent estimate documents (where available) or identifying purchase order line items relevant to transformer material cost in SAP. In case where SAP line items were not defined, a cost assumption was made between materials and total FIM value. For more recent projects, the cost breakdown was requested from service providers. For any other projects, a 60-40% split of FIM was assumed respectively for projects where 1 transformer and 1 switchboard were procured.

- **Capacitors (MVAr Added, Expenditure)**

The capacitors added as part of a project can be recorded through either the project directory (business case or detailed scope of works) or in the Load Forecast Manual as mentioned previously. The added capacitors need to be entered into the template in terms of MVAr added. The Load Forecast Manual breaks down the added capacitors into zone substation capacitor banks and feeder line (pole-top) capacitors. Given pole-top capacitors are not installed inside zone substations (DL code rather than DZ), they are not captured here, but included in the “Other Asset” category of Table 2.3.4.

- **Installation (Labour) (Volume, Expenditure)**

The volume and expenditure columns are provided from the project cost breakdown information provided by Service Delivery.

The labour component of expenditure was sourced from SAP.

- **Other Expenditure (Civil, Contracts, Other Direct)**

The expenditure columns are provided from the project cost breakdown information provided by Service Delivery.

Civil and other contract expenditures were sourced SAP.

Since SAP doesn’t record civil subcontracts expenditure as a separate cost allocation, the civil cost was manually separated by identifying line items associated with civil contracts. These values were calculated for each project and subtracted from total subcontract value. In case where SAP line items were not described, the information was requested from service providers.

Other direct expenditures were sourced from SAP using CJ74 transaction with relevant cost elements.

- **Years Incurred**

The number of years for which the project expenditure was divided, this allows for only one entry per project as all stages should be consolidated and any combinations displayed under this heading. Where expenditure spans multiple calendar year, a range of years is provided.

- **All Related Party (Margins, Total)**

The expenditure columns are provided from the project cost breakdown information provided by Service Delivery.

Related Party (Margins) was sourced from SAP.

- **All Non-Related Party (Contracts)**

The expenditure column is provided from the project cost breakdown information provided by Service Delivery.

Related Party (Margins) was sourced from SAP.

- **Land and Easements**

Land and easement costs associated with each project are obtained from SAP project IDs with activity classifications “GP”. Land purchase expenditures are costs associated with the purchase of land for a future zone substation or an expansion of a zone substation. Easement expenditures are costs associated with compensating land owners for easement acquisition.

- **Total Expenditure**

Although a column is not provided in the CA RIN, the summation of all expenditure columns (barring the land and easement expenditure) should tally the total cost of the project. To verify and reconcile the costs, this summated cost has been compared with the total project cost in SAP as recorded in the regulatory accounts, the business case value and the budgeted value.

- **Comments**

Although a column is not provided in the CA RIN for comments UE has recorded for each project in the CA RIN, the budget, business case value, commission year and the project COWP tracking ID, all of which is available in the “AMP Project List”. This extra information helps to completely define the project.

- **Related projects**

  Some of the projects involved more than one data category (zone substation, sub-transmission and feeder) and reported them in the template accordingly. Such projects and their relationships are summarised below.

Project	Data category		
	Zone substation	Sub-transmission	Feeder
CDA 2nd transformer (mobile)	Yes	N/A	Yes
LD third transformer	Yes	N/A	Yes
LWN New 66/22kV zone substation in Langwarrin and property acquisition	Yes	Yes	Yes
M 3rd transformer	Yes	N/A	Yes
MTN Convert into a fully switched station (MTN redevelopment)	Yes	N/A	Yes
RBD Convert RBD into a fully switched station (RBD redevelopment)	Yes	N/A	Yes

3.2. Augex asset data – subtransmission lines

The method to populate the required data for all fields is outlined below.

- **Line ID**

There are two primary pieces of information stored in this field:

  - Line (from) – Line (to) ID prefix followed by
  - Project Description text

Both of these pieces of information can be obtained using the AMP Project List, filtering the list for sub-transmission projects.

If a project involves an upgrade of two or more lines, then the project details in the RIN needs to be apportioned into individual lines to satisfy the regulatory reporting requirement.

Where a Line (to) is not specified, the sub-transmission works are conducted at the Line (from) substation.

- **Project ID**

The project ID is the SAP Project code, this ID can be found using any of the following methods:

  - From the CAPEX Works Program Project Reconciliation spread-sheet

- From the Request for Statement of Works (RSOW) in the project folders
- Searching SAP using the project builder (CJ20N) to return the code for the project description
- Use the financial report to link the SAP code (WBS with no sub) to the description
- Using the Project Lists to populate from the relative field

Sometimes multiple project IDs exist, particularly those projects that were in-flight during the UE hand-back from Jemena. Where this is the case, all project IDs are listed. Where the project ID commences with AAM, they are recorded in Alinta SAP 4.6c. Where a project ID commences with UED, they are recorded in UE SAP ISU.

- **Project Type**

The project type should be chosen based on the scope or business case information for the project. The choices need to be selected from the project type dropdown list in the template. It reflects the main type of work undertaken for the project.

Where the project type is defined as "other", the project may be related to a change triggered by works in the transmission network or another distributor.

The details of the projects that are categorised as **"Other – specify"** in the project type, are summarised below.

Project	Description
ERTS 66kV line works associated with 4th ERTS transformer	This project was to re-arrange 66kV sub-transmission lines owned by UE at ERTS to facilitate 4th transformer project.
MTN No. 2 Feeder realignment at TBTS (works associated with 3rd TBTS transformer)	This project was to re-arrange 66kV MTN #2 sub-transmission line at TBTS to facilitate 3rd transformer project.
SVTS-RD Upgrade (UE input to CitiPower project)	This project was to facilitate upgrading of SVTS-RD leg of the SVTS-EB-RD-SVTS 66 kV loop. The SVTS-RD leg owned by CitiPower.
RTS 66kV Line Works associated with RTS redevelopment	This project was to re-align 66kV sub-transmission lines owned by UE at RTS to facilitate the station redevelopment.

- **Project Trigger**

The project trigger is almost invariably 'Demand growth' as the table is to be populated using demand type projects. However some demand projects can still be triggered by other factors, therefore the business case and scope need to be referenced in order to ascertain the correct trigger for the project.

In addition to the primary triggers specified in the template, consideration is given to the secondary triggers such as inadequate operational flexibility, insufficient load transfer capability and poor reliability performance for these projects.

The details of the project that is categorised as "Other – specify" in the project trigger, are summarised below.

Project	Description
RTS 66kV Line Works associated with RTS redevelopment	This project was to re-arrange 66kV sub-transmission lines owned by UE at RTS to facilitate SPAusNet's terminal station redevelopment.

- **Voltage (kV)**

Sub-transmission lines in the UE network except some lines ex MTS are 66kV; therefore this will be the entry for all lines aside from those going to SH or BW which are 22kV.

- **Route Line Length Added**

This is the length of line added in kilometres for the project, for instance a new line would have the full length in this field whereas a reconductor or re-tensioned (thermal uprate) project would have zero. This must be drawn from the detailed scope for the project. Line removal (if applicable in the project) is not considered at all in the CA RIN.

- **Poles/Towers (Added, Upgraded, Expenditure)**

The number of poles/towers added or upgraded needs to be included separately and must be drawn from the Service Provider Statement of Work (usually an attachment) or the project detailed scope of works. The settlement rules can be used to verify the number of poles/towers added/upgraded.

All modifications to a pole/tower are considered an upgrade.

The number of poles/towers can be found from one of the following sources.

- Detailed scope of works or statement of works.
- Settlement rules in SAP. It includes new, abolish and improve categorisation for each asset within a given WBS.
- Construction drawings.
- GIS (iView). By checking the installed date for the poles in the relevant section.

The expenditure column is provided from the project cost breakdown information provided by Service Delivery and includes civil costs.

The expenditure for Poles/tower was sourced from project cost breakdown or independent estimator documentations. In case where this information was not available, pole/tower cost was estimated by calculating line items with relevant descriptions in SAP.

- **Overhead Lines (Added, Upgraded, Expenditure)**

The “added” field is the length of overhead line added in kilometres for the project, for instance a new overhead line would have the full length in this field.

The “upgraded” field is the length of overhead line reconductored or re-tensioned (thermal uprate). Line removal (if applicable in the project) is not considered at all in the CA RIN.

This information is available in the project detailed scope of work or statement of works and needs to be manually added for each length added or modified. This information can sometimes be found on settlement rules in SAP too for validation.

The expenditure column is provided from the project cost breakdown information from SAP..

The expenditure for overhead lines was sourced from project cost breakdown or independent estimator documentations. In case where this information was not available, cost was estimated by calculating line items with relevant descriptions in SAP.

- **Underground Cables (Added, Upgraded, Expenditure)**

The “added” field is the length of underground cable added in kilometres for the project, for instance a new underground cable would have the full length in this field. The “upgraded” field is the length of underground cable replaced with a larger rated cable or bentonited
(thermal uprate).

Cable removal (if applicable in the project) is not considered at all in the CA RIN.
This information is available in the project detailed scope of work or statement of works and needs to be manually added for each length added or modified. This information can sometimes be found on settlement rules in SAP too for validation.

The expenditure column is provided from the project cost breakdown information from SAP.

The expenditure for underground lines was sourced from project cost breakdown or independent estimator documentations. In case where this information was not available, cost was estimated by calculating line items with relevant descriptions in SAP.

- **Other Plant (Expenditure)**

These are costs associated with materials that are not classified into the above categories.

The expenditure columns are provided from the project cost breakdown information provided by Service Delivery.

Other plant item expenditure was calculated by subtracting total pole/tower, overhead and underground lines cost from total material expense in SAP.

- **Installation (Labour) (Volume, Expenditure)**

The volume and expenditure columns are provided from the project cost breakdown information provided by Service Delivery.

The labour component of expenditure was sourced from SAP.

- **Other Expenditure (Civil, Other Direct)**

The expenditure columns are provided from the project cost breakdown information from SAP.

Since SAP doesn't record civil subcontracts expenditure as a separate cost allocation, the civil cost was manually separated by identifying line items associated with civil contracts. These values were calculated for each project and subtracted from total subcontract value. In case where SAP line items were not described, the information was requested from service providers.

Other direct expenditures were sourced from SAP.

- **Total Direct Expenditure**

This is a formulated cell which does not need to be completed; it should not be typed over.

- **Years Incurred**

The number of years for which the project expenditure was divided, this allows for only one entry per project as all stages should be consolidated and any combinations displayed under this heading. Where expenditure spans multiple calendar year, a range of years is provided.

- **All Related Party (Margins, Total)**

The expenditure columns are provided from the project cost breakdown information from SAP.

Related Party (Margins) was sourced from SAP.

- **All Non-Related Party (Contracts)**

The expenditure column is provided from the project cost breakdown information from SAP.

Related Party (Margins) was sourced from SAP.

- **Land and Easements**

Land and easement costs associated with each project are obtained from SAP project IDs with activity classifications "GP". Land purchase expenditures are costs associated with the purchase of land for a new line or an upgrade of an existing line. Easement expenditures are costs associated with compensating land owners for easement acquisition.

- **Total Expenditure**

Although a column is not provided in the CA RIN, the summation of all expenditure columns (barring the land and easement expenditure) should tally the total cost of the project. To verify and reconcile the costs, this summated cost has been compared with the total project cost in SAP as recorded in the regulatory accounts, the business case value and the budgeted value.

- **Comments**

Although a column is not provided in the CA RIN for comments UE has recorded for each project in the CA RIN, the budget, business case value, commission year and the project COWP tracking ID, all of which is available in the "AMP Project List". This extra information helps to completely define the project.

