Basis of Preparation – Economic Benchmarking Data

31 December 2013

1. Overview

This Basis of Preparation document supports the preparation and reporting of the data presented in SPI Electricity Pty Limited's ("SPI Electricity") reports entitled 'DNSP economic benchmarking data - Actual Information', 'DNSP economic benchmarking data - Estimated Information', 'DNSP economic benchmarking data - Consolidated Information' and 'Other Supporting Information' ("the Reports"). The Reports provide data solely for the use of the Australian Energy Regulator ("AER") to perform benchmarking activities under the AER's Better Regulation program.

The ultimate Australian parent of SPI Electricity is SP Australia Networks (Distribution) Ltd which is part of a listed stapled group trading as SP AusNet. SP AusNet comprises the Stapled Group of SP Australia Networks (Distribution) Ltd and its subsidiaries, SP Australia Networks (Transmission) Ltd and its subsidiaries, and SP Australia Networks (Finance) Trust. The Stapled Group is also referred to as the SP AusNet Group.

The Reports have been prepared in accordance with the 'Regulatory Information Notice issued under section Division 4 of Part 3 of the National Electricity (Victoria) Law' ("RIN") issued by the AER on 28 November 2013, the accompanying 'Economic Benchmarking RIN for distribution network service providers - Instructions and Definitions' issued by the AER and other authoritative pronouncements of the AER. SPI Electricity's regulatory year is the period 1 January to 31 December ("Regulatory Year"). Data included in the Reports has been provided for each Regulatory Year from 2006 through to 2013. All financial data included in the Reports is presented in thousands of Australian dollars, rounded to the nearest dollar. Non-financial data is stated as per the measures specified in the Reports and includes a minimum of four figures (except where the RIN requires numbers of units).

Materiality has been applied throughout the Reports and Basis of Preparation. Materiality is defined as information that if omitted, misstated or not disclosed has the potential, individually or collectively to influence the economic decisions of users.

The Reports require inputs to be allocated between Standard Control Services and Alternative Control Services.

For the Regulatory Years upon which the AER has made a distribution determination, Standard Control Services are defined as per the National Electricity Rules ("NER"). For clarity, Standard Control Services capture services only available through the network (typically provided to all customers or a broad class of customers) recovered through general network tariffs. For the Regulatory Years where an AER determination was not in effect, Standard Control Services are considered prescribed services and prescribed metering services as determined by the Essential Services Commission of Victoria.

Alternative Control Services are defined in the NER. By way of context, Alternative Control Services are intended to capture distribution services provided at the request of, or for the benefit of, specific customers with regulatory oversight of prices. Where an AER determination was not in effect at the time, Alternative Control Services are excluded distribution services as determined by the Essential Services Commission of Victoria.

In conformity with AER requirements, the preparation of the Reports requires the use of certain critical management estimates. Where estimated information has been presented, the circumstances and the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is SPI Electricity's best estimate has also been set out below. By definition, estimates seldom equal the related actual results and estimates have only been made for the purpose of disclosing the information requested. Considerations of the cost and efficiency of preparation as well as accuracy have been taken into account in determining the best methodology to apply.

For the purpose of preparing the Reports, 'estimated information' is defined as information presented in the Reports whose presentation is not materially dependent on information recorded in accounting records or other records used in the normal course of business, and whose presentation for the purpose of the RIN is contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the Reports.

'Actual Information' is defined as information materially dependent on information recorded in historical accounting records or other records used in the normal course of business, and whose presentation is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation.

The preparation methodologies and information sources adopted in the preparation of the Reports are set out below. These methodologies and sources have been consistently applied and used for all Regulatory Years, unless otherwise stated.

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2. Revenue

Distribution Use of Systems Revenue ("Revenue") is measured at the fair value of the consideration received or receivable, net of the amount of Goods and Services Tax ("GST") payable to the taxation authority. Revenue is recognised as the services are rendered and is reported inclusive of incentive scheme penalties and rewards. Total Revenue is disaggregated by chargeable quantity and also by customer class.

The accounting policies adopted by SPI Electricity in relation to Revenue have not materially changed during any of the Regulatory Years covered by the Reports.

