Economic Benchmarking

RIN – Basis of Preparation

CONFIDENTIAL

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Economic Benchmarking Regulatory Information Notice

Basis of Preparation

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1. Introduction

As per the AER letter dated the 28th November 2013, 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 UE 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 provides UE’s Basis of Preparation in accordance with the Regulatory Information Notice.

Having regard to the notice, this submission (including the Excel templates and the Statutory Declaration) has been prepared so that in all material aspects it is in accordance with the requirements of the Notice and true and accurate.

2. Revenue

2.1. Revenue grouping by chargeable quantity

2.1.1. Standard Control Services

The values for each year in this table have been derived from the Regulatory Accounting Statements and the Annual RINs. This is consistent with the requirements of the Economic RIN instructions. This data has previously been audited and representative of the reported revenue for each year. The data from 2013 has been reviewed by EY.

The revenue group charge data for the period 2006-2009 has been obtained from the CIS billing data file. For the period 2010-2013 the data is derived from the monthly consolidated billing file (CIS+SAP). This data (in particular the final three months of each calendar year) contains accrued data based on a quarterly billing cycle. This accrual is generated from the billing engine based on complex algorithms previously audited.

As the billing files incorporate prior period adjustments there will be some small variation when compared to the RIN Reported revenues attributed to timing of cancels and rebills etc. Therefore the billing data, pertaining to energy revenue, has been scaled to the Annual RIN and Regulatory Accounting Statements reported energy revenue. As such, this treatment involves an element of estimation. That is, we allocate the difference that come about between the reported and the billed linear data across the different tariffs. To be specific, any residual differences (very minor) have been allocated to the anytime rate category as it represents the largest by volume.

The final result is billing charge data scaled to meet the RIN revenue as indicated in annual Regulatory Accounts and RIN Templates from 2006-2012. 2013 data represents reported billing charge data as at February 2014.

A reconciliation of the economic and annual RIN statements is provided in the table below:

Table 2.1: Reconciliation to annual reported amounts ($m MOD)

Year	Economic RIN	Gross revenue	Less grid fees	Total Reported
2006	283.1	359.0	75.9	283.1
2007	295.1	375.9	80.8	295.1
2008	297.7	377.9	80.2	297.7
2009	295.1	379.9	84.8	295.1
2010	299.9	394.6	94.7	299.9
2011	307.3	403.4	96.1	307.3
2012	323.9	447.2	123.3	323.9
2013	343.0	449.3	106.3	343.0

Note: For years 2006 to 2010 refer regulatory accounting statement DR – Demand and Revenue. For 2011 to 2013 refer Annual RIN, template 20 table 1.

The table below provides a mapping of UE tariff components to economic RIN categories.

Table 2.2: Mapping Tariff Components to RIN Categories

Economic RIN Category	UE Tariff Component
DREV0101 – Revenue from Fixed Customer Charges	FXD DED, FXD HV-KVA, FXD HV-KVA-HOT, FXD KW-TOU, FXD KW-TOU-HOT, FXD L1, FXD L2,FXD L2-KVA, FXD L2-KVA-HOT, FXD M1, FXD M25, FXD M27, FXD S1, FXD S1WET, FXD S2, FXD ST22-KVA
DREV0102 – Revenue from Energy Delivery charges where time of use is not a determinant	EGY1RB1 L1, EGY1RB2 M1, EGY1RB3 S1
DREV0103 – Revenue from On–Peak Energy Delivery charges	EGYPK HV-KVA, EGYPK HV-KVA-HOT, EGYPK KW-TOU, EGYPK KW-TOU-HOT, EGYPK L2, EGYPK L2-KVA, EGYPK L2-KVA-HOT, EGYPK M25, EGYPK M27, EGYPK S1WET, EGYPK S2, EGYPK ST22-KVA,
DREV0105 – Revenue from Off–Peak Energy Delivery charges (excluding hot water and other DED)	EGYOPK HV-KVA, EGYOPK HV-KVA-HOT, EGYOPK KW-TOU, EGYOPK KW-TOU-HOT, EGYOPK L2, EGYOPK L2-KVA, EGYOPK L2-KVA-HOT, EGYOPK M25, EGYOPK M27, EGYOPK S1WET, EGYOPK S2, EGYOPK ST22-KVA,
DREV0106 – Revenue from controlled load customer charges	EGYOPK DED
DREV0107 – Revenue from unmetered supplies	EGYOPK UNM, EGYPK UNM
DREV0109 – Revenue from Measured Maximum Demand charges	DMNRLN HV-KVA, DMNRLN HV-KVA-HOT, DMNRLN L2-KVA, DMNRLN L2-KVA-HOT, DMNRLN ST22-KVA, DMNSMR HV-KVA, DMNSMR HV-KVA-HOT, DMNSMR KW-TOU, DMNSMR KW-TOU-HOT, DMNSMR L2-KVA, DMNSMR L2-KVA-HOT, DMNSMR ST22-KVA

2.1.2. Alternative Control Services

The values for each year in this table have been derived from the Regulatory Accounting Statements and Annual RINs. This data has previously been audited and representative of the reported revenue for each year. This data is based on actual invoices raised (not cash received). Minimal accruals are raised for alternative control services revenue.

Table 2.3 Reconciliation to Annual Reported Amounts ($m MOD)

Year	Economic RIN	Annual RIN
2006	13.0	13.0
2007	14.7	14.7

2008	15.5	15.5
2009	15.3	15.3
2010	16.6	16.6
2011	18.6	18.6
2012	19.1	19.1
2013	17.4	17.4

Note1: For years 2006 to 2010 refer regulatory accounting statement ES – Excluded Services.

Note 2: For 2011 to 2013 refer Annual RIN template 19.

The table below provides a mapping of UE tariffs to economic RIN categories.

Table 2.4: Mapping Tariff Codes to RIN Categories

Economic RIN Category	Alternative Control Service
Metering charges	Metering, special reads, remote meter-reconfiguration, meter Investigations
Connection charges	New Connections, Connections, U/G Services at request of 3rd party, Service Trucks, Connections/Disconnections, De-energisation of Existing Customers, Energisation of Existing Customers, Re-test of type 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh, Wasted attendance - not DNSP fault, Routine connections - customers below 100 amps Covering of low voltage mains for safety reasons, Routine connections for customers > 100amps, Temporary Supplies Services
Public lighting charges	Public Lighting (efficient and non-efficient)
Other services	Other

2.2. Revenue grouping by Customer type or class

2.2.1. Standard Control Services

Revenue by customer category has been derived from audited RIN submissions and Annual Regulatory Accounting Statements for the period 2006-2013. This information is derived at the time of reporting from the Q-report which is extracted from CIS and SAP (AMI-SAP from 2010).

2006-2013 revenue by tariff type has been allocated against the appropriate customer class defined in the table. Total revenue equals the RIN templates.