- **Related projects**

Some of the projects involved more than one data category (zone substation, sub-transmission and feeder) and reported them in the template accordingly. Such projects and their relationships are summarised below.

Project	Data category		
	Zone substation	Sub-transmission	Feeder
LWN New zone substation subtransmission lines works	Yes	Yes	Yes

3.3. Augex data – HV/LV feeders and distribution substations

- Project Type

There are two primary pieces of information stored in this field:

  - Feeder ID prefix followed by
  - Project Description text

Both of these pieces of information can be obtained using the AMP Project List, filtering the list for HV feeder projects.

- Poles/Towers (Added, Upgraded)

The number of poles/towers added or upgraded needs to be included separately and must be drawn from the Service Provider Statement of Work (usually an attachment) or the project detailed scope of works. The settlement rules can be used to verify the number of poles/towers added/upgraded.

All modifications to a pole/tower are considered an upgrade.

The number of poles/towers can be found from one of the following sources.

  - Detailed scope of works, statement of works or business case.
  - Settlement rules in SAP. It includes new, abolish and improve categorisation for each asset within a given WBS.

- Construction drawings.
- GIS (iView). By checking the installed date for the poles in the relevant section.

- **Overhead Lines (Added, Upgraded)**

The "added" field is the length of overhead line (including bare and ABC) added in kilometres for the project, for instance a new overhead line would have the full length in this field.

The "upgraded" field is the length of overhead line reconductored or re-tensioned (thermal uprate).

Line removal (if applicable in the project) is not considered at all in the CA RIN.

This information is available in the project detailed scope of work or statement of works and needs to be manually added for each length added or modified. This information can sometimes be found on settlement rules in SAP too for validation.

- **Underground Cables (Added, Upgraded)**

The "added" field is the length of underground cable added in kilometres for the project, for instance a new underground cable would have the full length in this field.

The "upgraded" field is the length of underground cable replaced with a larger rated cable or bentonited (thermal uprate).

Cable removal (if applicable in the project) is not considered at all in the CA RIN.

This information is available in the project detailed scope of work or statement of works and needs to be manually added for each length added or modified. This information can sometimes be found on settlement rules in SAP too for validation.

- **Switchgear (Added, Upgraded)**

While not requested in the CA RIN, the units of switchgear added or upgraded during a feeder project need to be added manually from the description in the detailed scope of work or business case.

Where switches/isolators are integrated into a single unit (eg. disconnector switch with integrated earth switch), then UE has assumed that this is one unit.

The settlement rules can be used to verify the number of units added particularly for the newer projects.

- **Expenditure (Labour, Materials, Contracts, Other direct)**

The expenditure columns were populated using data from SAP.

- **Total Direct Expenditure**

This is a formulated cell which does not need to be completed; it should not be typed over.

- **All Related Party (Margins, Total)**

Related Party (Margins) was sourced from SAP.

- **All Non-Related Party (Contracts)**

Related Party (Margins) was sourced from SAP.

- **Land and Easements**

Land and easement costs associated with each project are obtained from SAP project IDs with activity classifications “GP”. Land purchase expenditures are costs associated with the purchase of land for a new line or an upgrade of an existing line. Easement expenditures are costs associated with compensating land owners for easement acquisition.

- **Comments**

Although a column is not provided in the CA RIN for comments UE has recorded for each project in the CA RIN, the budget, business case value, commission year and the project COWP tracking ID, all of which is available in the “AMP Project List”. This extra information helps to completely define the project.

- **Project ID**

While not included on the CA RIN, the project ID is the SAP Project code, this ID can be found using any of the following methods:

  - From the CAPEX Works Program Project Reconciliation spread-sheet
  - From the Request for Statement of Works (RSOW) in the project folders
  - Searching SAP using the project builder (CJ20N) to return the code for the project description
  - Use the financial report to link the SAP code (WBS with no sub) to the description
  - Using the Project Lists to populate from the relative field

Sometimes multiple project IDs exist, particularly those projects that were in-flight during the UE hand-back from Jemena. Where this is the case, all project IDs are listed. Where the project ID commences with AAM, they are recorded in Alinta SAP 4.6c. Where a project ID commences with UED, they are recorded in UE SAP ISU.

- **Year Incurred**

While not included on the CA RIN, this provides the year of the final expenditure for the project.

- **Total Expenditure**

Although a column is not provided in the CA RIN, the summation of all expenditure columns (barring the land and easement expenditure) should tally the total cost of the project. To verify and reconcile the costs, this summated cost has been compared with the total project cost in SAP as recorded in the regulatory accounts, the business case value and the budgeted value.

3.4. Augex data – total expenditure

This table is segmented into columns containing calendar year expenditure. The rows are by each demand capex category.

Actual network capex splits obtained from the “Reg Accounts Summary” spread-sheet and summarised in “UE Expenditure Actual.PDF” file which is a summary of the breakdown provided by Service Delivery in the CA RIN Reconciliation files titled “UE Reg Account Financial Data” is used to populate this table. The mapping between this file and this table are as follows

- Transfer contents of ‘DZ’ to the “subtransmission substations, switching stations, zone substations” row
- Transfer contents of ‘DO’ to the “sub-transmission lines” row
- Transfer contents of ‘DL’ to the “other assets” row and re-label row as Reactive Power Compensation
- Transfer contents of ‘DS’ across “HV feeders, distribution substations and LV feeders”. As ‘DS’ maps into three rows in this table, it is necessary to determine the sum of the individual expenditure for each of these categories using the projects in Tables 2.3.3, 2.3.4 and 2.3.5 for each year then, adjust for seasonalisation of the projects using the seasonalisation of total “DS” in the regulatory accounts.
- Transfer the summations of land and easement purchases from the individual projects list for HV feeders, distribution substations and LV feeders respectively into the relevant land and easements cells.

Some adjustment of costs from one category to the other may be required where a project is incorrectly classified in the regulatory accounts.

The sum of all of these costs reconcile to regulatory accounts. If not the costs are manually adjusted to ensure consistency between the CA RIN and Annual RIN.

4. Connections

The following points were considered for connections:

- The connection expenditure provided does not net customer contribution. It represents gross expenditure. It also includes those assets (and expenditures) that have been gifted to UE in the cases where the customer has performed their own connection.
- Any connection expenditure included is Capex expenditure and does not include any Opex. The expenditure included is only related to Standard Control Services. The expenditure excludes any expenditure related to Alternative Control Services.
- It is assumed that all financial numbers entered into the tables of Section 2.5 are dollars-of-the-day (nominal terms).
- Annual information is presented as calendar years.
- It does not include Demand (augmentation) related projects and expenditure. The Demand expenditure shall be included in sheet 2.3 of the CA RIN.

4.1. Descriptor metrics

This table outline the data requirements related to new connections volume and expenditure. The volume and expenditure data is required to be categorised onto the following connection subcategories with a descriptor metric defining the data requirements for each subcategory:

- **Residential:** this would include volume of end-user metered connections (underground & overhead), any (HV/LV/ distribution substation) augmentation expenditure/volume/MVA/line km as a result of the new connections. Also it is required to provide mean days for connecting residential customer, GSL payments ($ & volume), volume of customer complaints relating to connection services.
- **Commercial/Industrial:** this would include volume of end-user metered connections (underground & overhead), any (HV/LV/ distribution substation) augmentation expenditure/volume/MVA/line km as a result of the new connections.
- **Subdivision:** this would include volume of subdivision installations (underground & overhead), any (HV/LV/ distribution substation) augmentation expenditure/volume/MVA/line km as a result of the new subdivision.
- **Embedded generation:** this would include volume of embedded generation installations (underground & overhead), any (HV/LV/ distribution substation) augmentation expenditure/volume/MVA/line km as a result of the new embedded generator connections (including solar PV).

The following were considered in providing the data requirement for Table 2.5.1:

1) The expenditure related to connect new end-user customer to the existing UE LV network were excluded. This excluded expenditure involves installation of the customer service line and end-user metering. This expenditure is classified under unitised pricing.

2) Individual LV residential end-use connections are well spread over UE network with a negligible impact on the UE network as a result of these connections, therefore there were no LV/HV/distribution substation augmentation spend for individual residential connections.

3) In the absence of the data related to actual days required to complete a new residential connection (within 10 days), it is assumed 8 days for completing an underground service connection and 5 days for completing an overhead service connection. Actual connections with days over the compliance period (10 days) are available and used to estimate the actual mean day required to connect a residential customer.

4) Embedded generation data included the small-scale embedded generations' volumes only. There were no LV/HV/distribution substation augmentation spend as a result of installing the small-scale embedded generations as these are connected using an automatic connection process.

A number of lines and tables within this section of the draft CA RIN template required clarification with the AER in order to understand precisely what data was to be provided. The details about the points which needed to be clarified with the AER are shown below. This information has been recorded throughout this procedure document in sections relating to each table.

Section	Query	AER Response and Clarification
Residential and Industrial/Commercial Connections	Does the residential section relate to the number of new connections in terms of non-unitised projects or all unitised connections (captured as meter installation)?	The AER confirmed that this was end-user meter installations or final connections only and did not account for any larger projects. One meter installed would count as one installation.
Subdivision Connections	Does the volume of connections recorded in each area refer to: - The number of potential customers? - The number of projects/subdivisions completed? - The number of customers which connected to the subdivision broken down annually	The AER confirmed that this was the number of projects completed, as in the number of subdivisions, and not the number of potential customers or when they connect. Instead the potential customers should be counted in the residential section as they connect to the network.
Distribution Substations	Does this section refer to the number of substations installed or the number of projects completed with a total capacity installed within the threshold?	The AER confirmed that this was the number of projects with the total installed capacity falling within the thresholds stated. Meaning that one project with several substations would be counted as one in this section.
Distribution Substations	Does the total spend relate to the total spend on the project or only the substation?	The AER confirmed that this was the total spend on the project for which the substation was installed
Connection Type	Should the underground/overhead volumes sum to equal the total volumes in the connection location sections?	The AER confirmed that this was the case.

Section	Query	AER Response and Clarification
MVA added	Does this refer to the capacity added to the network or the demand added to the network?	The AER confirmed that this section refers to the capacity added.

This table needs to be populated using the information collected from CIS+ (customer information system), connection projects (SAP) and the reports generated for AEMO from the UE Embedded Generation Register. The table breaks down new connections data into subcategory and construction type which is called "descriptor metric". The following summarises the data sources for the provided data.

Subcategory	Descriptor Metric	Source of data
Residential Commercial/Industrial	New connections (vol) Underground (vol) Overhead (vol) Added capacity (MVA) Added line km (LV/HV) Augmentation spend (LV/HV) GSL payments/volume Mean days to connect Complaints (vol)	CIS+ CMU[2] CMZ[3] Settlement rule for CB[4] Settlement rule for CB SAP project spend for CB Historical GSL reports Historical data & assumptions (refer to 6.3) Historical data
Subdivision	No. of subdivisions (vol) Underground (vol) Overhead (vol) Added capacity (MVA) Added line km (LV/HV) HV augmentation spend (LV/HV) Cost per Lot	CH, CD & CS[5] Settlement rule (CH,CD & CS) Settlement rule (CH,CD & CS) Settlement rule (CH,CD & CS) Settlement rule (CH,CD & CS) Settlement rule (CH,CD & CS) Calculated
Embedded Generation	New connections (vol)	CIS+ & Report for AEMO

New customers data were extract from CIS+ for the period from 2009 -2013 and sorted based on customer class (Residential, Commercial and Industrial). The information for CM projects (connection projects related to installing new service to a customer) were extracted from SAP for the period from 2009-2013. CM projects are classified under CMU (underground connections) and CMZ (overhead connections). The volume breakdown of CMU and CMZ is obtained and projected on the new connection breakdown for Residential and Commercial/Industrial connections.