Table 2.1 Revenue grouping by Chargeable Quantity

Revenue reported has been classified into the chargeable quantity which most closely reflects the basis upon which the revenue was charged to customers. Where it has been determined that Revenue cannot be allocated to the specified chargeable quantity classifications in DREV0101 to DREV0112, Revenue has been reported against 'Revenue from other Sources' (DREV0113).

<u>Preparation Methodology</u>:

Standard Control:

For Regulatory Years 2011 to 2013, Revenue by distribution tariff was sourced from the Annual Regulatory Accounts and allocated into the categories presented using Distribution Use of System ("DUOS") tariff schedules. For Regulatory Years 2006 to 2010, Revenue schedules were prepared using tariff quantities sourced from the Annual Regulatory Accounts and tariff rates obtained from historic approved tariff submissions. This Revenue data was allocated into the categories presented using DUOS tariff schedules as the DUOS tariff schedules were not presented in the Annual Regulatory Accounts in the 2006 to 2010 Regulatory Years.

Amounts included as 'Revenue from other Sources' relate to summer export payments made to customers for solar feed-in which forms part of DUOS Revenue reported in the Annual Regulatory Accounts.

Alternative Control:

For all Regulatory Years, Revenue was sourced from the Annual Regulatory Accounts and allocated into the categories presented.

Table 2.2 Revenue grouping by Customer Type or Class

Revenue reported has been classified into the Customer Type or Class which most closely reflects the customers from which revenue was charged. Where it has been determined that Revenues cannot be allocated to the specified Customer Type in DREV0201 to DREV0205, Revenue has been reported against 'Revenue from other Customers' (DREV0206).

Preparation Methodology:

Standard Control:

Revenue reported in Standard Control Table 2.1 was allocated into customer type or class based on DUOS tariff schedules.

Alternative Control:

Revenue reported in Alternative Control Table 2.1 was allocated in total to Revenue from Other Customers as the Revenue cannot be allocated to the specified chargeable quantity classifications in DREV0101 to DREV0112 based on the information available.

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

The penalties or rewards from the service target performance incentive scheme (“STPIS”) or efficiency benefit sharing scheme (“EBSS”) have been reported based on the year that the penalty or reward was applied, not the year in which it was earned. The penalties or rewards from the schemes applied by previous jurisdictional regulators that are equivalent to the STPIS or EBSS schemes have been reported against the applicable scheme category.

Preparation Methodology:

Information was sourced from Annual Regulatory Accounts, Annual Tariff Submissions & Post Tax Revenue Model (and the Essential Services Commission (“ESC”) equivalent for the Regulatory Years from 2006 to 2010).

EBSS:

For Regulatory Years 2011 to 2013, EBSS revenue or penalties were calculated by smoothing the calculated nominal EBSS allowance over the 5 year period from 2011 to 2015 based on the Smoothed Revenue profile in the 2011 to 2015 Post Tax Revenue Model. For Regulatory Years 2006 to 2010, EBSS was calculated by smoothing the total prescribed EBSS allowance per the ESC Revenue Determination over the 5 year period from 2006 to 2010 based on the Smoothed Revenue profile in the 2006 to 2010 Post Tax Revenue Model.

STPIS:

For Regulatory Years 2006 to 2010 and 2013, STPIS was calculated by dividing the total reported DUOS revenue by (1+ incentive scheme rate) and reporting the resultant difference between reported Revenue and this adjusted Revenue as STPIS.

Other:

For Regulatory Years 2011 to 2013, a proportion of annual revenue has been attributed to the nominal S–Factor true up included in the 2011-15 revenue requirement reflecting the close out of the previous ESC S-Factor regime. To calculate the impact in each of the years, the total S-Factor true up over the five years was allocated to individual years based on the Smoothed Revenue profile in the 2011 to 2015

Post Tax Revenue Model. This approach most accurately reflects the years in which the revenue was generated. The calculated incentive revenue has been disclosed as 'Other' (DREV0303) in Table 2.3.

Estimated Information:

The STPIS, EBSS and Other data provided is considered 'estimated' information due to assumptions made in the preparation and calculation of the data. In relation to EBSS, it has been assumed that EBSS Revenue (and Revenue derived under the historically equivalent scheme) was collected in accordance with the allowances or penalties prescribed for the applicable 5 year Revenue determination period.