Table 2.5: Mapping Tariff Codes to Customer location

Tariff by customer type	UE Tariff Class
Revenue from residential Customers	DED (all tariff classes), S1, S1WET, S2, TOD, TOD9
Revenue from non-residential customers not on demand tariffs	L1, L2, M1, M25, M27
Revenue from non-residential low voltage demand tariff customers	KW-TOU, KW-TOU-H, L2-KVA, L2-KVA-H, TOU
Revenue from non-residential high voltage demand tariff customers	HV-KVA, HV-KVA-H, ST22-KVA
Revenue from unmetered supplies	UNM

2.2.2. Alternative Control Services

All ACS service have been allocated to revenue from other customers. UE systems are unable to determine a more detailed breakdown consistent with the headings provided in the RIN.

2.3. Revenue (penalties) allowed (deducted) through incentive schemes

2.3.1. Standard Control Services

The values for each year in this table have been derived from the respective final decisions.

EBSS

For 2006 to 2010 the ECM amount has been applied. Refer table 10.1 of that final decision (see link below). Escalation has been applied to bring that decision from real 2004 values to money of the day.

http://www.royalcommission.vic.gov.au/getdoc/d09c58ae-4770-4cae-9435-586148b53398/PAL.019.001.0636

For 2011 to 2013 the EBSS scheme was zero. Refer table 13.6 of the AER Final decision (see link below)

http://www.aer.gov.au/sites/default/files/Victorian%20distribution%20determination%20final%20decision%202011-2015%20%2829%20October%202010%29_3.pdf

STPIS

For 2006 to 20120 the values are based on performance for the years 2004 to 2008. The annual tariff submissions for 2006 to 2010 that were approved included a S_t component that reflected the amounts included for the Victorian S factor scheme. The S_t component is provided below:

Table 2.6: Extract of approved S_t component from annual tariff reports

	2006	2007	2008	2009	2010
S_t component	0.215%	-0.500%	0.000%	-3.050%	1.352%

The percentages in the table above have been applied to the the revenue reported on that year to determine the amount included in this table.

For 2011 and 2012 the values are zero. The new scheme only has a revenue effect in 2013 based on 2011 actual performance. Performance for 2012 will be included in the 2014 year.

For 2013 the AER approved 1.464% in the annual tariff variation process. Refer table 6.1 of the link below:

http://www.aer.gov.au/sites/default/files/United%20Energy%20-%20Approved%20annual%20pricing%20proposal%202013.pdf

F-Factor

F- factor is zero up until 2013. The scheme began in 2012 and the first year it affects revenue will be 2014.

S-factor true up

The values have been sourced from the AER's 2011 to 2015 final decision, appeal and change to Legislation (see link below). Escalation has been applied to the decision to bring the values to money of the day.

http://www.aer.gov.au/sites/default/files/United%20Energy%20distribution%20determination%20amended%20in%20accordance%20with%20the%20orders%20of%20the%20Tribunal%20-%2028%20September%202012_2.pdf

2.3.2. Alternative Control Services

Incentive schemes do not apply for this category.

3. Opex

3.1. Opex categories

3.1.1. Current opex categories and cost allocations

Since 2011 there has been a change in the Opex categories under which costs have been reported to the AER compared to the 2006-2010. UE's cost allocation methodology however has not changed.

3.1.2. Historical Opex categories and cost allocations

The values in this table are actual and have been derived from the submitted data in the Annual Regulatory Accounts and the Annual RINs.

Reconciliations are provided below:

Table 3.1: Standard Control Services reconciliation ($m MOD)

Year	Economic RIN	Operating Cost reported	Maintenance Cost reported	Total Reported
2006	83.2	57.3	25.9	83.2
2007	81.5	56.7	24.7	81.5
2008	85.4	58.4	27.1	85.4
2009	89.0	72.0	17.1	89.0
2010	96.1	71.5	24.6	96.1
2011	122.0	84.4	37.6	122.0
2012	126.5	71.4	55.1	126.5
2013	116.2	67.6	48.5	116.2

Note 1: For years 2006 to 2010 refer regulatory accounting statements AA – Operating & MA - Maintenance Activities. For 2011 to 2013 refer Annual RIN template 12.Operating Costs & 11.Maintenance Costs.

Note 2: Regulatory Accounts 2009 - Metering RBPC ($1.08m) incorrectly allocated in the SCS maintenance. This has been removed from the opex calculation.

Note 3: RIN 2012 - Debt raising costs ($3.8m) incorrectly allocated in SCS opex. This has been removed from the opex calculation.

Table 3.2: Alternative Control Services reconciliation ($m MOD)

Year	Economic RIN	Operating Cost reported	Maintenance Cost reported	Total reported
2006	8.7	4.3	4.5	8.7
2007	10.5	5.8	4.7	10.5

2008	10.9	5.8	5.1	11.0
2009	10.8	7.3	0.0	7.3
2010	11.9	7.7	4.2	11.9
2011	10.1	4.9	5.2	10.1
2012	12.1	7.2	4.9	12.1
2013	11.9	6.5	5.4	11.9

Note: For years 2006 to 2010 refer regulatory accounting statements MA - Maintenance & AA – Operating Activities. For 2011 to 2013 refer Annual RIN template 11.Maintenance Costs & 12.Operating Costs

3.2. Opex consistency

3.2.1. Opex consistency - current cost allocation approach

Please see explanation in 3.1.1

3.2.2. Opex consistency - historical cost allocation approach

The mapping to the Standard Control Services and Alternative Control Services categories are as per the AER's Instructions and Definitions. Additionally, UE is only reporting Opex for Network Services under Standard Control Services.

Standard Control

- Network services

All standard control opex costs are allocated to this heading unless allocated to a heading below.

- Metering

There are no standard control metering costs

- Connection services

There are no standard control connection services costs

- Public lighting

There are no standard control public lighting costs

- Easement levy

There are no standard control easement levy costs

- Transmission connection point planning

There are no standard control transmission connection point planning costs

Alternative Control

- Network services
- Metering
- Connection services

- Public lighting
- Easement levy
- Transmission connection point planning

The Alternative Control data has been mapped to the relevant headings.

3.3. Provisions

The opex provisions represented in the table are derived from the submitted data in the Annual Regulatory Accounts (refer schedule PA – Provisions) and the Annual RINs (refer template 16.Provisions). UE does not have Capex provisions.

3.4. Opex for high voltage customers

The values in this table have been estimated.

UE has a series of financial work break down costing structures that represent maintenance on distribution transformers for those asset owned by UE. For 2013 the expenditure against these codes total approximately $3.2m. UE has approximately 3,700 pieces of equipment that it maintains on a three year cycle. Therefore the cost of each piece $2,650 per annum. UE has used this cost per customer and applied this amount to previous years and adjusted for inflation for each year. This data has been sourced from UE's SAP system.