- **Distribution Substation Installation Volume and Expenditure**

The number of projects involving the installation of distribution substations must be recorded under the capacity for which the substation was installed. This is broken down into volume and expenditure by capacity.

This section is entirely project based as there are no unitised rates for substation installation and therefore an individual project must be carried out. The mapping can be made by using the SAP query “CN52” on the project WBS elements.

Once returned the equipment numbers and/or descriptions should be linked to a capacity and then the volumes should be mapped into the ranges indicated on the template. As the substations are linked to the projects, the total expenditure for each relevant project should also be mapped into the spend section. Each unique transformer line in the extract should be mapped to its exact rating.

As this is project based there will be no installations of substations for residential connections, only for project data sources in subdivision and commercial/industrial. Any activity code starting with “CB” is a business project and these are the projects which should be mapped into the distribution substation section. The only exception to this is “CBH-EE” which is an activity code which refers to embedded generation projects; this would be classified in the embedded generation section (if any projects exist).

- **HV & LV Augmentation**

The length of circuit added by CIC projects should be recorded in the template using a combination of the project list generated and also by running the SAP settlement rules. In the UED SAP the quantity of the line items are recorded, for cables and conductors this quantity in recorded in metres. Using the asset classes the length of circuit added can be separated for each project using the WBS and then broken down by year. The template requires the length of circuit added in kilometres and therefore a conversion will need to be completed by a factor of 1000.

Prior to the UE Asset Management hand-back in 2011, Jemena Asset Management administered the SAP 4.6c (JSAP) system. Collecting the information from JSAP does not return quantities; instead a unit rate should be developed from the available data in the UED SAP. It is possible to ascertain which projects had cable or conductor in them, and also the division of the total project expenditure into each asset class, therefore the historical unit rates should be able to be applied reasonably accurately for breakdown into HV and LV conductor.

Table 7.1: Asset classes that refer to types of cable or conductor in SAP

UED SAP (IS-U)		JSAP (4.6c)	
HV Cable/Conductor	**LV Cable/Conductor**	**HV Cable/Conductor**	**LV Cable/Conductor**
30102 30105	30103 30106	30101 30102 30104 30105	30103 30106

The JSAP settlement rules extract does not include a quantity for each line leading to a shortfall of rigid information in this regard. This was overcome by using a unit rate developed from the information available from the UED SAP system. The total expenditure on each type of conductor (HV/LV) was broken down for business and subdivision projects and then divided by the total length of conductor added at that expenditure. This was then used with the expenditure returned from the settlement rules for JSAP in order to return a length of circuit added for years previous to 2011. The equation below shows the method undertaken in order to develop the unit rate.

$$unit\ rate\ \left(\frac{km}{\$}\right) = \frac{total\ length\ of\ circuit\ added\ for\ the\ UED\ SAP\ entries}{total\ expenditure\ from\ UED\ SAP\ on\ asset\ classes\ relating\ to\ that\ circuit\ class}$$

By multiplying the unit rate by the expenditure returned for each class in JSAP the length of conductor added for the previous years can be determined.

The amount of capacity added must be recorded in terms of MVA (UE has applied the nameplate rating as the amount of capacity added), as the only addition of capacity would be added through a distribution substation only the projects which have resulted in the installation of a substation will have added capacity. The data which was collected for the distribution substation section should be summed annually giving the total MVA added under each heading.

- **GSL and Customer Complaints (Residential Only)**

This information is directly available from CMS historical reports (Customer & Market Services group). The GSL data has been reconciled to the annual RIN statements.

- **Mean Days to Connect Residential Customer**

Based on the info about GSL payments to customers for delays above 10 days ($50 for one day delay), the number of days above 10 were calculated for every customer with GSL payment. It is assumed that rest of the customers that did not receive GSL payments had their connections completed within 10 days (8 days assumed for underground connections & 5 days assumed for overhead connections). Using the customer class identifier, Commercial/Industrial customers were excluded.

- **Cost per Lot (Subdivision Only)**

This is a calculated field. Project details (expenditure>$2000, volume and no. of lots) were extracted from SAP for the period 2009-2013 for each of the CH & CS projects. Unit rates (spend/volume) were derived for each. Based on the average number of lots of 25 for CH and 2.5 for CR, the cost per lot was calculated. CD projects were excluded for this calculations, as the spend data per single CD project is unitised (bucket) and do not reflect the spend for a single subdivision.

This table focusses more on the breakdown of expenditure in terms of complexity of the connection ‘connection classification’. Again this is done with a connection subcategory breakdown into residential, commercial/industrial, subdivision and embedded generation.

The following provides a description of the provided data for each subcategory:

Subcategory	Connection Classification	Source of data/criteria
Residential	Simple connection LV (vol/spend) Complex connection LV (vol/spend) Complex connection HV (vol/spend)	It is assumed that all Residential connections (CIS+) were established through simple connections LV. No connections reported under complex connections (LV/HV) There is no spend to augment LV/HV network to establish residential connections
Commercial/Industrial	Simple connection LV (vol/spend) Complex connection HV with minor HV works (vol/spend) Complex connection HV with upstream asset work (vol/spend) Complex connection HV (customer connected at HV) Connection to sub-transmission (vol/spend)	Remaining connections from the volume of new connections after the residential connections types have been assigned All CB projects with distribution substation installations/modification which are coded as (CBK,CBP,CBG,CBI & CBS) Any of the CB project with cost exceeding $400,000 Any projects related to connection of HV customers which are coded as (CBH) No projects or connections under this category during 2009-2013
Subdivision	Complex connections LV (vol/spend) Complex connection HV (with upstream work) Complex connections HV (with no upstream work)	CHL projects are those that require supply provided via an LV extension from existing LV circuit CHH projects are those that requires HV extension works Any CH projects remaining from above criteria (>$400,000)
Embedded Generation	Simple connections LV Complex HV connections (Small capacity) Complex HV connections (Large capacity)	All the PV embedded generations' connections were captured as LV simple connections as per Table 2.5.1. There is no LV/HV augmentation spend considered. Embedded generation register which keeps historical data were used to capture the HV connected embedded generation. CIC project data were used to capture the connection scope & expenditure

Note: For complex connections all data is net addition of circuit line length resulting from the augmentation work.

4.2. Cost metrics by connection classification

This table outlines the data requirements related to new connections volume and expenditure. The volume and expenditure data is required to be categorised onto the following connection subcategories with a connection classification metric defining the data requirements for each subcategory:

- **Residential:** this would include expenditure and volume of end-user metered connections for each connection classification (simple connection LV/complex connection LV/complex connection HV).

- **Commercial/Industrial:** this would include expenditure and volume of metered connection installations for each connection classification (simple connection LV/ complex connection HV (upstream work or no upstream work)/ connection to HV sub-transmission).

- **Subdivision:** this would include expenditure and volume of subdivision installations for each connection classification (complex connection LV/ complex connection HV with or without upstream HV work).

- **Embedded generation:** this would include expenditure and volume of end-user connections for each connection classification (simple connection LV/ complex connection HV small capacity & large capacity).

  Note: There is some discrepancy between the overall new connections obtained from CIS+/AMI and the one provided to NIEIR for the EDPR (2009-2013). The main reasons for this discrepancy are the transition of IT systems (JSAP to UE SAP) and the CIS+ to AMI rollout. Therefore the CIS+/AMI new connections were adjusted to reduce the discrepancy.

5. Non Network Expenditure

5.1. Non-network expenditure

Expenditure has been sourced from SAP and reconciled to the annual RINS. Data has been attributed to the relevant RIN headings based on internal job orders in SAP. Additional rows have been added to account for fork lifts and trailers.

Table 2.6.1 requires the OPEX and capital expenditure (CAPEX) for the following categories:

- IT and communications
- Car
- Light Commercial Vehicle
- Elevated Work Platform (LCV)
- Elevated Work Platform (HCV)
- Building and property
- Other

UE does not own any elevated work platform (LCV) and hence, the figures for this category were 0. As per the annual RIN statements all capital expenditure in the above categories have been allocated to standard control.

5.1.1. CAPEX expenditure

The annual CAPEX expenditure for each motor vehicle RIN category was based on data extracted from SAP. The following outlines the procedure to obtain the annual CAPEX expenditure in the format required by Table 2.6.1 of the Category Analysis RIN template:

1. Obtain the list of motor vehicles bought in the calendar year by filtering the 'capitalised date' column in the UE Motor Vehicle ZFAL 2009 to 2013 spread sheet for the calendar year.

2. Segregate this list of motor vehicles into motor vehicle RIN categories by filtering the 'RIN category' column.

3. Summate the 'Book Acquisition Cost' column for each motor vehicle RIN category to obtain the annual CAPEX expenditure per motor vehicle RIN category.

For the other categories data was extracted from SAP and allocated to the CA RIN headings via a mapping on internal job codes.

5.1.2. OPEX expenditure

UE has defined OPEX expenditure as motor vehicle maintenance costs only. This was per the following instructions in the AER Final Distribution Category Analysis document:

"Motor Vehicle expenditure directly attributable to direct expenditure categories, for example motor vehicle expenditure directly attributable to activities giving rise to replacement capital expenditure, must be included in the expenditure reported in those replacement capital expenditure categories and any reported unit costs."

In addition, UE Service Providers utilised UE owned vehicles to conduct work on UE's network. Motor vehicles expenses incurred by UE Service Providers were grouped with plant costs and captured as part of Service Provider project installation costs. Hence, it was impossible to segregate motor vehicles fuel, registration and insurance costs. Thus, these have been excluded from the OPEX expenditure.

The OPEX expenditure for each motor vehicle RIN category was based on the maintenance costs data in the LCMP.

The following outlines the procedure to obtain the annual OPEX expenditure in the format required by Table 2.6.1 of the Category Analysis RIN template:

1. The LCMP provided the maintenance costs of each motor vehicle per motor vehicle RIN category. Based on this data, the average maintenance cost of each motor vehicle RIN category for the various motor vehicle age was calculated.
2. Insert a new column called 'Age' in the UE Motor Vehicle ZFAL 2009 to 2013 spread sheet. Populate this column with the age of each motor vehicle based on the 'capitalised date' column.
3. Insert a new column called 'OPEX' in the UE Motor Vehicle ZFAL 2009 to 2013 spread sheet. Populate this column with the average maintenance costs calculated in step 1 based on the motor vehicle age determined in step 2.
4. Segregate the motor vehicles into motor vehicle RIN categories by filtering the 'RIN category' column.
5. Summate the 'OPEX' column for each motor vehicle RIN category to obtain the annual OPEX expenditure per motor vehicle RIN category.

Opex for SCADA is included in the maintenance template

IT, building and property opex has been taken from the annual RIN and allocated to the various headings based on an assessment of internal cost centres.

5.2. Annual descriptors metrics – IT and Communications expenditure

Although the overall heading of the table is for expenditure the headings of the columns refer to volumes. UE has populated the table with volume data.

UE has also allocated all the devices and user numbers to standard control services. IT capex is allocated to standard control as per the annual RIN accounts except when it is for AMI. Likewise employee numbers are not scaled for ACS. ACS is a small component of UE's actual work with a bulk of the work outsourced to service providers. Therefore the numbers are estimated on the basis that no allocation to ACS has taken place.

- Employee numbers - based on payroll data based on payroll data for those years. It is limited to those engaged directly by UE and does not include resources engaged by service providers.

- User numbers for 2011 to 2013 is based on an extract from an internal database. It contains active users only and is for users both employed by UE and for external parties accessing UE systems. For prior years it is an estimated based on 2011 and assumes limited growth in user numbers. We have used this approach as prior to 2011 UE's as actual data is not available due to the contracting arrangements with Zinfra. UE does not have information for these periods due to the contracting arrangements in place at that time.