In relation to STPIS, it has been assumed that STPIS Revenue was collected in accordance with the incentive scheme rate prescribed by the AER for the applicable period.

In relation to the 'Other' categorisation, Management has assumed that applying a single S-Factor percentage to all DUOS revenue derives a reasonable estimate of incentive revenue.

The above mentioned estimates and assumptions are considered to provide Management's best estimate of the information required based on the data available as the measures are not separately captured.

3. Operating Expenses

Operating Expenses ("Opex") are the costs of operating and maintaining the network (excluding all capital costs and capital construction costs). The categorisation of Opex is presented in accordance with the Cost Allocation Methodology ("CAM") and is materially consistent across the Regulatory Years based originally on the Essential Service Commission of Victoria Guideline No.3 under which Regulatory Accounts were prepared prior to 2011.

The SP AusNet Group owns and operates 3 regulated networks – an electricity distribution network, a gas distribution network, and an electricity transmission network. Opex that is incurred for a particular network is allocated directly to that network. Overhead costs that cannot be directly allocated to a particular network are proportioned amongst SP AusNet's 3 regulated and unregulated networks via a quarterly Activity Based Costing survey process completed by all cost centre managers and in accordance with SP AusNet's CAM.

The accounting policies adopted by SPI Electricity in relation to Opex have not materially changed during any of the Regulatory Years covered by the Reports.

Table 3.1 Opex categories: Table 3.1.1 Current opex categories and cost allocations

Opex categories and allocations have been presented as per the categories in the most recent Annual Regulatory Accounts and in accordance with requirements of the CAM, the Annual Regulatory Accounts and the Annual Reporting Requirements that were in effect from the 2011 to 2013 Regulatory Years.

Preparation Methodology:

Using data extracted from the Annual Regulatory Accounts and information from the financial system, operating expenses were allocated into the categories applicable from the 2011 Regulatory Year. For categories which are the same between the Annual Regulatory Accounts and the categories from the 2011 Regulatory Year, the costs disclosed remained the same. For the categories between the 2006 to 2010 Regulatory Years which are different to the categories from the 2011 Regulatory Year, prior year Annual Regulatory Accounts working files were used to obtain the required information.

In terms of classifying historic maintenance costs into the current categories, a suitable expert reviewed the ledger cost codes to determine how they should be mapped to the current categories. This mapping was not performed for the 2009 and 2010 Regulatory Years as the required data was not readily available. Therefore, the average percentage allocation of maintenance costs into the current Routine, Condition Based and Emergency maintenance categories was calculated across the 2011 to 2013 Regulatory Years. These percentages were applied to the total maintenance costs in the 2009 and 2010 Regulatory Years to derive an estimate of the required information.

The line items and figures are sourced from the Maintenance Expense and Operating Expense templates of the respective Regulatory Year's Annual Regulatory Accounts. The Standard Control Services figures shown include Advanced Metering Infrastructure ("AMI").

Estimated Information:

The sub-categorisation of Maintenance costs variables DOPEX0101-DOPEX0103 for the 2009 and 2010 Regulatory Years was estimated as discussed above as the required data was not readily available. It is assumed that the nature of maintenance expenses for Regulatory Years 2009 and 2010 was materially consistent with those of the 2011 to 2013 Regulatory Years, hence it is reasonable to apply the average percentage allocation of total maintenance cost into the current maintenance categories of the 2011 to 2013 Regulatory Years upon the 2009 and 2010 Regulatory Years.

Table 3.1 Opex categories: Table 3.1.2 Historical opex categories and cost allocations

Opex categories and allocations have been presented as per the categories in the Annual Regulatory Accounts and in accordance with requirements of the CAM, the Annual Regulatory Accounts and the Annual Reporting Requirements that were in effect for the individual Regulatory Year. Opex for Standard Control Services and Alternative Control Services reconciles to historical Opex as disclosed in the Annual Regulatory Accounts.

Preparation Methodology:

Data has been extracted from the Annual Regulatory Accounts for each relevant Regulatory Year.

The line items and figures are sourced from the Maintenance Expense and Operating Expense templates of the respective Regulatory Year's Annual Regulatory Accounts. The Standard Control Services figures shown include Advanced Metering Infrastructure ("AMI") as per the AER's guidance.