4. Assets

4.1. Regulatory Asset Base Values

The data in this table is the sum of the RAB variables.

Network Services

UE has deducted the value of services from the standard control asset base as its basis of populating this template. This only affects asset classes:

- Overhead network <33kv
- Underground network <33kv

The value of the services asset component has been determined on the basis as that described in section 4.2.

Additionally UE has deemed that the metering assets that are not part of the AMI RAB but which are currently part of the UE's existing RAB - are also excluded from the Network Services RAB.

Standard Control Services

This template has been completed in a number of stages.

- Stage one – ensure closing 2010 balance equals AER final decision
- Stage two – use Annual RIN data to populate from 2011 onwards

Table 4.1: Reconciliation between the Economic RIN and the AER approved RFM model ($m MOD)

	2006	2007	2008	2009	2010
Economic RIN	1,224.3	1,248.4	1,244.7	1,325.6	1,380.2
AER RFM model	1,280.1	1,309.8	1,310.9	1,399.2	1,380.2
Variance	**(55.8)**	**(61.4)**	**(66.2)**	**(73.6)**	**0.0**
Represented by:					
2005 net capex true up allocated to 2006 in EB rather than 2010 closing	(51.1)	0.0	0.0	0.0	0.0
Compound return allocated to each in EB rather than closing	(4.7)	(5.6)	(4.8)	(7.4)	0.0
Prior period	0.0	(55.8)	(61.4)	(66.2)	0.0
Total	**(55.8)**	**(61.4)**	**(66.2)**	**(73.6)**	**0.0**

Table 4.2a: Reconciliation of Net Capex from Regulatory Accounts 2006 - 2010 ($m MOD)

Year	EB RIN	Gross Capex	Less Customer Contributions	Less Disposals	Reported Net Capex	Less. Compounded Return on Difference from the previous period	Roll Forward Model Net Capex
2006	**82.2**	102.1	(12.1)	(3.2)	**86.8**	(4.7)	**82.2**
2007	**71.9**	95.5	(17.5)	(0.5)	**77.5**	(5.6)	**71.9**
2008	**75.5**	93.5	(12.9)	(0.3)	**80.3**	(4.8)	**75.5**
2009	**107.9**	128.5	(12.8)	(0.4)	**115.3**	(7.4)	**107.9**
2010	**119.5**	129.8	(4.9)	(0.0)	**124.9**	(5.3)	**119.5**

Table 4.2b: Reconciliation of Net Capex from Annual RINs 2011 - 2013 ($m MOD)

Year	EB RIN	Gross Capex	Less Customer Contributions	Less Disposals	Reported Net Capex	Add. WACC uplift	Roll Forward Model Net Capex
2011	**179.2**	185.9	(14.6)	(0.2)	**171.1**	8.1	**179.2**
2012	**196.5**	205.3	(18.1)	(0.3)	**186.9**	9.6	**196.5**
2013	**196.5**	192.1	(14.9)	(0.2)	**177.0**	7.7	**184.7**

Alternative Control Services

The Public Lighting RAB represented here is the final decision till 2010 and has been updated for actuals as per from 2011 onwards.

4.2. Total Asset Roll Forward

Standard Control

During 2011 Ernst and Young prepared a report for UE on the valuation of specified assets for insurance purposes. The effective date of the valuation is 31 March 2011. The insurance valuation itemises UE's asset to a detailed asset class level. The valuation percentages are contained in the table below:

Table 4.3: UE Asset Class allocation as a % of EB RIN Categories

UE Asset Class	%	EB RIN Template 4 categories
Network Overhead Conductor Low Voltage	11.75%	For overhead network assets less than 33kV:

Network Overhead Conductor High Voltage	7.71%	For overhead network assets 33kV and above:
Network Overhead Conductor Sub Transmission	2.65%	For overhead network assets 33kV and above:
Network Overhead Service Cable	2.80%	For overhead network assets less than 33kV:
	0.08%	For overhead network assets less than 33kV:
Network Pole Staking	0.27%	For overhead network assets less than 33kV:
	0.01%	For overhead network assets less than 33kV:
Network Pole Low Voltage	14.46%	For overhead network assets less than 33kV:
Network Pole High Voltage	16.61%	For overhead network assets 33kV and above:
Network Pole Sub transmission	2.66%	For overhead network assets 33kV and above:
Network Zone Sub Equipment	3.01%	Zone substations and transformers
	4.52%	Zone substations and transformers
Network Substation and Transformer	4.57%	Zone substations and transformers
	6.86%	Zone substations and transformers
Network Underground Cable Low Voltage	9.78%	For underground network assets less than 33kV:
	1.05%	For underground network assets less than 33kV:
	4.70%	For underground network assets less than 33kV:
	0.01%	For underground network assets less than 33kV:
Network Underground Cable High Voltage	6.50%	For underground network assets 33kV and above:
Total	**100.00%**	

UE has relied on the EY report and the percentages in the table above to allocate the asset base for the 2006 to 2010 period. UE has allocated capital expenditure for the 2011 to 2013 period on the following basis

Table 4.4: Mapping UE Capital Category to EB RIN Category

UE Capital Category	EB RIN
Sub transmission	Overhead network assets 33kV and above (wires and towers / poles etc)
	Underground network assets 33kV and above(cables, ducts etc)
	Zone substations and transformers
Distribution	Underground network assets less than 33kV (cables)
	Overhead network assets less than 33kV (wires and poles)
	Distribution substations including transformers
Metering	Meters
SCADA/Network control	“Other” assets with long lives
Non-network general assets - IT	“Other” assets with short lives
Non-network general assets - Other	“Other” assets with long lives
Public lighting	ACS RAB

Alternative Control Services

The values are based on reported numbers and the final decision as per the worksheets.

4.3. Total disaggregated RAB asset values

This the Average RAB values as per the AER document “Economic benchmarking RIN for distribution network service providers – Instructions and Definitions”

4.4. Asset Lives – Tables 4.4.1 & 4.4.2

The assets lives are based on the same methodology in used in the AER final decision for the 2011 to 2015 pricing proposal.

5. Operational Data

5.1. Energy Delivery

5.1.1. Energy grouping - delivery by chargeable quantity

The energy data reported in this table 5.1.1 (Variables DOPED0201 – DOPED0206) are based on actual data sourced from the annual Regulatory Accounts and RINs. A detail explanation is of how the energy is sourced and reported in the requested format is provided for each of the tables below.

DOPED0201 to DOPED0206 - This is actual data sourced straight from CIS/SAP Billing System Data. This information is derived at the time of reporting from the Q-report which is extracted from CIS and SAP (AMI-SAP from 2010). There are no estimations or scaling calculations as the energy data has been captured for defined time periods and is aggregated up to be presented as part of annual Regulatory Accounts and RIN energy volumes. UE did not capture energy at shoulder times until 2010. The totals therefore reconcile to table 5.1.