- Number of devices is based on an internal warranty spread sheet with external provider. For prior years it is an estimated based on 2011 and assumes limited growth in user numbers. We have used this approach as prior to 2011 UE's as actual data is not available due to the contracting arrangements with Zinfra. UE does not have information for these periods due to the contracting arrangements in place at that time.

5.3. Annual descriptor metric – motor vehicles

Motor vehicle data were obtained from the following two data sources:

- SAP custom transaction report Z_FA_List
- Fleet Lifecycle Management Plan (LCMP)

The motor vehicles operating expenditure (OPEX) and average kilometres travelled data were obtained from the life cycle management plan (LCMP). Therefore this data is considered to be estimated. All other motor vehicle data were sourced from the SAP custom transaction report Z_FA_List for each calendar year. The results generated from the SAP custom transaction Z_FA_List for each calendar year from 2009 – 2013 were stored in separate tabs in an Excel spreadsheet named 'UE Motor Vehicle ZFAL 2009 to 2013'.

5.3.1. Motor Vehicle RIN Categories

The motor vehicles listed in the spread sheet 'UE Motor Vehicle ZFAL 2009 to 2013' were manually categorised by the description in the 'desc line 1' column of the spread sheet. The motor vehicles were categorised into the following categories based on the definitions in the AER Final Distribution Category Analysis RIN document:

- Car
- Light Commercial Vehicle
- Heavy Commercial Vehicle
- Elevated Work Platform (LCV)
- Elevated Work Platform (HCV)

This manual categorisation was conducted for each calendar year and was saved in a new column named 'RIN category' in each tab of the spread sheet. UE does not own any elevated work platform (LCV). UE owns forklifts and trailers. Based on AER's definitions and requirements, forklifts and trailers are categorised as non-network other expenditure category and have to be reported as separate items if UE had incurred $1 million or more (nominal) in capital expenditure over the last five regulatory years for a given type or class of assets. As UE had not spent $1 million or more in capital expenditure over the last five regulatory years on neither forklifts nor trailers, these forklifts and trailers are not required to be reported to the AER.

5.3.2. Average kilometres travelled

The average kilometres travelled for each motor vehicle RIN category was based on the distance travelled data in the LCMP. To deal with this inaccurate data, the following was undertaken to obtain the average annual kilometres travelled in the format required by Table 2.6.3 of the Category Analysis RIN template:

1. Cross reference the rego number in the LCMP with the UE Motor Vehicle ZFAL 2009 to 2013 spreadsheet to obtain the vehicle age.

2. As there were sufficient data for the first four years of each motor vehicle RIN category, the average distance travelled was calculated for each motor vehicle RIN category.

3. It was assumed that each vehicle of a motor vehicle RIN category travelled the same average distance regardless of age. Hence, the average kilometres travelled per motor vehicle RIN category was estimated to be the product of this average distance travelled and the motor vehicle volumes.

5.3.3. Number purchased

The volumes of motor vehicles purchased were based on the data in the spread sheet 'UE Motor Vehicle ZFAL 2009 to 2013'. Based on the results of steps 1 and 2 from the above section, count the number of motor vehicles purchased annually for each motor vehicle RIN category.

5.3.4. Number in fleet

The volumes of motor vehicles were based on the data in the spreadsheet 'UE Motor Vehicle ZFAL 2009 to 2013'.

The annual fleet volumes per motor vehicle RIN category was achieved by filtering the 'RIN category' column for each motor vehicle RIN category and counting the number of motor vehicles in each motor vehicle RIN category.

UE has not calculated an average of fleet for any one year – the closing balance has been used.

5.3.5. Proportion of total fleet expenditure allocated as regulatory expenditure

UE owned cars were utilised by UE and UE Service Providers. UE utilised their cars for standard control services. However, UE Service Providers did not report on the usage of UE owned vehicles. Thus, it was not possible to separate the usage of cars into regulatory and other purposes. However, cars are predominately used for standard control services and hence, it was reasonable to allocate all cars expenses to regulatory expenses.

Light commercial vehicles, heavy commercial vehicles and elevated work platforms (HCV) are required for standard control services. Hence, these motor vehicle categories expenditure were all allocated to regulatory expenditures.

6. Maintenance

6.1. Descriptor metrics for routine and non-routine maintenance

There were different methods to obtain the quantity of assets at year end for each maintenance asset category. This is due to the different regulatory reporting requirements of previous years (i.e. calendar years 2009 – 2012). Hence, asset data were captured and recorded differently in those years.
The rest of this section will detail the method to obtain the quantity of assets at year end for calendar years 2009 – 2013 per maintenance asset category.

- **Pole Tops and Overhead Lines Maintenance**

The pole quantities were extracted from the archived AM/FM web reports based on the same methodology as described in UE Procedure document UE PR 2310 Internal Procedure to Populate Asset Information Data for the Economic Benchmarking RIN Templates. The actual annual figures were the sum of all the poles produced by the archived AM/FM reports for each calendar year. These poles quantities included non-UE poles with UE owned cross arms.

- **Service Lines Maintenance**

The number of customers was taken from the Economic Benchmarking RIN that has previously been audited.

For the period 2006-2009 customer data was wholly retained within the CIS system. Customers have been transitioning platforms from CIS to SAP from 2010 to present to cater to the requirements of the AMI rollout.

Customer numbers for the period to 2009 are based upon reports generated from CIS that capture the status of customers by tariff by month. The customer counts represent the status of customers by tariff as reported on 31st of December each year. These numbers tie back to those reported in the Electricity Service Performance Report and submitted RIN data in the previous periods.

The period 2010-2013 sees customer data being consolidated from 2 systems (CIS & SAP). For CIS customers the data has been derived as per the process described previous. SAP customer tariff data is derived from monthly queries of the customer database. Customer tariff data is then harmonised form the two data sources to ensure the correct timing of customers transferring between the two systems is captured.

- **All Poles Inspection and Treatment**

As only poles owned by UE will be inspected and treated, the quantities of poles inspected and treated will be less than the quantities of poles maintained.

The UE poles quantity for calendar year 2013 was the summation of all the pole quantities in the Poles spread sheet. For the procedure to obtain the data in the Poles spread sheet, refer to UE Procedure document UE PR 2311 Annual/Category Analysis RIN - Population of Poles Asset Class Data.

Due to different regulatory reporting requirements of previous years, the UE poles quantity were not captured and recorded for the calendar years 2009 – 2012. These quantities were back estimated based on the following formula:

$$UE\ Pole\ quantity\ in\ year\ n = \frac{Maintained\ pole\ quantities\ in\ section\ 6.2.1\ for\ year\ n}{Maintained\ pole\ quantities\ in\ section\ 6.2.1\ for\ year\ n+1} \times UE\ Pole\ quantity\ in\ year\ n+1$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009).

This was a reasonable estimate as it was based on the proportion of number of poles maintained across the years which correlated to the quantity of UE poles (i.e. increase in number of poles maintained may be attributed to an increase in UE poles quantities).

- **All Overhead Assets Inspection**

The annual overhead line length was the summation of all the annual overhead line lengths in the 2013 Economic Benchmarking RIN.

- **LV – 11 to 22kV Cables Maintenance**

The annual LV - 11kV to 22kV cable length was the summation of the annual 11kV and 22kV cable lengths in the 2013 Economic Benchmarking RIN.

- **33kV and above Cables Maintenance**

The annual 33kV and above cable length was the annual 66kV cable lengths in the 2013 Economic Benchmarking RIN.

UE does not have 33kV voltage and voltages higher than 66kV in its network.

- **CBD cables Maintenance**

UE does not own CBD cables. Hence, this field is 0 for all years.

- **Non-CBD cables Maintenance**

As UE does not own CBD cables, all UE cables are categorised as non-CBD cables. Hence, this was the sum of the lengths for LV – 11 to 22kV cables.

- **Distribution Substation Transformers Maintenance**

The distribution transformers quantity for calendar year 2013 was the summation of all the distribution transformers quantities in the Distribution Transformer spreadsheet.

Due to different regulatory reporting requirements of previous years, the distribution transformers quantities were not captured and recorded for the calendar years 2009 – 2012. These quantities were back estimated based on the following formula:

$$Distribution\ transformer\ quantity\ in\ year\ n = \frac{Substation\ quantity\ in\ year\ n}{Substation\ quantity\ in\ year\ n+1} \times Distribution\ transformer\ quantity\ in\ year\ n+1$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009).

The annual substation quantities were extracted from the archived AM/FM web reports based on the same methodology as described in UE Procedure document UE PR 2310 Internal Procedure to Populate Asset Information Data for the Economic Benchmarking RIN Templates. The annual substation quantity was the sum of all the substations produced by the archived AM/FM reports for each calendar year.

This was a reasonable estimate as it was based on the proportion of substation quantities across the years which correlated to the quantity of distribution substations (i.e. an increase in substation quantities will increase distribution transformers quantities).

- **Distribution Substation Switchgear (Within Substations and Stand Alone Switchgear) Maintenance**

This category entails the summation of the quantities of distribution switchgear located within substations and outside substations (i.e. in the distribution network). The total quantity of all distribution switchgear (located within and outside substations) for calendar year 2013 was the summation of all the switchgear quantities in the HV Switches spreadsheets.

The quantities of the distribution switchgear located outside substations were extracted from the archived AM/FM web reports based on the same methodology as described in UE Procedure document UE PR 2310 Internal Procedure to Populate Asset Information Data for the Economic Benchmarking RIN Templates. The annual quantity of distribution switchgear located outside substations was the sum of all the switches produced by the archived AM/FM reports for each calendar year.

Due to different regulatory reporting requirements of previous years, the quantities of the distribution switchgear located within substations were not captured and recorded for the calendar years 2009 – 2012. These quantities were back estimated based on the following formula:

$$Number\ of\ Switches\ located\ within\ substations\ in\ year\ n = \frac{Quantity\ of\ Switches\ located\ outside\ substations\ in\ year\ n}{Quantity\ of\ Switches\ located\ outside\ substations\ in\ year\ n+1} \times Number\ of\ Switches\ located\ within\ substations\ \text{in year n} + 1$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009).

This was a reasonable estimate as it was based on the proportion of switches located outside substations across the years which correlated to the quantity of switches located within substations (i.e. an increase in quantity of switches located within substations will increase the quantity of switches located outside substations in the distribution network).

- **Distribution Substation – Other Equipment Maintenance**

Automatic Circuit Reclosers (ACRs) and Remote Control Gas Switches (RCGSs) were classified under this category.

The total quantities of ACR and RCGS for calendar year 2013 was the summation of all the ACR and RCGS quantities in the HV Switches spreadsheets. For the procedure to obtain the data in the HV

Switches spreadsheets, refer to UE Procedure document UE PR 2319 Annual/Category Analysis RIN - Population of HV/LV Switches Asset Class Data.

Due to different regulatory reporting requirements of previous years, the quantities of the distribution switchgear located within substations were not captured and recorded for the calendar years 2009 – 2012. These quantities were back calculated based on the following formula:

$$ACR\ and\ RCGS\ quantities\ in\ year\ n = (\text{total}\ ACR\ and\ RCGS\ quantities\ in\ year\ n+1) - (ACR\ and\ RCGS\ installed\ in\ year\ n+1)$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009)

As there were no ACR and RCGS replaced due to failure in the past 5 years, the quantities of ACR and RCGS installed each year were obtained from the age profiles of ACR and RCGS in tab 5.2 of the Category Analysis Benchmarking RIN templates.