Table 3.2 Opex consistency: Table 3.2.1 Opex consistency - current cost allocation approach

This table was completed as there was a material change in the Annual Regulatory Accounts reporting requirements across the Regulatory Years covered by the Reports.

The preparation methodology and estimated information is consistent with the approach discussed below in relation to Table 3.2.2.

Table 3.2 Opex consistency: Table 3.2.2 Opex consistency - historical cost allocation approaches

Opex has been allocated in accordance with the categories required and in accordance with the requirements of the CAM, the Annual Regulatory Accounts and the Annual Reporting Requirements that were in effect for the individual Regulatory Year. The Opex categories presented in this table are not intended to be mutually exclusive or collectively exhaustive. The Standard Control Services figures shown include Advanced Metering Infrastructure ("AMI").

Preparation Methodology:

Using data extracted from the Annual Regulatory Accounts and information from the financial system, operating expenses were allocated into the categories requested. In order to perform this allocation, all cost information was extracted from the financial system by cost ledger code. Each code was reviewed by a suitable expert and, where possible, a one-to-one relationship was identified between the ledger cost code in the financial system and the regulatory category in Table 3.2.2.

For those ledger cost codes where a one-to-one relationship with a regulatory category in Table 3.2.2 could not be identified, the costs associated with that cost code were allocated to the various regulatory categories based on the most appropriate causal allocator as identified through the Activity Based Costing Survey process undertaken in accordance with the CAM.

Any costs which are not applicable in accordance with the regulatory accounting guidelines such as Interest, Income Tax Expense and contestable activities are excluded from the allocation process.

Estimated Information:

Transmission Point Planning Opex has been estimated. The wages of the employees undertaking these activities has been apportioned based on approximate time spent as determined by Management. The calculation was performed based on 2013 labour data and discounted back (across the Regulatory Years) using the consumer price index as applicable in each of the Regulatory Years – as an approximation of the labour escalation.

Table 3.3 Provisions

Provisions are recognised when SPI Electricity has a present legal or constructive obligation as a result of past events, it is more likely than not that an outflow of resources will be required to settle the obligation, and the amount of the provision can be measured reliably. Provisions are not recognised for future operating losses.

The amount recognised as a provision is the best estimate of the consideration required to settle the present obligation at the relevant reporting date, taking into account the risks and uncertainties surrounding the obligations. Where a provision is measured using the cash flows estimated to settle the present obligation, its carrying amount is the present value of those cash flows.

For all Regulatory Years, financial information on provisions for Standard Control Services has been reported in accordance with the requirements of the CAM and the Annual Regulatory Accounts that were in effect for the relevant Regulatory Year. The Standard Control Services figures presented include AMI.

Provisions have been separately presented based on the nature of the provision and allocated between an Opex component and a Capex component based on the classification of the underlying cost associated with the provision. Financial information on provisions reconciles to the reported amounts for provisions in the Annual Regulatory Accounts for each Regulatory Year.

Preparation Methodology:

Provision - Doubtful Debts, Provision - Uninsured Losses, Provision – Environmental Provisions, Provision - License/Regulatory Fees, Provision - Customer Rebates and Provision - Miscellaneous

For the 2011 to 2013 Regulatory Years, data has been extracted from the Annual Regulatory Accounts. For the 2006 to 2010 Regulatory Years, total movements in provisions was obtained from the Annual Regulatory Accounts and supplemented with information from the financial system to derive provision amounts. Information disclosed in relation to the above provisions is considered ‘actual information’.

The opening balance for Provision - Miscellaneous of $957,000 in the 2011 Regulatory Year does not agree to the closing balance of ($100,000) in the 2010 Regulatory Year due to a change in the classification for unpaid cross-boundary network charges from Excluded Services (now known as Alternative Control Services) to Standard Control Services as determined by the AER and reported as such in the Annual Regulatory Accounts.

Provision - Superannuation and Provision - Employee Entitlements

For the 2011 to 2013 Regulatory Years 'Amounts used during the period' and 'Unused amounts reversed during the period' have been disclosed as 'actual information' for both the Opex and Capex components as the data was extracted from the Annual Regulatory Accounts for the respective Regulatory Years.