5.1.2. Energy - received from TNSP and other DNSPs by time of receipt

Data relating to energy received from TNSP and other DNSPs has been sourced from Interval Metering System and billing data as part of the DLF Spread sheet. The data is not currently captured in the form of the Off-peak, peak and shoulder. The data covering the period 2006-2012 has been reconciled to what has been the previously reporting reported to the AER.

DOPED0301 - Information not available in historical years, set to zero for first benchmark RIN, will be collected in future as part of DLF process

DOPED0302 - Information not available in historical years, set to zero for first benchmark RIN, will be collected in future as part of DLF process

DOPED0303 - Information not available in historical years, set to zero for first benchmark RIN, will be collected in future as part of DLF process

DOPED0304 - Information sourced from IMS/DLF Spread sheet. It is actual data, calculated as the Sum of “Energy obtained from transmission connections” + “Energy obtained from other distributors” in DLF spread sheet.

5.1.3. Energy - received into DNSP system from embedded generation by time of receipt

Energy data relating to embedded generation is captured in the Interval Metering System. This data is not captured in the disaggregated form requested in the table. The data covering the period 2006-2012 has been reconciled to what has been previously reported to the AER.

DOPED0401 - Information not available in historical years, set to zero for first benchmark RIN, will be collected in future as part of DLF process

DOPED0402 - Information not available in historical years, set to zero for first benchmark RIN, will be collected in future as part of DLF process

DOPED0403 - Information not available in historical years, set to zero for first benchmark RIN, will be collected in future as part of DLF process

DOPED0404 – This data is sourced from the IMS and Billing data as part of the DLF Spread sheet. It is actual data, calculated as the sum of “individually gross export metered IMS large generators” listed in the DLF calculation spread sheet.

5.1.4. Energy grouping - customer type or class

Energy by customer category has been derived from audited RIN submissions for the period 2006-2013. Mappings of tariffs are provided below.

DOPED0501 – This is actual data sourced straight from CIS/SAP Billing Data broken down by tariff categories. This data is then split into the requested AER customer categories. For this item, the tariff categories of DED, S1, S1WET, S2, TOD, TOD9 were summed together.

DOPED0502 – This is actual data sourced straight from CIS/SAP Billing Data broken down by tariff categories. This data is then split into the requested AER customer categories. For this item, the tariff categories are L1, L2, M1, M25, and M27 were summed together.

DOPED0503 – This is actual data sourced straight from CIS/SAP Billing Data broken down by tariff categories. This data is then split into the requested AER customer categories. For this item, the tariff categories are KW-TOU, KW-TOU-H, L2-KVA, L2-KVA-H, TOU were summed together.

DOPED0504 – This is actual data sourced straight from CIS/SAP Billing Data broken down by tariff categories. This data is then split into the requested AER customer categories. For this item, the tariff categories are HV-KVA, HV-KVA-H, and ST22-KVA were summed together.

DOPED0505 – This is actual data sourced straight from CIS/SAP Billing Data broken down by tariff categories. The amount in the tariff categories are then mapped into the requested AER customer categories. For this item, the tariff category is UNM were summed together.

As mention in the section above, the data is derived at the time of reporting from the Q-report which is extracted from CIS and SAP (AMI-SAP from 2010).

5.2. Customer Numbers

5.2.1. Distribution customer numbers by customer type or class

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.

The estimation and logic of calculating these values is explained in each of the requirements below.

DOPCN0101 – This is a combination of actual and estimated data that is sourced from the CIS/SAP Billing System. The estimated component is the growth rate of residential customers, and is based on the assumption that past historical growth rates are an approximate indicator of future growth. The calculation for the data is the residential customers from the data multiplied by a calibration factor (which again is based on historical growth rates applied to monthly customer data).

DOPCN0102 - This is actual data, with the figures sourced directly from the CIS/SAP Billing System

DOPCN0103 - This is actual data, with the figures sourced directly from the CIS/SAP Billing System

DOPCN0104 - This is actual data, with the figures sourced directly from the CIS/SAP Billing System

DOPCN0105 - This is actual data, with the figures sourced directly from the CIS/SAP Billing System

DOPCN0106 – There are no other customers – all are able to be allocated to the categories above.

5.2.2. Distribution customer numbers by location on the network

Distribution customers by location have been obtained by sourcing the customer data as described above.

DOPCN0201 – No customers in this region.

DOPCN0202 – For 2011 to 2013 the data is as per the annual RIN. For 2010 & 2009 it is as per the ESC compliance submissions. From 2006 to 2008 it is as per what has been reported in the EDPR 2011 RIN submission.

DOPCN0203 - For 2011 to 2013 the data is as per the annual RIN. For 2010 & 2009 it is as per the ESC compliance submissions. From 2006 to 2008 it is as per what has been reported in the EDPR 2011 RIN submission.

DOPCN0204 – No customers in this region.

5.3. System demand

5.3.1. Annual system maximum demand characteristics at the zone substation level – MW measure

DOPSD0101 – This is actual information sourced from the field that directly interfaces with SCADA data.

DOPSD0102 – This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 10% POE value/Actual) * Zone substation summation (DOPSD0101). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at non-coincident demand.

DOPSD0103 – This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 50% POE value/Actual) * Zone substation summation (DOPSD0101). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at non-coincident demand.

DOPSD0104 – This is actual information sourced from the field that directly interfaces with SCADA data.

DOPSD0105 – This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 10% POE value/Actual) * Zone substation summation (DOPSD0104). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at coincident demand.

DOPSD0106 – This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 50% POE value/Actual) * Zone substation summation (DOPSD0104). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at coincident demand.

5.3.2. Annual system maximum demand characteristics at the transmission connection point – MW measure

DOPSD0107- This is actual data sourced from the Interval Metering System (used for market settlements) and interval metering data. It is recalculated by summing the entire boundary metering data in the IMS Spread sheet.

DOPSD0108 - This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 10% POE value/Actual) * Transmission Connection Point summation (DOPSD0107).

The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at non-coincident demand.

DOPSD0109 - This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 50% POE value/Actual) * Transmission Connection Point summation (DOPSD0107). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at non-coincident demand.

DOPSD0110- This is actual information sourced from IMS. It's a maximum of the summated transmission connection point demands.

DOPSD0111- This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 10% POE value/Actual) * Transmission Connection Point summation (DOPSD0110). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at coincident demand.

DOPSD0112- This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 50% POE value/Actual) * Transmission Connection Point summation (DOPSD0110). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at coincident demand.

5.3.3. Annual system maximum demand characteristics at the zone substation level – MVA measure

DOPSD0201 - This is actual information sourced from the field that directly interfaces with SCADA data.