- **Distribution Substation – Property Maintenance**

The quantity of distribution substations with property for calendar year 2013 was the summation of all the distribution transformers that were not pole mounted distribution transformers in the Distribution Transformer spreadsheet. For the procedure to obtain the data in the Distribution Transformer spreadsheet, refer to UE Procedure document UE PR 2317 Annual/Category Analysis RIN - Population of Distribution Transformers Asset Class Data.

Due to different regulatory reporting requirements of previous years, the distribution substation quantities were not captured and recorded for the calendar years 2009 – 2012. These quantities were back estimated based on the following formula:

$$Distribution\ substation\ quantity\ in\ \text{year n} = \frac{Distribution\ Transformer\ quantity\ in\ year\ n}{Distribution\ Transformer\ quantity\ in\ year\ n+1} \times Distribution\ Substation\ quantity\ in\ year\ n+1$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009).

This was a reasonable estimate as it was based on the proportion of distribution transformers across the years which correlated to the quantity of distribution substations (i.e. increase in distribution transformer quantities may imply increase in quantities of distribution substation with property).

- **Transformers – Zone Substation Maintenance**

The Zone Substation (ZSS) transformers quantity for calendar year 2013 were obtained from the UE Lifecycle Management Plan (LCMP) document UE PL 2028 ZSS Power Transformers Lifecycle Strategies.
Due to different regulatory reporting requirements of previous years, the ZSS transformers quantities were not captured and recorded for the calendar years 2009 – 2012. These quantities were back calculated based on the following formula:

$$ZSS\ transformer\ quantity\ in\ year\ n = (ZSS\ transformer\ quantities\ in\ year\ n+1) - (ZSS\ transformers\ installed\ in\ year\ n+1)$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009).

The number of ZSS transformer installed each year were based on UE Subject Matter

Expert knowledge on the ZSS transformers. There were either a few or no ZSS transformers installed each year.

The ZSS transformers installed in 2010 were due to demand increase whilst the ZSS transformers installed in 2012 and 2013 were for replacement purposes.

- **Transformers – Distribution Maintenance**

The distribution transformers located within Zone Substations are the Zone Substation station transformers. The station transformers quantities were obtained from the Distribution Transformer spreadsheet. For the procedure to obtain the data in the Distribution Transformer spreadsheet, refer to UE Procedure document UE PR 2317 Annual/Category Analysis RIN - Population of Distribution Transformers Asset Class Data.

There was a constant quantity of station transformers across the years 2009 – 2013 as station transformers were neither added nor replaced in those years.

- **Transformers – HV Maintenance**

UE do not own any transformers in this category. Hence, the number of assets at year end were 0 for all years.

- **Zone Substation – Other Equipment Maintenance**

Circuit breakers (CBs), capacitor banks, current transformers (CTs) and voltage transformers (VTs) were classified under this category. The capacitor banks, CTs and VTs were grouped together as a subcategory under this Other Equipment category.

- **CBs**

The CB quantity for calendar year 2013 was the summation of all the CBs in the Primary spreadsheet. For the procedure to obtain the data in the Primary spreadsheet, refer to UE Procedure document UE PR 2321 Annual/Category Analysis RIN - Population of Zone Substation Primary Asset Class Data. Due to different regulatory reporting requirements of previous years, the CB quantities were not captured and recorded for the calendar years 2009 – 2012. These quantities were back calculated based on the following formula:

$$CB\ quantity\ in\ year\ n = \frac{ZSS\ transformer\ quantity\ in\ year\ n}{ZSS\ transformer\ quantity\ in\ year\ n+1} \times CB\ quantity\ in\ year\ n+1$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009).

The ZSS transformer quantities were determined in section .

This was a reasonable estimate as it was based on the proportion of ZSS transformers across the years which correlated to the quantity of CB (i.e. increase in ZSS transformer quantities will increase CB quantities).

- **Capacitor Banks, CTs and VTs**

The capacitor banks, CTs and VTs quantities for calendar year 2013 was the summation of all the capacitor banks and instrument transformers (i.e. CTs and VTs) quantities in the Primary spreadsheet. For the procedure to obtain the data in the Primary spreadsheet, refer to UE Procedure document UE PR 2321 Annual/Category Analysis RIN - Population of Zone Substation Primary Asset Class Data. Due to different regulatory reporting requirements of previous years, the capacitor banks, CTs and VTs quantities were not captured and recorded for the calendar years 2009 – 2012. These quantities were back calculated based on the following formula:

$$Cap\ bank, CTs\ and\ VTs\ quantity\ in\ year\ n = \frac{ZSS\ transformer\ quantity\ in\ year\ n}{ZSS\ transformer\ quantity\ in\ year\ n+1} \times Cap\ bank, CTs\ and\ VTs\ quantity\ in\ year\ n+1$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009).

The ZSS transformer quantities were determined in section □.

This was a reasonable estimate as it was based on the proportion of ZSS transformers across the years which correlated to the quantity of CTs and VTs (i.e. increase in ZSS transformer quantities will increase CTs and VTs quantities).

- **All Zone Substation Properties Maintenance**

The Zone Substation quantity was obtained from the UE LCMP document UE PL 2028 ZSS Power Transformers Lifecycle Strategies.

There was a constant quantity of zone substations across the years 2009 – 2013 as no zone substations were added to UE network.

- **Public Lights on Minor Roads Maintenance**

The public lights quantities are the number of luminaries (or commonly referred to as globes or lamps) replaced as part of public lights maintenance.

The number of public lights on minor roads for calendar year 2013 was the summation of all the luminaries on minor road in the age profiles of luminaries in tab 5.2 of the Category Analysis Benchmarking RIN templates.

Due to different regulatory reporting requirements of previous years, luminaries quantities have not been captured and recorded for the calendar years 2009 – 2012. However, the quantity of billable lanterns for the calendar years 2009 – 2012 could be obtained from the archived AM/FM reports. The billable lanterns were called public lights in the AM/FM reports. Hence, the luminaries quantities were back calculated based on the following formula:

$$Luminaries\ on\ minor\ road\ quantity\ in\ year\ n = \frac{Billable\ laterns\ quantity\ in\ year\ n}{Billable\ laterns\ quantity\ in\ year\ n+1} \times Luminaries\ on\ minor\ road\ quantity\ in\ year\ n+1$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009).
This was a reasonable estimate as luminaries quantities are proportional to lantern quantities.

- **Public Lights on Major Roads Maintenance**

The above process was repeated for luminaries on major roads.

- **SCADA & Network Control Maintenance**

This maintenance was based on the quantity of Remote Terminal Unit (RTUs) and associated system installed in ZSS. The quantity of SCADA system for calendar year 2013 was the SCADA system quantities in the Secondary spreadsheet. For the procedure to obtain the data in the Secondary spreadsheet, refer to UE Procedure document UE PR 2323 Annual/Category Analysis RIN - Population of Zone Substation Secondary System Asset Class Data.
Due to different regulatory reporting requirements of previous years, the SCADA system quantities were not captured and recorded for the calendar years 2009 – 2012. These quantities were back calculated based on the following formula:

$$SCADA\ system\ quantity\ in\ year\ n = \frac{ZSS\ transformer\ quantity\ in\ year\ n}{ZSS\ transformer\ quantity\ in\ year\ n+1} \times SCADA\ system\ quantity\ in\ year\ n+1$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009).

This was a reasonable estimate as it was based on the proportion of ZSS transformers across the years which correlated to the quantity of RTUs (i.e. increase in ZSS transformer quantities may increase RTU quantities).

- **Protection Systems Maintenance**

This maintenance was based on the quantity of protection relays installed in UE's ZSS. The quantity of protection relays for calendar year 2013 was the total number of protection relays in the Secondary spreadsheet. For the procedure to obtain the data in the Secondary spreadsheet, refer to UE Procedure document UE PR 2323 Annual/Category Analysis RIN - Population of Zone Substation Secondary System Asset Class Data.

Due to different regulatory reporting requirements of previous years, the protection relays quantities were not captured and recorded for the calendar years 2009 – 2012. These quantities were back calculated based on the following formula:

$$Protection\ relays\ quantity\ in\ year\ n = \frac{ZSS\ transformer\ quantity\ in\ year\ n}{ZSS\ transformer\ quantity\ in\ year\ n+1} \times Protection\ relays\ quantity\ in\ year\ n+1$$

Where n is the calendar year (i.e. 2012, 2011, 2010, 2009).

This was a reasonable estimate as it was based on the proportion of ZSS transformers across the years which correlated to the quantity of protection relays (i.e. increase in ZSS transformer quantities will increase protection relay quantities).

- **DC System Maintenance**

This maintenance was based on the quantity of battery banks and chargers installed in UE's ZSS. The quantity of battery banks and chargers for calendar year 2013 was the total number of battery banks and chargers in the Secondary spreadsheet. For the procedure to obtain the data in the Secondary spreadsheet, refer to UE Procedure document UE PR 2323 Annual/Category Analysis RIN - Population of Zone Substation Secondary System Asset Class Data.

- **Average Age of Asset Group**

The average age of all the asset groups in for calendar year 2009 were obtained from the 2009 EDPR.

The average age of all the asset groups in for calendar year 2013 were based on the mean economic life in tab 5.2 of the Category Analysis Benchmarking RIN templates.

Due to the different regulatory reporting requirements in the years 2010 – 2012, the average age of asset groups were not captured. Hence, the average age of assets groups for calendar years 2010 – 2012 were linear interpolation of the average age of asset groups in calendar years 2009 and 2013. This was the best estimate as it was expected that there were no significant changes in average age of asset groups over the last five years.

- **Inspection Cycle (Years) and Maintenance Cycle (Years)**

The inspection cycle and maintenance cycle for each asset group was extracted from either the following LCMP documents or the reliability centred maintenance (RCM) studies.

6.2. Cost metrics for routine and non-routine maintenance

For cost related data expenditure was sourced from SAP based the mapping of internal cost codes to RIN headings. UE has inserted a reconciling line into the template to ensure that it reconciles to annual RIN submission. This reconciliation amount includes the network control centre and other minor maintenance items not including in the headings per the CA RIN.

7. Vegetation Management

The regulations used to complete the RIN templates are based on:

- Electricity Safety Act 1998.
- Electricity Safety (Bushfire Mitigation) Regulations 2003.
- Electricity Safety (Electric Line Clearance) Regulations 2010
- Electricity Safety (Installations) Regulations 2009.

The regulations listed above lead to the expenditure outcomes in table 2.7.2 of the RIN.

7.1. Descriptor metrics by zone

Data for 2013 has been extracted from UE's GIS system for 2013 and has been scaled to equal the data provided in the economic benchmarking RIN. The EB RIN data was in total form only. Therefore this data is estimated and consistent in total with previously provided data. Prior year annual data is assumed to be the same as 2013. The north and south split is based on the service zones serviced by our two main service providers. UE does not keep any records on the length of vegetation corridors or average number of trees per maintenance spans. Data has also been extracted from the economic benchmarking RIN (e.g. Route line length and number and length of spans) and has been used to populate data in this RIN.

Urban and CBD Vegetation Maintenance Spans 2013.This information has been derived for the year "2013" from the VEMCO Vegetation Management System (VMS) database as of January 2014 covering the 2013 calendar year and is treated by UE as "Estimated". UE has not provided data for previous years as it would be unnecessarily burdensome to do so. It has been scaled to equal the data provided in the economic benchmarking RIN. The EB RIN data was in total form only. Therefore this data is estimated and consistent in total with previously provided data.

Rural Vegetation Maintenance Spans 2013) This information has been derived for the year "2013" from a report run out of the VEMCO VMS database as of January 2014 covering the 2013 calendar year and is treated by UE as "Estimated". UE has not provided data for previous years as it would be unnecessarily burdensome to do so. It has been scaled to equal the data provided in the economic benchmarking RIN. The EB RIN data was in total form only. Therefore this data is estimated and consistent in total with previously provided data.