All other information disclosed under Provision - Superannuation and Provision - Employee Entitlements is considered 'estimated information' due to the preparation approach outlined below. To derive the estimates, information was sourced from the financial system and supplemented with internal allocation models based on Activity Based Costing surveys.

In relation to variable DOPEX0305H in Provision – Superannuation, this represents the actuarial gains and losses from the defined benefit plan and should not be allocated between Opex and Capex as the amount is recognised against retained profits. However, in order to comply with the requirements of the AER's template, this allocation has been made.

Due to the amendments to AASB 119 *Employee Benefits* from 1 January 2013, the opening balance of Provision - Superannuation has been restated. Therefore, the opening balance of the provision as at 1 January 2013 do not agree to the closing balance of the provision in the 2012 Regulatory Accounts.

<u>Estimated Information</u>:

In relation to Provision - Employee Entitlements and Provision - Superannuation, the split between the Opex component and the Capex component was estimated for the 2006 to 2010 Regulatory Years. This was required as this data is not separately captured in the financial system. To determine the proportion of these provisions that should be classified as Capex, SPI Electricity has used the results from the SP AusNet Group quarterly capitalised overhead model which calculates the proportion of labour costs to be capitalised. The quarterly capitalised overhead model uses results from the quarterly Activity Based Costing surveys which provide the percentage split of management effort between all of SP AusNet's regulated and unregulated networks as well as between Opex and Capex. For the 2006 to 2008 Regulatory Years, the results from the quarterly capitalised overhead model were not readily available. Therefore, the average capex labour ratio over the 2009 to 2013 Regulatory Years have been applied to the 2006 to 2008 Regulatory Years as SPI Electricity's operations have been largely stable from the 2006 Regulatory Year, with no significant changes in its operations.

For Provision for Employee Entitlements, there is an increase in the provision associated with the passage of time. This increase has not been shown as it is not considered material.

Table 3.4 Opex for high voltage customers

Opex for high voltage customers has been reported based on the amount of Opex that would have been incurred in maintaining the electricity distribution transformers which are owned by high voltage customers.

Preparation Methodology:

Actual Information is unavailable, therefore an estimate has been derived based on the Opex incurred for operating similar MVA capacity Distribution Transformers within the network. SPI Electricity has high voltage customers who are supplied electricity at the higher voltage ratings of 6.6kV, 12kV and 22kV as well as sub transmission customers who are supplied electricity at 66kV.

The estimate has been calculated as the total cost of maintaining all owned transformers, divided by the number (units) of owned transformers. The resultant average cost is multiplied by the number of customers. This calculation relies on the assumption that Opex for high voltage customers is in line with Opex incurred for similar activities by SPI Electricity.

Estimated Information:

For customers who are supplied electricity at 6.6kV, 12kV and 22kV, average unit cost is derived based on SPI Electricity's estimated cost to maintain high voltage distribution substations, apportioned based on the capacity and number of substations.

It should be noted that this is an estimate based on SPI Electricity's estimated cost to maintain substations. It has been assumed that the cost of maintaining each type of substation (for example mounted substations, kiosk substations, ground type and indoor) is identical as maintenance costs are not available by substation type. It has also been assumed that the customer substations are similar in design to SPI Electricity's substations. This is considered a reasonable assumption as substation designs across Victoria are generally similar.

As a licensed distribution company operating under an Electricity Safety Management Scheme (ESMS), SPI Electricity has significant economies of scale. Therefore, a customer would spend more on average to maintain a substation. Hence, an additional calculation is done to scale up the unit cost based on what a customer may be expected to pay to maintain a larger substation (e.g. 500kV). An average unit cost has then been applied to estimate the total Opex associated with these customers.

Among the customers who are supplied electricity at 66kV, one is similar in size to that of a typical SPI Electricity zone substation, and as such, the unit cost is estimated to be similar to SPI Electricity's average Opex cost for a typical zone substation. For the other 66kV customers that are lesser in size, their average Opex cost is assumed to be half of that of a typical SPI Electricity zone substation – reflecting the reduction in the size of the substation and a reduction in the complexity of the associated maintenance costs.