DOPSD0202 - This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 10% POE value/Actual) * Zone substation summation (DOPSD0201). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at coincident demand.

DOPSD0203 - This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 50% POE value/Actual) * Zone substation summation (DOPSD0201). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at coincident demand.

DOPSD0204 - This is actual information sourced from the field that directly interfaces with SCADA data.

DOPSD0205 - This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 10% POE value/Actual) * Zone substation summation (DOPSD0204). The assumption underpinning this estimation is that the power factor at UE non-coincident demand is held at coincident demand.

DOPSD0206 - This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 50% POE value/Actual) * Zone substation summation (DOPSD0204). The assumption underpinning this estimation is that the power factor at UE non-coincident demand is held at coincident demand.

5.3.4. Annual system maximum demand characteristics at the transmission connection point – MVA measure

DOPSD0207 - This is actual information sourced from IMS. It's a summation of maximum demands of the individual transmission connection points sourced from IMS.

DOPSD0208 - This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 10% POE value/Actual) * Transmission Connection Point summation (DOPSD0207). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at non-coincident demand.

DOPSD0209 - This is an estimate (per the variable definition) with data sourced from IMS and NIEIR and is calculated as the (ratio of 50% POE value/Actual) * Transmission Connection Point summation (DOPSD0207). The assumption underpinning this estimation is that sensitivity at UE maximum demand is held at non-coincident demand.

DOPSD0210 - This is actual information sourced from IMS. It's a maximum of the summated transmission connection point demands.

DOPSD0211 - This is an estimate (per the variable definition) with data sourced from IMS and NIEIR. The 10% POE coincident weather adjusted system annual maximum Demand in MW (DOPSD0111) is divided by the same system average power factor calculated at non-coincident maximum demand (DOPSD0207) to calculate the information required under DOPSD0211. The assumption underpinning this estimation is that the power factor at UE non-coincident demand is held at coincident demand.

DOPSD0212 – The 50% POE coincident weather adjusted system annual maximum Demand in MW (DOPSD0112) is divided by the same system average power factor calculated at non-coincident maximum demand (DOPSD0207) to calculate the information required under DOPSD0212. The assumption underpinning this estimation is that the power factor at UE non-coincident demand is held at coincident demand.

5.3.5. Power factor conversion between MVA and MW

DOPSD0301 – This is calculated as DOPD0110/DOPSD0210.

DOPSD0302 – This is an estimate as lack of available data based on measurements of feeder power factor on those feeders without power factor correction. It is a fixed value of 0.89 which is the Network Log Management specification.

DOPSD0303 – This data is sourced from SCADA. This is the feeder summation power factor from all 11kV zone substations obtained at summer peak demand.

DOPSD0304 - This is an estimate as lack of available data based on measurements of feeder power factor on those feeders without power factor correction. It is a fixed value of 0.89 which is the Network Log Management specification.

DOPSD0305 - This data is sourced from SCADA. This is the feeder summation power factor from all 22kV zone substations obtained at summer peak demand.

DOPSD0306 – UE does not have 33kV lines. Set as zero.

DOPSD0307 - This is a formula based on the non-coincident power flow into the zone substation excluding zone substation transformation which is DOPSD0101 divided by DOPSD0201.

DOPSD0308 – UE does not have 132kV lines. Set as zero.

DOPSD0309 - This data is sourced from SCADA. This is the feeder summation power factor from the one (SH) 6.6kV zone substations obtained at summer peak demand.

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

UE retrieves this information from the CIS+ billing system (2006-2009) and CIS+/SAP (2010-2013). This information therefore is actual billing information and does not require estimations and scaling to previously reported values. The data is extracted from the Q-report. Please refer to Chapter 2 for more information on the Q-report.

DOPSD0401 – Summated Chargeable Contracted Maximum Demand is not captured by UE

DOPSD0402 – This is actual data sourced straight from the CIS+ billing system (2006-2009) and CIS+/SAP (2010-2013) with no calculations performed. Please see above.

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

The values are converted from MW to MVA.

DOPSD0403 – Summated Chargeable Contracted Maximum Demand is not captured by UE

DOPSD0404 – This is actual data sourced straight from the CIS+ billing system (2006-2009) and CIS+/SAP (2010-2013) with no calculations performed. Please see above.

6. Physical Assets

6.1. Network Capacities Variables

6.1.1. Overhead network circuit length at each voltage

The data has been sourced from UE Geographical information System from the AM/FM reports. The reports are saved in Microsoft excel, and a simple pivot table is created in using the headers from the report, and from this, the following data for the variables has been extracted below. The data extracted is then categorised to suit the Economic Benchmarking RIN spread sheet. UE does not own 33klv and 132kv lines. Unless otherwise stated, the data for the years 2007-2013 is actual, and 2006 is an estimate, with the key assumption in the estimate being that the data used (2005 and 2007 data) is reasonable enough to provide an approximation for 2006.

DPA0101 – This is a calculation sourced from the AM/FM reports portal within the UE Geographical system. The data from 2007 – 13 is actual data, with 2006 being an estimate. The calculation used is the *total sum of LV lines*. The key assumption for the 2006 estimate is that the data across 2005 and 2007 is a reasonable basis to average 2006 figures.

DPA0102 - This is a calculation sourced from the AM/FM reports portal within the UE Geographical system. The data from 2007 – 13 is actual data, with 2006 being an estimate. The calculation used is the *sum of HV lines (km) for 11kV rows*. The key assumption for the 2006 estimate is that the data across 2005 and 2007 is a reasonable basis to average 2006 figures.

DPA0103 – This data is sourced from the AM/FM reports portal within the UE Geographical system. The data from 2013 is actual data, with 2006-2012 being an estimate. The data is straight from the GIS for November 2013 (no calculation). The key assumption for the estimate in years 2006-2012 is that the SWER length has remained unchanged from 2013.

DPA0104 - This is a calculation sourced from the AM/FM reports portal within the UE Geographical system. The data from 2007 – 13 is actual data, with 2006 being an estimate. The calculation used is the *sum of HV lines (km) for 22kV rows (including SubT and SubT OOS*). The key assumption for the 2006 estimate is that the data across 2005 and 2007 is a reasonable basis to average 2006 figures.

DPA0105 – UE does not, or has ever owned any 33kV overhead lines within the period under question. Therefore values 2006 – 2013 are actual and set to zero.

DPA0106 - This is a calculation sourced from the AM/FM reports portal within the UE Geographical system. The data from 2007 – 13 is actual data, with 2006 being an estimate. The calculation used is the *sum of HV lines (km) for 66kV rows (including 66kV OOS*). The key assumption for the 2006 estimate is that the data across 2005 and 2007 is a reasonable basis to average 2006 figures.

DPA0107 - UE does not own, or has ever owned any 132kV overhead lines within the period under question. Therefore values 2006 – 2013 are actual and set to zero.