The average number of trees has been estimated and reconciled to the EB RIN. UE does not currently have a requirement to collect specific tree information as current data is based on spans only. Therefore this information is estimated. The key assumption for this estimation is a review commissioned in 1999 that concluded that of the 340,000 trees UE was responsible for approximately 24% were in a rural area and the remaining 76% in an urban area. This has been assumed to be a reasonable split for 2013. Therefore the calculation is (340,000 * 76% * (% Maintenance Span Cycle /urban and rural maintenance spans.).

7.2. Expenditure metrics by zone

Data is sourced directly from SAP where codes are set up by zone to record the tree cutting expenditure of our contractors. Or recording systems record total tree cutting only and do not go to a level below that.

7.3. Descriptor metrics across all zones – unplanned vegetation events

Data is sourced from the F factor submission. This data has been extracted from DMS and has previously been audited as part of those submissions.

8. Emergency response

8.1. Emergency response expenditure (OPEX)

Actual cost data is sourced directly from SAP. For 2009 and 2010 the cost has been recorded as estimated data based on limited data available due to the contracting arrangements in place. For 2011, 2012 and 2013 has used actual data from SAP to populate total expenditure.

UE has used the MED days as per template 6.3 for years 2011 to 2013 to populate expenditure for storm days. For 2009 and 2010 actual cost data is not available for these individual days (noting that limited cost data is not available for prior years as described above). UE has then gone to the source document for that day to determine the actual cost of faults for that day. UE has marked the template as estimated data as actual cost data can be invoiced in the following months as the service providers finalises its own cost capture and will invoice in subsequent months – in particular on days where there has been considerable fault activity. UE has not reviewed the following months data to allocate additional actual cost data to the days when an MED has been recorded.

9. Overheads

9.1. Network overheads expenditure

Network management costs were sourced directly from annual RINS and annual regulatory accounting statements. UE does not directly allocate these costs to the headings provided by the RIN therefore an estimate has been provided for the disaggregated headings per the RIN.

This was based on a headcount of the current organisational structure. Each current role was allocated to the required RIN heading to determine an overall percentage. This was then applied for each year.

9.2. Corporate overheads expenditures

Data was extracted directly from SAP and reconciled to the annual RIN.

10. Labour

10.1. Cost metrics per annum

For 2009 and 2010 the headcount numbers cannot be allocated any further. The data is based on internal management reports. During this period the company was largely outsourced with minimal internal labour.

For 2011 to 2013 UE has used 2013 actual data and prorata that percentage to prior years. The detail for 2013 has been extracted from the company's payroll system and reconciling to the organisational structure.

Total labour cost has been extracted from the RIN and annual regulatory reports. The same process has been applied i.e. 2013 actual payroll data had been used and the same percentages applied for 2011 and 2012.

Total costs is actual data for all years, the disaggregation is estimated for years 2009 to 2012.

The average productive work hours is estimated and has been calculated assuming daily hours of 7.6.

UE has had no stand-down occurrences.

The average hourly rate is formula driven based on the data in Table 2.11.1

11. Input Tables

Data for this table has been extracted from SAP or estimated – refer description below. Note that for 2009 and 2010 actual cost data was limited and has therefore been allocated entirely to contract cost. The margin was removed based on the contractual arrangement in place at that time. The descriptions below refer entirely to the period 2011 to 2013 unless otherwise indicated.

- Vegetation management been extracted from SAP. This service is provided entirely by UE's service providers. Internal job codes have been established to capture vegetation codes by each region. A service provider manages each region for UE and therefore the cost capture by activity by region can be extracted from SAP.

- Routine maintenance - for each of the headings provided UE has internal codes established to determine the actual cost provided by the service provider. 2012 is the first full year of the operation of the new contracting arrangement and actual cost data for each of the cost elements is provided and reported in the RCA RIN. The allocation to routine maintenance is an engineering assessment of various categories within the internal costing system.

- Non-routine maintenance - for each of the headings provided UE has internal codes established to determine the actual cost provided by the service provider. 2012 is the first full year of the operation of the new contracting arrangement and actual cost data for each of the cost elements is provided and reported in the RCA RIN. The allocation to non-routine maintenance is an engineering assessment of various categories within the internal costing system.

- Overheads is based on the amount reported in the annual RIN. Labour costs have been determined in accordance with template 2.11. The remainder of the overhead costs has been allocated to other.
  .
- Augmentation costs have been allocated to other and reconciled to template 2.3. At the time of preparing this template UE has been unable to allocate the costs to a further level of granularity.

- Connections costs have been allocated to other and reconciled to template 2.5. At the time of preparing this template UE has been unable to allocate the costs to a further level of granularity.

- Emergency response costs for MED and storm days has been prepared in accordance with template 2.9.
- Public lighting expenditure includes both capital and operating costs. . At the time of preparing this template UE has been unable to allocate the costs to a further level of granularity.

- Metering - data has been sourced from sheet 4.2 and is for both operating and capital. At the time of preparing this template UE has been unable to allocate the costs to a further level of granularity.

- Fee-based - data has been sourced from sheet 4.3 and allocated to other. Further breakdown is not available for this activity.

- Quoted - data has been sourced from sheet 4.4 and allocated to other. Further breakdown is not available for this activity.

- Replacement - for each of the headings provided UE has internal codes established to determine the actual cost provided by the service provider. 2012 is the first full year of the operation of the new contracting arrangement and actual cost data for each of the cost elements is provided and reported in the CA RIN.

- Buildings and property expenditure is for both operating and capital costs. No labour has been attributed to these costs. All costs are considered to be “other” costs.

- Other expenditure is for both operating and capital costs. No labour has been attributed to these costs. All costs are considered to be “other” costs.

12. Public Lighting

Total lights include those lights that have been gifted to UE and customer funded. UE is required to maintain and operate all lights including those gifted and customer funded.

12.1. Descriptor metrics over current year

This data is sourced from annual RIN and has been audited as part of that process. This in turn has been sourced from GIS. Descriptor metrics annually.

Expenditure has been sourced from SAP and reconciled to the annual RIN amounts. UE's internal costing have been established so that reporting actual costs at the level in the CA RIN is achievable. A series of internal codes have been established enabling UE to allocate costs to the relevant RIN headings.

Volumes have been sourced from GIS except for maintenance poles that have been estimated. For this category data was not available and engineering judgement has been applied.

The number of lights maintained have been extracted from the annual RIN which in turn has been audited. For 2009 and 2010 this has been estimated based on the movement in light volumes for the 2011 to 2012 period. The reason it has been estimated is that reliable data is not available to UE.

Quality of services has been extracted from annual RIN submissions. For 2009 and 2010 these amounts have been estimated using an average of the 2011 to 2013 performance. For 2011 to 2013 actual data is available to be extracted from SAP based on internal codes established for these activities. For 2009 and 2010 data is not available due to the contracting arrangements in place at that time – no data was provided.

12.2. Cost metrics

Cost and unit data has been sourced from SAP. The average cost is cost divided by units.

13. Metering

13.1. Metering descriptor metric

Detailed description to provide abnnual data is provided below.

2009 meter counts is estimated from the meter count information stored in historical CIS+ data extract stored as part of 2010 sample test plan. Meter type information used to differentiate between various Asset Categories. Ue does not have information on 2008 meter volumes so it is not possible to do average of meter quantities.

2010 meter volumes reported in 2011 Annual RIN report was estimates. Also 2009 end of year meter volumes are estimates. We have simply used end of 2010 meter volumes in this report without averaging.

For 2011 to 2013 this data has been taken from the annual RINS which in turn has been extracted from SAP for type 4 meters and CIS for type 5 and 6 meters.

For 2011 to 2013 the following assumptions apply:

- Two single phase meters and time switch at one installation counted as one meter consistent with Annual RIN reports.
- We have included >160 MWh customers where United Energy is Responsible Person. Approximately 600 customers of 650K total population (~ 0.1%) belongs to >160 MWh category. As we could not separate these customers for all metering services, we have included these customers in scope.
- AMI Meters in CIS+ considered as type 4 as Type 6-5 transition is continuous process.

13.2. Cost metrics

Expenditure data has been reconciled to the annual RIN and has been audited as part of that process. This data is also consistent with AMI submissions. . The detailed data has been extracted from SAP costing systems to populate the required RIN headings. Each of the headings in the CA RIN is consistent with UE's internal; costing systems and therefore cost data is attributed to each of the headings. For 2009 and 2010 the cost data at the detailed level is considered to be estimated based on the contracting arrangements in place at that time.

The other metering category has been used to reconcile to the annual RIN where these costs were not disclosed at the disaggregated level described above.

- Meter purchases – this data is sourced from internal models from the UE AMI team and reconciles to submissions made to the AER.

- Meter testing – includes sample testing of direct connected meters, 100% testing of CT connected meters. CT inspections & admittance test also carried out as part of CT meter testing, sample testing of Current Transformers and excludes customer paid tests not included as they part of ACS. Total metering installation testing costs is sum of meter test and Current

Transformer test costs. Current Transformers testing costs not recorded by meter type. We have estimated costs split between meter type based on installation volumes reported in Table 4.2.1.

- Meter investigations – includes meter investigation service orders to Metering Specialist contractor for field investigation and revenue protection and police initiated drug raids. UE has total volumes however cost and quantity split for different meter types not available. These costs and quantity distributed between meter types based on 35:40:25. UE has not split these costs based on volume as meter investigation requirement is more for AMI Meters & Interval meters.

- Scheduled meter reading – as per SAP. Scheduled meter read costs not recorded by meter type. UE has estimated costs split between meter types based on installation volumes reported in Table 4.2.1 & per unit costs based on 2012 actuals.

- Special meter reading – as per SAP . These costs were available as single line item as sum of Type 5 & 6. Annual Finance RIN input has special meter reading Revenue information split across Type 5 and 6 metering for 2011 - 2013. Costs for Type 5 & 6 for 2011-13 are split based on the Revenue ratio. For years 2009 and 2010 Type 5 & 6 total costs are split based on the average special meter read unit cost rate proportioned by installed population of Type 5 & 6.

- New meter installations – as per SP. These volumes are not separated across meter type 4,5 & 6. UE has meter volume information from historical new connections split across meter type as part of internal budgetary preparation. Total volumes & costs split by the same ratio as reported in new connection report.

- Meter replacement – as per SAP. UE has estimated 2009-2011 volumes & cost from various internal budgeting files stored in network folders. Also, we have estimated Type 5 & 6 meter volumes as zero for 2012 and 2013 as practically all of the meter replacements are Type 4 AMI.

- Meter maintenance – as per SAP. UE has estimated Type 6 meter maintenance costs same for years 2009-2011 based on 2012 actual cost as complex metering installs only started in 2013. Year 2013 estimation is based on reduction in Type 6 meter volumes.

- Remote meter reading - Actual data Information obtained from UIQ (Utility IQ system is part of AMI remote polling system NMS) Historical interval data collection metrics report.

- Remote configuration - Actual data Information obtained from UIQ (Utility IQ system is part of AMI remote polling system NMS) report.

- Other categories – data have been obtained from SAP and the “other” category used to reconcile to total costs as reported to the AER in the annual RIN submission.

14. Ancillary Services – Fee Based Services

14.1. Cost metrics for fee-based services

Data has been sourced directly from the annual RIN.

Volume based data is sourced directly from SAP. When customers are invoiced for services requested the invoice and SAP data filed contains the units of work requested. UE can determine how many units of work are invoiced for and therefore can populate data of the CAN RIN

Expenditure for fee and quoted services is determined based on the volumes invoiced to those requesting the work as described above. The actual number of units (as determined above) is multiplied by the contract rate to determine the cost for the services provided.