DPA0108 - This is a calculation sourced from the AM/FM reports portal within the UE Geographical system. The data from 2007 – 13 is actual data, with 2006 being an estimate. The calculation used is the *sum of HV lines (km) for 6.6kV rows*. The key assumption for the 2006 estimate is that the data across 2005 and 2007 is a reasonable basis to average 2006 figures.

6.1.2. Underground network circuit length at each voltage

The data has been sourced from UE Geographical information System from the AM/FM reports. The reports are saved in Microsoft excel, and a simple pivot table is created using the headers from the report, and from this, the data extracted is then categorised to suit the Economic Benchmarking RIN spread sheet. UE does not own 33klv and 132kv cables. Unless otherwise stated, the data for the years 2007-2013 is actual, and 2006 is an estimate, with the key assumption in the estimate being that the data used (2005 and 2007 data) is reasonable enough to provide an approximation for 2006**.**

DPA0201 - This is a calculation sourced from the AM/FM reports portal within the UE Geographical system. The data from 2007 – 13 is actual data, with 2006 being an estimate. The calculation used is the *total sum for LV cables (km)*. The key assumption for the 2006 estimate is that the data across 2005 and 2007 is a reasonable basis to average 2006 figures.

DPA0202 - This is a calculation sourced from the AM/FM reports portal within the UE Geographical system. The data from 2007 – 13 is actual data, with 2006 being an estimate. The calculation used is the *sum of HV cables (km) for 11kV row*. The key assumption for the 2006 estimate is that the data across 2005 and 2007 is a reasonable basis to average 2006 figures.

DPA0203 - This is a calculation sourced from the AM/FM reports portal within the UE Geographical system. The data from 2007 – 13 is actual data, with 2006 being an estimate. The calculation used is the *sum of HV cables (km) for 22kV row (including SubT and SubT OOS)*. The key assumption for the 2006 estimate is that the data across 2005 and 2007 is a reasonable basis to average 2006 figures.

DPA0204 - UE does not own, or has ever owned any 33kV overhead lines within the period under question. Therefore values 2006 – 2013 are actual and set to zero.

DPA0205 - This is a calculation sourced from the AM/FM reports portal within the UE Geographical system. The data from 2007 – 13 is actual data, with 2006 being an estimate. The calculation used is the *total sum of LV lines*. The key assumption for the 2006 estimate is that the data across 2005 and 2007 is a reasonable basis to average 2006 figures.

DPA0206 - UE does not own, or has ever owned any 132kV overhead lines within the period under question. Therefore values 2006 – 2013 are actual and set to zero.

DPA0207 - This is a calculation sourced from the AM/FM reports portal within the UE Geographical system. The data from 2007 – 13 is actual data, with 2006 being an estimate. The calculation used is the *sum of HV cables (km) for 6.6kV row*. The key assumption for the 2006 estimate is that the data across 2005 and 2007 is a reasonable basis to average 2006 figures.

6.1.3. Estimated overhead network weighted average MVA capacity by voltage class

The data has been sourced from UE Demand Management System. The data extracted is then categorised to suit the Economic Benchmarking RIN spread sheet. Per the table heading, these figures are, by nature, estimates.

DPA0301 – This is a calculation (*Average Distribution Substation Nameplate Rating (excluding pole top capacitor bank type substations) / Average Number of Distribution Circuits*) with the distribution circuit number taken from the TLM report within the UE Demand Management System.

DPA0302 - This is a calculation (Average rating of the 11kV feeders x Summer Cyclic Rating* sqrt(3)/1000*.98) with the average rating and summer cyclic ratings taken from the Load Forecast report within the UE SAP.

DPA0303 – This is the fixed value of the isolation transformer at 100kVa.

DPA0304 - This is a calculation (Average rating of the 22kV feeders x Summer Cyclic Rating* sqrt(3)/1000*.98) with the average rating and summer cyclic ratings taken from the Load Forecast report within SAP.

DPA0305 – UE does not own 33kV lines nor has ever owned them in the period under question. Therefore the number has been set to zero.

DPA0306 - This is a calculation (*'SubTlines data' from NCC ratings Database multiplied *66*sqrt(3)/1000 for the relevant year*) based on inputs taken from the NCC Ratings Database within SAP

DPA0307 – UE does not own 132kV lines nor has ever owned them in the period under question. Therefore the number has been set to zero.

DPA0308 - This is a calculation based on inputs taken from the Load Forecast report within SAP.

6.1.4. Estimated underground network weighted average MVA capacity by voltage class

The data has been sourced from UE Demand Management System. The data extracted is then categorised to suit the Economic Benchmarking RIN spread sheet. Per the table heading, these figures are, by nature, estimates.

DPA0401 – This item is equal to DPA0301.

DPA0402 - This is a calculation (*Average Rating of 11kV feeders * Summer Cyclic Rating* sqrt(3)/1000 *1.02*) based on feeder and summer cyclic ratings taken from the Load Forecast report within SAP

DPA0403 - This is a calculation (A*verage Rating of 22kV feeders * Summer Cyclic Rating* sqrt(3)/1000 *1.02*) based on feeder and summer cyclic ratings taken from the Load Forecast report within SAP

DPA0404 – UE does not own 33kV cables. Therefore the number has been set to zero.

DPA0405 - This is a calculation (A*verage Rating of 66kV feeders * Summer Cyclic Rating* sqrt(3)/1000 *1.02*) based on feeder and summer cyclic ratings taken from the Load Forecast report within SAP

DPA0406 – UE does not own 132kV cables. Therefore the number has been set to zero.

DPA0407 - This is a calculation (A*verage Rating of 6.6kV feeders * Summer Cyclic Rating* sqrt(3)/1000 *1.02*) based on feeder and summer cyclic ratings taken from the Load Forecast report within SAP

6.2. Transformer Capacities Variables

6.2.1. Distribution transformer total installed capacity

The data has been sourced from UE Demand Management System. The data extracted is then categorised to suit the Economic Benchmarking RIN spread sheet. UE does not own cold spare capacity and information relating to customer owned HV transformers.

DPA0501 – This is actual data sourced from the TLM report within SAP. The calculation is the *sum of all distribution transformer name plates* column within the TLM report.

DPA0502 – This is actual data that has been sourced from IMS data and is calculated as the *sum of customer maximum demand*.

DPA0503 – This is estimated data, with the source inputs coming from SAP and the minimum inventory level data. The key assumption is that the minimum inventory level will be maintained and is calculated as (*the actual transformers replaced in 2013 calendar year/total transformers)*minimum inventory level*.

6.2.2. Zone Substation transformer Capacity

The data has been sourced from UE Demand Management System. The data extracted is then categorised to suit the Economic Benchmarking RIN spread sheet.

This is the total nameplate rating (OFDAF) of all zone substation transformers on the UE network in the Ratings Database.

In years where archived versions of the Ratings database were not available, the total cyclic rating for the year is used from the Load Forecast Spread-sheet but multiplied by the ratio of the present total name plate rating divided by the present total cyclic rating to get an equivalent nameplate rating.

DPA0601 – UE has no transformers that fit this description

DPA0602 – UE has no transformers that fit this description

DPA0603 – From 2011 onwards this item contains actual data sourced from the network equipment capacity ratings database. For 2006 – 2010 this data is estimated as described above.

DPA0604 – UE does not have any stepped transformation; therefore this is the same as DPA0603.

DPA0605 – UE does not have any cold spare for distribution, therefore has been set as zero.

6.3. Public Lighting

The data has been sourced from UE Geographical information System. The data extracted is then categorised to suit the Economic Benchmarking RIN spread sheet.

DPA0701 – This data has been sourced from a spread sheet of the AM/FM “Public lights” report which is taken from the UE GIS. The data is actual from 2007-2013, and estimated in 2006. The key assumption for the estimated data is that the values used (2005 and 2007 data) provides a reasonable basis for the approximation of 2006 data. The calculation is the total for the *“sum of public lights”* column.

DPA0702 – This is actual data that has been sourced straight from the AM/FM “Public Lights” report taken from the UE GIS.

7. Quality of Services

7.1. Reliability

7.1.1. Inclusive of MEDs

The data has been sourced from Demand Management System. The system has been configured to capture the data required to report this information as per the STPIS requirements. The data from the system is used to populate cells with values. For further explanation, please refer to attached procedure document UE PR 2301 Section 6.2.1

For historical data 2006-2012, UE has sourced the information to complete these tables from the reports submitted to the AER over those years.

DQS0101 – This is actual data that has been sourced from the DMS system, more specifically the Service provider annual reporting - STPIS Reliability report. It is calculated as the sum of *Network SAIDI All Events* Column within the report.

DQS0102 – This is actual data that has been sourced from the DMS system, more specifically the Service provider annual reporting - STPIS Reliability report. It is calculated as the sum of *Network SAIDI after removing excluded events* Column within the report.

DQS0103 – This is actual data that has been sourced from the DMS system, more specifically the Service provider annual reporting - STPIS Reliability report. It is calculated as the sum of *Network SAIFI All Events* Column within the report.

DQS0104 – This is actual data that has been sourced from the DMS system, more specifically the Service provider annual reporting - STPIS Reliability report. It is calculated as the sum of *Network SAIFI after removing excluded events All Events* Column within the report.

7.1.2. Exclusive of MEDs

The data has been sourced from Demand Management System. The data extracted is then categorised to suit the Economic Benchmarking RIN spread sheet.

For historical data 2006-2010, UE has sourced the information to complete these tables from the reports submitted to the AER over those years. For 2011 onwards the information has been obtained from the Annual RINs.

Additionally, Major Event Days (MEDs) were not required in the annual regulatory reports prior to calendar year 2011 and no threshold existed. Hence for the years 2006-2010, as per the Economic Benchmarking RIN definitions, 2012 Threshold has been applied.

DQS0105 - This is actual data that has been sourced from the DMS system, more specifically the Service provider annual reporting - STPIS Reliability report. It is calculated as the sum of *Network SAIDI All Events (excluding MED)* Column within the report.

DQS0106 - This is actual data that has been sourced from the DMS system, more specifically thee Service provider annual reporting - STPIS Reliability report. It is calculated as the sum of *Network SAIDI after removing excluded events and MED* Column within the report.

DQS0107 - This is actual data that has been sourced from the DMS system, more specifically thee Service provider annual reporting - STPIS Reliability report. It is calculated as the sum of *Network SAIFI All Events (excluding MED)* Column within the report.

DQS0108 - This is actual data that has been sourced from the DMS system, more specifically the Service provider annual reporting - STPIS Reliability report. It is calculated as the sum of *Network SAIFI after removing excluded events and MED* Column within the report.

7.2. Energy not supplied

Energy not supplied was calculated based on annual feeder reliability data.

Energy not supplied =Average customer demand **×** number of customers interrupted **×** duration of interruption

Average customer demand was calculated based on the average annual feeder demand. These demand figures are obtained from the DMS.

The figures for the number of customers interrupted and the duration of the interruption in minutes from the ESC and RIN submissions.

Table 7.2 is populated with source data that originates from the DMS system and is categorised to suit the Economic Benchmarking RIN spreadsheet. There were two separate methods to obtain the data for Tables 7.2 due to the different regulatory reporting requirements for calendar years 2006–2010 and 2011–2012.

For 2006-2010 the data is sourced from the ESC submissions. The actual information was collated from the annual reports submitted to the regulator.

For 2011 & 2012 the data was to have been obtained from the 2011 & 2012 Annual RINs. However the source data used for those calculations have been found to be incomplete. As a result UE has to use updated information to re-calculate the average feeder demand. The re-calculated average demand per feeder is then multiplied by the number of minutes off supply in the respective RIN's (2011 & 2012). This then allowed the derivation of the planned and unplanned energy not supplied.

Energy Not Supplied (planned)

The duration of planned interruption was obtained from the 'Total planned minutes off-supply' column of the '6b. Annual Feeder Reliability' tab.

DQS0201 - The energy not supplied (planned) was calculated based on the multiplication of this column with the corresponding values in the 'Number of distribution customers' column and the corresponding average annual feeder demand.

As UE does not have the historical data on customer demand, the data for energy not supplied was based on the annual reports submitted to the regulator. The energy not supplied (planned) data was obtained from the 'Feeder Reliability (6mth&Annual)' tab of the spreadsheet. The total planned energy not supplied was the summation of the 'Energy not supplied per feeder - planned' column in the tab.

Energy Not Supplied (unplanned) -

The duration of unplanned interruption was obtained from the 'Unplanned minutes off-supply column of the '6b. Annual Feeder Reliability' tab.

DQS0202 - The energy not supplied (unplanned) was calculated based on the multiplication of this column with the corresponding values in the 'Number of distribution customers' column and the corresponding average annual feeder demand.

As UE does not have the historical data on customer demand, the data for energy not supplied was based on the annual reports submitted to the regulator. The energy not supplied (unplanned) data was obtained from the 'Feeder Reliability (6mth&Annual)' tab of the spreadsheet. The total unplanned energy not supplied was the summation of the 'Energy not supplied - unplanned' column in the tab.

7.3. System Losses

Energy losses incurred in the transfer of electricity over distribution network, calculated as [total energy supplied minus total energy delivered] / [total energy supplied]. Losses are inclusive of theft.

For historical data 2006-2012, UE has sourced the information to complete these tables from the Distribution Loss Factors reports submitted to the AER over those years.