15. Ancillary Services – Quoted Services

15.1. Cost metric for quoted services

Data has been sourced directly from the annual RIN.

Volume based data is sourced directly from SAP. When customers are invoiced for services requested the invoice and SAP data filed contains the units of work requested. UE can determine how many units of work are invoiced for and therefore can populate data of the CAN RIN

Expenditure for fee and quoted services is determined based on the volumes invoiced to those requesting the work as described above. The actual number of units (as determined above) is multiplied by the contract rate to determine the cost for the services provided.

16. Asset Age profile

16.1. Asset age profile

The three different methods utilised to calculate assets' economic lives are as follows:

Asset Types	Economic Life Calculation Method
Pole Top Structure, Pits & Pillars	Normal method via extracting Replacement Notifications from SAP
Indoor Circuit Breakers, Protection Relays	Asset failure data from Weibull model
All other assets	Accounting useful life based on depreciation method

Asset replacements have been captured in UE's SAP system via replacement notifications. The procedure utilised to calculate the assets' economic lives based on replacement notifications from SAP, is as follows:

1. Identify assets that have been replaced in the UE SAP system
2. Determine the corresponding equipment of the asset replacement notification
3. Determine the construction year of the asset
4. Calculate the age of the asset at replacement
5. Remove outliers
6. Classify each asset replacement into a RIN category
7. Calculate the mean economic life and standard deviation of the asset

The construction date of the asset is based on the installation date of the corresponding equipment the asset replacement notification is allocated against. Refer to the relevant UE asset class age profile procedure to obtain the equipment installation date.

For pits and pillars which have two possible asset class allocation, the construction year of the equipment was determined in the following order:

a. Use the construction year of the transformer if the notification was raised against a distribution transformer or distribution substation.
b. Use the construction year of the pole if the notification is raised against a pole.

Improvements have been recommended to capture better asset data in SAP and/or GIS.

Review the age at replacement for all replacements and identify outliers and the scenarios when these occur.

The following outliers had been removed in the calculation of the economic life for pole top structures only:

- If the calculated age at replacement ranges from 0 to 20 years, this was considered as an outlier and was removed. This was due to a separate notification being created retrospectively for the replacement of the pole top structure which was replaced in conjunction with the pole in an earlier notification.

- If the calculated age at replacement ranges from 50 to 100 years, this was considered as an outlier and was removed. This was due to notifications not being created when a pole top structure was replaced.

The following outlines the procedure utilised to calculate the mean life and standard deviation of these assets based on the asset failure data extracted from the Weibull Model:

1. Determine the age of the asset at replacement
2. Classify each asset replacement into a RIN category
3. Calculate the mean age and standard deviation of the asset

17. Maximum Demand at Network Level

17.1. Raw and weather corrected coincident MD at network level (summed at transmission connection)

This table consists of seven data categories.

- Raw network coincident maximum demand
- Date of the maximum demand
- Half hour time period of the maximum demand
- Whether the network is Summer or Winter peaking
- Embedded generation contribution
- Weather corrected 10% POE network coincident maximum demand
- Weather corrected 50% POE network coincident maximum demand

After each summer, UE Network Planning collects the actual demand data (half-hourly average summations of a set of wholesale boundary load NMIs) to identify the maximum coincident UE demand, date and time for that summer. Based on this information and the temperature sensitivity information available in the NIEIR forecast, 10% and 50% POE demands are estimated. Further, as part of the data provided to NIEIR to facilitate the forecasting process, the embedded generation contributions are captured.

A snap shot of the data is presented below.

UE System Summer Peak Demand MW - Historical & NIEIR Forecast Medium Economic Growth

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UNITED ENERGY

Year	UE Actual	UE Load Factor	Date/Time of MD (EST)	Avg Day Temp.	Actual PoE	Forecast at Actual PoE	Weather Corrected 10% PoE	Weather Corrected 90% PoE	Weather Corrected 50% PoE	50% PoE F'Cast Error	Corrected Load Factor
Year	MW	MW/MW		°C	%	MW	MW	MW	MW	%	MW/MW
1997	1352	0.57									
1998	1350	0.58									
1999	1404	0.57									
2000	1455	0.55									
2001	1564	0.55									
2002	1441	0.59		27.7	82%						
2003	1468	0.59		30.1	31%		1657		1519		0.57
2004	1646	0.55		30.1	31%	1663	1716	1450	1583	1.2%	0.57
2005	1572	0.57	Tue 01/03/2005 14:00	26.8	98%	1508	1878	1600	1739	-3.6%	0.52
2006	1649	0.57	Fri 24/02/2006 16:00	27.8	80%	1632	1903	1613	1758	-0.8%	0.53
2007	1750	0.54	Tue 16/01/2007 15:00	28.8	62%	1788	1948	1643	1795	2.3%	0.52
2008	1918	0.50	Mon 17/03/2008 16:00	29.7	47%	1893	2062	1749	1906	-1.1%	0.50
2009	2084	0.46	Thu 29/01/2009 13:00	35.0	4%	2066	2060	1746	1903	-0.7%	0.50
2010	2016	0.48	Mon 11/01/2010 16:00	31.3	22%	2044	2064	1743	1904	1.7%	0.51
2011	1962	0.49	Tue 01/02/2011 13:00	32.4	15%	2225	2173	1803	1988	3.2%	0.48
2012	1700	0.57	Tue 24/01/2012 16:00	27.7	82%	1953	2185	1868	2027	2.2%	0.48
2013	1982	0.48	Tue 12/03/2013 16:00	29.3	77%	1932	2284	1923	2104	-3.3%	0.45
2014	2066		Thu 16/01/2014 17:00	35.5	2%	2268	2237	1839	2038	-1.2%	

Figure 1: Extract of UE actual and weather corrected actual demands

- This spreadsheet provides the following data from summer 2004/05. The half hourly time interval reported is based on the Australian Eastern Standard Time (AEST).
- Actual network coincident maximum demand (MW): The maximum half-hourly average summations of a defined set of wholesale boundary load NMIs[1] for UE.
- Date of the MD: The date on which the maximum demand was recorded for the year between November of the previous calendar year through to March (inclusive), defining a full "summer" period.
- Time of the MD: The time the maximum demand was recorded on the date of the MD, based on Australian Eastern Standard Time (AEST), for the half-hour ending time.
- UE network experiences a "summer" peak. UE only reports on summer maximum demand because summer maximum demand is larger than the winter maximum demand.
- The embedded generation contribution at the coincident maximum demand is available in the annual data provided to NIEIR for forecasting and is obtained from actual half-hourly average summations of a defined set of wholesale boundary load NMIs[1] (for large embedded generators) at the date and time of the MD. All the embedded generators in the UE network are of non-scheduled category.
- Weather Corrected 10% POE network coincident maximum demand (MW): A formula in the above-mentioned spreadsheet that adjusts the actual maximum demand by the temperature sensitivity of the demand, based on the observed PoE temperature condition on the day of the MD and the 10% PoE. This value may sometimes be adjusted for other influencing factors such as school

holiday/industry shutdown period especially if the MD occurs between late-December and mid-January. Where this is done, an explanation is annotated. i.e.; the weather correction is done on the raw adjusted maximum demand.

- The temperature sensitivity of the demand is calculated based on the 10% and 90% POE forecasts prepared by NIEIR for that year. The difference between these two forecasts provides the expected change in demand for a change in POE from 10% to 90%. This relationship is assumed to be linear. The difference between the 10% POE and the actual POE is then multiplied by this factor to estimate the expected change from actual demand to the 10% POE demand. This figure is then added to the raw adjusted maximum demand to estimate the 10% POE demand.

- Weather Corrected 50% POE network coincident maximum demand (MW): A formula in the above-mentioned spreadsheet that adjusts the actual maximum demand by the temperature sensitivity of the demand, based on the observed PoE temperature condition on the day of the MD and the 50% PoE. This value may sometimes be adjusted for other influencing factors such as school holiday/industry shutdown period especially if the MD occurs between late-December and mid-January. Where this is done, an explanation is annotated. i.e.; the weather correction is done on the raw adjusted maximum demand.

- The temperature sensitivity of the demand is calculated based on the 10% and 90% POE forecasts prepared by NIEIR for that year. The difference between these two forecasts provides the expected change in demand for a change in POE from 10% to 90%. This relationship is assumed to be linear. The difference between the 50% POE and the actual POE is then multiplied by this factor to estimate the expected change from actual demand to the 50% POE demand. This figure is then added to the raw adjusted maximum demand to estimate the 50% POE demand.

18. Maximum Demand and Utilisation at Spatial Level

18.1. Non-coincident maximum demand

The Summer Cyclic Rating (SCR) rating in MVA is used to report the capacity of a zone substation. Note: There is no distinction between non-coincident and coincident values.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated with CA RIN requirements to extract the required information

Historical maximum demands (MW) at each zone substation were captured and recorded as part of the load forecasting process. These values have been adjusted for any applicable abnormalities which occurred within the period concerned.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

The actual raw demand in MW was extracted from OSI-PI (the data-warehouse for SCADA data) at the time of UE maximum demand. The timing information for UE maximum demand is reported as part of Table 5.3.1 (Section 6.2.1). If the extracted instantaneous demand value was greater than the raw actual non-coincident maximum demand in MW presented in Section 6.3.1.2, then the coincident maximum demand was set to the non-coincident maximum demand value. This type of mismatch can occasionally be seen due to a network abnormality at that time or as a result of spiky (instantaneous readings) load profile. Both these situations were duly treated when extracting the non-coincident maximum demand information after each summer. Therefore, limiting the coincident maximum demand to non-coincident maximum demand when a discrepancy exists is the assumption applied.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

Similar to historical maximum demands in MW, the reactive power demand in MVAr at each zone substation were captured and recorded as part of the load forecasting process. These values have been adjusted for any applicable abnormalities occurred within the period concerned. Those MW and MVAr values can be used to calculate the MVA demand and operating power factor at each zone substation.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

The operating power factor at non-coincident demand was calculated at each zone substation as discussed in Section 6.3.1.4. The same power factor was used to estimate the raw coincident maximum demand in MVA based on the raw maximum demand in MW extracted as discussed in Section 6.3.1.3.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

Date and time of the non-coincident maximum demand at each zone substation extracted and recorded as part of the load forecasting process.

The half hourly time interval reported is based on the Australian Eastern Standard Time (AEST). Given the OSI-PI data is recorded based on the Australian Eastern Daylight Time (AEDT), relevant adjustments are made to reconcile with AEST.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

The timing information for UE coincident maximum demand is reported as part of Table 5.3.1. The half hourly time interval reported is based on the Australian Eastern Standard Time (AEST).

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

- **Season of the maximum demand**

All the zone substation in UE supply area are summer peaking.

While extracting non-coincident maximum demand information as part of the load forecasting process; the embedded generation contributions at the maximum demand are recorded. This is presently applicable at only three zone substations.

- Dandenong zone substation – Dandenong hospital and CoGent generation
- Springvale South zone substation – Springvale and Clayton landfill generation
- Sorrento zone substation – Rye landfill generation

All these embedded generators are of non-scheduled category.

The impact solar generation is automatically captured in the process as a negative demand and no further treatment is required.

Therefore, where large embedded generators are connected, the actual transformer maximum demand is less by the amount of generation support provided by the embedded generation facility at the time of peak demand.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

- **Adjustments for embedded generation at the coincident maximum demand**

While extracting coincident maximum demand information, the embedded generation support at the time of UE peak was noted from PI and metering data. This is presently applicable at only three zone substations.