DQS03 – This is actual data sourced from IMS/ Billing Data – DLF Submission into AER. The calculation is the DLF calculation methodology

7.4. Capacity Utilisation

DQS04 – This is the percentage of non–coincident summated raw system annual maximum demand in MVA (DOPSD0201) divided by the summation of total installed zone substation transformer capacity (DPA0604) at all the zone substations.

8. Operating Environment

8.1. Density Factors

DOEF0101 - Customer density does not need any additional information and can be calculated using information available in other categories. The customer density is calculated by DOPCN01/DOEF0301

DOEF0102 - Energy density does not need any additional information and can be calculated using information available in other categories. The customer density is calculated by DOPED01/DOPCN01.

DOEF0103 - Demand density does not need any additional information and can be calculated using information available in other categories. The customer density is calculated by (DOPSD0201*1000)/DOPCN01*1000.

8.2. Terrain Factors

DOEF0201 - Rural Proportion 2013. This information has been derived from the UE GIS database on the 27 March 2014 so is treated as “Actual”. This is then divided by the total route length.

In previous years (2009-12) actual information was not available, so has been estimated using the change in route length percentage.

DOEF0202 - 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 (orange cells) as it would be unnecessarily burdensome to do so. Providing information for the most recent regulatory year only is consistent with the instructions for Table 8.2 provided by AER for the Economic Benchmark RIN.

DOEF0203 - 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 (orange cells) as it would be unnecessarily burdensome to do so.

Providing information for the most recent regulatory year only is consistent with the instructions for Table 8.2 provided by AER for the Economic Benchmark RIN***.***

DOEF0204 - Total Vegetation Maintenance Spans 2013

This information has been derived for the year “2013” from 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 (orange cells) as it would be unnecessarily burdensome to do so.

Providing information for the most recent regulatory year only is consistent with the instructions for Table 8.2 provided by AER for the Economic Benchmark RIN.

DOEF0205 - Total Number of Spans has been derived for the year “2013” from a report run out of the UE GIS database on the 27th March 2014 so is treated as “Actual”.

In previous years (2009-12) actual information was not available, so has been estimated using he percentage change in route length as a basis for these years.

DOEF0206 - The average urban span cycle is estimated. This data is currently sourced from the VEMCO VMS system of Spans inspected annually (2013). This is behind the strategic objective documented in the Electric Line Clearance Management Plan (ELCMP) of a 2 year cycle which equates to (DOEF0202/2 year) = total spans per annum.

The VEMCO VMS for 2013 indicates only 80,811 spans inspected. The percentage difference between the planned total spans per annum inspected and the 80,811 actual spans inspected is then converted into years to work out how far ahead/behind the program is, i.e. completing the program 5% behind, would mean it is taking 2.05 years to complete.

For the period 2009-12 UE can only estimate the achieved cycles. The previous UE ELCMP states the following clearance cycles for LBRA or Urban Areas. However the current results extrapolated back from the 2013 data would indicate a slightly longer program was estimated to have been achieved.

DOEF0207 - The average rural span cycle is currently estimated at 2 years. This data is currently sourced from the VEMCO VMS system of Spans inspected annually (2013). This is currently on target with the strategic objective documented in out Electric Line Clearance Management Plan of a 2 year cycle. Spans within the HBRA are also subject to an annual pre-summer inspection.

This data is currently sourced from the VEMCO VMS system of Spans inspected annually (2013). This is behind the strategic objective documented in out Electric Line Clearance Management Plan of a 2 year cycle which equates to (DOEF0203/2) = total spans per annum.

The VEMCO VMS for 2013 indicates only 9,017 spans inspected. The percentage difference between the planned total spans per annum inspected and the 9,017 actual spans inspected is then converted into years to work out how far ahead/behind the program is., i.e. a difference of 10% ahead would indicate that the program was completed in 1.9 years.

For the period 2009-12 UE can only estimate the archived cycles. The previous UE ELCMP states the following clearance cycles for HBRA or Rural Areas. However the current results extrapolated back from the 2013 data would indicate a slightly shorter program was estimated to have been achieved.

DOEF0208 - 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 completed in DOEF0206) / DOEF0202).

DOEF0209 - 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 (total number of trees * 24% * (% Maintenance Span Cycle completed in DOEF0207) / DOEF0203).

DOEF0210 - UE does not keep any records of the number of actual defects cleared compared with the number of trees cleared in the completion of its annual cycle. As the 2 year cycle is only recent UE can only give a best estimate of such numbers.

In the urban and CBD areas UE estimates that in 2013 25% of trees cleared were within the regulatory clearance requirements and as such did not meet the standard required by UE.

Therefore the calculation is 25%* DOEF0208

UE has not provided data for previous years (orange cells) as it would be unnecessarily burdensome to do so.

Providing information for the most recent regulatory year only is consistent with the instructions for Table 8.2 provided by AER for the Economic Benchmark RIN.

DOEF0211 - UE does not keep any records of the number of actual defects cleared compared with the number of trees cleared in the completion of its annual cycle. As the 2 year cycle is only recent UE can only give a best estimate of such numbers.

Unlike the urban areas, UE undertakes an annual pre-summer inspection in the rural (HBRA) areas. UE estimates that in 2013 20% of trees cleared in their cyclic program were within the regulatory clearance requirements and as such did not meet the standard required by UE.

Therefore the calculation is 20%* DOEF0209

UE has not provided data for previous years (orange cells) as it would be unnecessarily burdensome to do so.

Providing information for the most recent regulatory year only is consistent with the instructions for Table 8.2 provided by AER for the Economic Benchmark RIN.

DOEF0212 - UE does not have and never has had any tropical portion of land within is distribution area.

DOEF0213 - UE does not keep any records of the km of standard (2X2 vehicular access of its network. UE can only give a best estimate of such number which is that only 0.01% of the total km's that would require a 4 X 4 vehicle or a climbing work party. Therefore the calculation is 0.01%* DOEF0301

DOEF0214 - This information has been derived from a report run out of the UE GIS database on the 27th March 2014 so is treated as "Actual" for 2013. For the years 2009 – 2012 the data is an estimated.

8.3. Service Area Factors

DOEF0301 - This information has been derived from a report run out of the UE GIS database and so is treated as "Actual" for 2013. For the years 2006 – 2012 the data is an estimate. It is has been estimated based on the percentage movement of overhead circuit line length from one year to the next. This estimate is used because route line length is the distance of overhead lines between two poles. Hence route line length is a sub-set of circuit line length and is therefore the best estimate to use.

8.4. Weather Stations

DOEF04001 – Presently three weather stations owned by the Bureau of Meteorology are located in UE service area. This can be verified by going to the BOM Weather Station website: http://www.bom.gov.au/climate/cdo/about/sitedata.shtml and entering the station ID of the three weather stations at the prompt.