- Dandenong zone substation – Dandenong hospital and CoGent generation
- Springvale South zone substation – Springvale and Clayton landfill generation
- Sorrento zone substation – Rye landfill generation

All these embedded generators are of non-scheduled category.

The impact solar generation is automatically captured in the process as a negative demand and no further treatment is required.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

- **Weather corrected 10% POE non-coincident maximum demand (MW)**

Raw UE coincident maximum demand was captured after each summer. Based on this information and the temperature sensitivity information available in the NIEIR forecast, 10% and 50% POE demands are estimated.

This information will then be used to calculate two factors (10% POE and 50% POE) between the actual demand and the weather corrected demands. The 10% POE factor will be used to scale the raw non- coincident zone substation demands in MW to estimate the 10% POE weather corrected non–coincident maximum demands in MW.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

- **Weather corrected 10% POE coincident maximum demand (MW)**

The 10% POE factor will be used to scale the raw coincident zone substation demands in MW to estimate the 10% POE weather corrected coincident maximum demands in MW.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

- **Weather corrected 10% POE non-coincident maximum demand (MVA)**

The 10% POE factor will be used to scale the raw non-coincident zone substation demands in MVA to estimate the 10% POE weather corrected non–coincident maximum demands in MVA. For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

- **Weather corrected 10% POE coincident maximum demand (MVA)**

The 10% POE factor will be used to scale the raw coincident zone substation demands in MVA to estimate the 10% POE weather corrected coincident maximum demands in MVA.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

- **Weather corrected 50% POE non-coincident maximum demand (MW)**

The 50% POE factor will be used to scale the raw non-coincident zone substation demands in MW to estimate the 50% POE weather corrected non–coincident maximum demands in MW.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

- **Weather corrected 50% POE coincident maximum demand (MW)**

The 50% POE factor will be used to scale the raw coincident zone substation demands in MW to estimate the 50% POE weather corrected coincident maximum demands in MW.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

- **Weather corrected 50% POE non-coincident maximum demand (MVA)**

The 50% POE factor will be used to scale the raw non-coincident zone substation demands in MVA to estimate the 50% POE weather corrected non–coincident maximum demands in MVA.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

- **Weather corrected 50% POE coincident maximum demand (MVA)**

The 50% POE factor will be used to scale the raw coincident zone substation demands in MVA to estimate the 50% POE weather corrected coincident maximum demands in MVA.

For the purpose of populating the first benchmark RIN in Nov 2013, a copy of the 2012/13 Load Forecast spread sheet has been updated to extract relevant information. The same spread sheet has further been populated to assist in extracting data for CA RIN.

19. Sustained interruptions to Supply

Information provided for the Sustained Interruptions to Supply Table 6.3 in Category Analysis RIN for the period 1 July 2008 – Dec 31 2013 have the following basis.

Calculation of MED

For 2011 to 2013 the MED calculation is based on an average of the last five years data consistent with the STPIS requirement – this is actual data. For 2008 to 2010 the 2012 MED thresh hold was applied - this is estimated data.

Planned

Period 1: 1 Jan 2008 to 31st December 2010

UED Planned/Unplanned Outage History Access Database File (actuals from hand back information provided by Jemena in 2011) this information was used to produce the Annual ESC submission for the period up to Dec 2010. Planned information was from this source data.

The reason for interruption in each case is identified as “Planned” and as a consequence the detailed reason for interruption is left Blank.

Period 2: 1 Jan 2011 to 31st Dec 2011

The 2011 “Planned” information was sourced from the 2011 RIN provided to AER.

The “Reason for Interruption” is planned therefore the detailed reason is Blank.

Period 3: 1 Jan 2012 to 31st Dec 2013

Information was sourced from outage data sheets derived from DMS PMART files. The “Reason for Interruption” is planned therefore the detailed reason is Blank.

Unplanned

Period 1: 1 Jan 2008 to 31st December 2010

UED Planned/Unplanned Outage History Access Database File (was used to produce the Annual ESC submission for the period up to Dec 2010.

The “Reason for Interruption” is determined by:

- identifying the primary cause from the UED Planned/Unplanned Outage History Access Database File

- matching the primary cause against the appropriate "Reason for Interruption" from AER listed reasons from **Table 1 - AER CA RIN Tab 6.3 Table Extract** against **Table 2 – UE Primary Cause to AER CA RIN RFI.**

The "Detailed Reason for Interruption" is determined by:

- identifying the primary cause from the UED Planned/Unplanned Outage History Access Database File
- matching the primary cause against the appropriate "Reason for Interruption" from AER listed reasons from **Table 1 - AER CA RIN Tab 6.3 Table Extract** against **Table 2 – UE Primary Cause to AER CA RIN RFI**
- If the "Reason for Interruption" is identified as an "Asset Failure" then **Table 3 – UE Asset Failure Trouble Level to AER Detailed Reason for Interruption** is then used to identify the appropriate reason

Period 2: 1 Jan 2011 to 31st December 2013

Information is sourced from outage data sheets derived from DMS PMART files.

The "Reason for Interruption" is determined by:

- identifying the primary cause from the UED Planned/Unplanned Outage History Access Database File
- matching the primary cause against the appropriate "Reason for Interruption" from AER listed reasons from **Table 1 - AER CA RIN Tab 6.3 Table Extract** against **Table 2 – UE Primary Cause to AER CA RIN RFI**

The "Detailed Reason for Interruption" is determined by:

- identifying the primary cause from the UED Planned/Unplanned Outage History Access Database File

- matching the primary cause against the appropriate "Reason for Interruption" from AER listed reasons from **Table 1 - AER CA RIN Tab 6.3 Table Extract** against by using **Table 2 – UE Primary Cause to AER CA RIN RFI**

- If the "Reason for Interruption" is identified as an "Asset Failure" then **Table 3 – UE Asset Failure Trouble Level to AER Detailed Reason for Interruption** is used to identify the appropriate reason

Table 1 - AER CA RIN Tab 6.3 Table Extract

Reason for interruption	Detailed reason for interruption
Animal	Animal impact
	Animal nesting/burrowing, etc and other
	Other
Asset failure	LV
	Distribution substation
	HV
	Zone substation
	Subtransmission
Other	insert description of 'other'
Overloads	
Planned	
Network business	Network error
	Switching and protection error
Third party	Fire
	Other
	Dig-in
	Unauthorised access
	Vehicle impact
Unknown	Unknown
Vegetation	Blow-in/Fall-in - NSP responsibility
	Grow-in - NSP responsibility
	Blow-in/Fall-in - Other responsible party
	Grow-in - Other responsible party
Weather	
2 - STPIS Exclusion (3.3)(a)	
3 - STPIS Exclusion (3.3)(a)	
4 - STPIS Exclusion (3.3)(a)	
5 - STPIS Exclusion (3.3)(a)	
6 - STPIS Exclusion (3.3)(a)	
7 - STPIS Exclusion (3.3)(a)	

Table 2 – UE Primary Cause to AER CA RIN RFI

Primary Cause	Reason For Interruption	Detailed Reason for interruption
Animal - Probable Animal	Animal	Animal impact
Animal - Bird	Animal	Animal impact
UE Asset - Rot In X-Arm	Asset failure	
Other - Junct Box or Mains Burnt	Asset failure	
n/a	unknown	Unknown
Other - Connection Loose	Asset failure	
Elements - Deterioration	Weather	-
Weather - Lightning	Weather	-
Tree - Tree/Branch Oth Resp	Vegetation	Grow-in - Other responsible party
UE Asset - Elec Failure	Asset failure	
Tree - Probable Tree/Branch	Vegetation	Grow-in - Other responsible party
Misc - No Identified Cause	unknown	Unknown
UE Asset - Underground Fault	Asset failure	
Service - Elec Failure	Asset failure	
Animal - Other Than Bird	Animal	Animal impact
Vehicle Damage	Third party	Vehicle impact
Person - UG Cable Dug Up by Oth	Third party	Dig-in
Tree - Tree/Branch Priv Resp	Vegetation	Grow-in - Other responsible party
Misc - Vandalism	Third party	Other
Misc - Retailer Error	Third party	Other
Person - Other Human Error	Third party	Other
Misc - Unclassifiable	unknown	Unknown
Elements - Pollution (Dust/Salt)	Weather	-
Other - Verified Volt Complaint	Asset failure	
Other - Electrical Overload	Overloads	-
Service - Tree	Vegetation	Grow-in
Meter - Time Switch	Asset failure	
Meter - Electronic/Mech	Asset failure	
UE Asset - Clashing	Asset failure	
UE Asset - Mech Failure	Asset failure	
Tree - Other Tree Fell/Trim	Vegetation	Blow-in/Fall-in
UE Asset - Corrosion	Asset failure	
Service - Mech Failure	Asset failure	
Fire - UE Asset	Asset failure	
Other - Broken Neutral	Asset failure	
Part Of Planned Outage	Planned	-
Weather - Flood Water	Weather	-

Weather - Probable High Winds	Weather	-
Tree - Tree/Branch UE Resp	Vegetation	Blow-in/Fall-in
Service - Vehicle Inside Prop	Third party	Vehicle impact
UE Asset - Incorrect Volt/Tap	Asset failure	
Service - Vehicle Outside Prop	Third party	Vehicle impact
vehicle	Third party	Vehicle impact
Street Light	Asset failure	
Misc - Other Authorities Assets	Third party	Other
Animal - Probable Bird	Animal	Animal impact
ZS Oth Pri Pl - Elec Failure	Asset failure	
Weather - Probable Lightning	Weather	-
UE Asset - Mech Damage	Asset failure	
lightning	Weather	-
overload	Overloads	-
Person - Disc By Mistake	Network business	Switching and protection error
Weather - High Winds	Weather	-
Tree - Bark	Vegetation	Blow-in/Fall-in
UE Asset - Breakage incl SSS	Asset failure	
Fire - Other or External Fire	Third party	Fire
ZS Prot - Prot Maloperation	Network business	Switching and protection error
Electric Shock	Third party	Unauthorised access
Person - Switching Error	Network business	Switching and protection error
Tree - UE Tree Fell/Trim	Vegetation	Blow-in/Fall-in
ZS Trans - Winding Failure	Asset failure	
ZS Oth Pri Pl - Mech Damage	Asset failure	
ok	unknown	Unknown
Other - Secondary Damage	Asset failure	
Service - Other Cable System	Asset failure	
UE Asset - Termites In X-Arm	Asset failure	
Fire - Customer Installation	Third party	Fire
Person - Crew Out (Un-notified)	Planned	-
ZS Oth Sec Equ - Ctrl Sys Fail	Network business	Switching and protection error
ZS Oth Pri Pl - Mech Failure	Asset failure	
Misc - No Go Zone	other	Misc - No Go Zone
UE Asset - Load Shedding	Overloads	-
ZS CB - Burnt Contacts	Asset failure	
ZS CB - Slow Operation	Asset failure	
cust	Asset failure	
Other - Verified TVI Complaint	Asset failure	

conn	Asset failure	
ZS CB - Insulation Failure	Asset failure	
Other - Verified TVI Complaint	Asset failure	
reconn	Asset failure	
ZS Prot - Incorrect Settings	Network business	Switching and protection error
tree	Vegetation	Blow-in/Fall-in
weather	Weather	-
no	unknown	Unknown
other	unknown	Unknown
UE Asset - Brown Out	Asset failure	
ZS Prot - Incorrect Prot Setting	Network business	Switching and protection error

Table 3 – UE Asset Failure Trouble Level to AER Detailed Reason for Interruption

Asset Failure Trouble Level	Detailed reason for interuption
FD	HV
ACR	HV
PR	LV
DS	Distribution substation
no sustained	HV
LF	HV
LV	LV
SubT	Subtransmission
ZS	Zone substation