Information was obtained from the financial system and the billing system. Information from the 2012 Regulatory Year was used as basis to estimate the data required as it was the most recently available information. The 2012 information obtained was applied to all Regulatory Years, adjusted based on customer numbers and the Consumer Price Index in the respective Regulatory Years. This is considered to be Management's best estimate based on the data available.

4. Assets (RAB)

The Regulated Asset Base ("RAB") values have been prepared and reported as per SPI Electricity's interpretation of the AER instructions set out in Section 4 of the RIN Instructions and Definitions ("RIN I&Ds").

Consistent with the instructions outlined in the RIN I&DS, the AER Final Decision SP AusNet Distribution determination 2011–15 (and specifically the published roll forward model) has been used as the basis for the RAB values as this is the latest AER Decision to incorporate actual information.

The accounting policies adopted by SPI Electricity in relation to capex (the only regulatory accounting input into the RAB) have not materially changed during any of the Regulatory Years covered by the Reports.

Table 4.1 Regulatory Asset Base Values

The RAB values have been prepared and reported as per SPI Electricity's interpretation of the AER instructions set out in Section 4 of the RIN I&Ds.

Preparation Methodology:

The AER Final Decision SP AusNet Distribution Determination 2011–15 roll forward model has been used as the basis for the RAB Values as this is the latest AER Decision to incorporate actual information. This model incorporates actual data up to and including the 2010 Regulatory Year. For the 2011 to 2013 Regulatory Years, the 2010 information has been rolled-forward using a combination of forecast and actual data. Forecast data applies to the straight-line depreciation values reported at DRAB0103, which represent forecast straight-line depreciation per 2011-15 Final decision (expressed in real 2010 dollars) adjusted for actual inflation. Data on actual additions and disposals have been reconciled to the Annual Regulatory Accounts for the 2006 to 2013 Regulatory Years.

In respect of actual additions for the purposes of RAB roll forward under Standard Control and Network Services, these values include a 6-month nominal WACC allowance as prescribed under the Regulatory Framework.

The roll forward model RAB includes the effects of an adjustment performed at the end of the 2010 Regulatory Year to account for the difference between actual and forecast Capex and the foregone return on Capex difference during the 2005 to 2010 regulatory control period. This adjustment is outlined in the AER Final Decision SP AusNet Distribution determination 2011–15. SPI Electricity does not consider this adjustment to be a revaluation (and therefore to be excluded) as defined in the RIN I&Ds. The adjustment has been made against the 2010 Closing RAB and 2011 opening RAB in accordance with guidance received from the AER. Due to this adjustment, Tables 4.1 and 4.2 do not satisfy the Roll Forward formula in the 2010 Regulatory Year (i.e. 2010 closing RAB does not equal 2010 opening RAB plus regulatory depreciation, additions and disposals).

Estimated Information:

SP AusNet considers that the proportion of the distribution assets that are dedicated connection assets is small. We have assumed the customer contribution has more than fully funded customers' dedicated assets. Therefore, subject to the removal of metering and public lighting assets, the capex included in the Standard Control Services and the Network Services Tables is equal.

Table 4.2 Asset value Roll forward

The disaggregated RAB values have been constructed as per SP AusNet's interpretation of the AER instructions set out in Section 4 of the RIN I&Ds.

Over the relevant Regulatory Years, SPI Electricity has recorded assets in the RAB and in the Annual Regulatory Accounts in asset classes that do not allow a direct attribution into the AER's economic benchmarking RAB Asset classes for the majority of assets.

Therefore, where direct attribution is not possible, SP AusNet has utilized the standard approach outlined Section 4.1.1 of the RIN I&Ds.

Preparation Methodology:

Information has been sourced from Asset Management Systems, 2012 Replacement Expenditure ("Repex") model (model template provided by the AER), the Distribution determination 2011–15, and Annual Regulatory Accounts.

The following process was followed:

1. Split between Standard Control Services, Network Services, and Alternative Control Services:
    a. Network Services excludes public lighting and meters as instructed by the AER
    b. Standard Control Services include only public lighting from the "sunk asset base"- prior to 2005, when public lighting was part of Standard Control Services. The AER has instructed to leave the value of the sunk asset base as part of Standard Control Services column, but not network services.
    c. Alternative Control Services – only public lighting assets post 2005 are included in this category.
2. Table 4.1 was directly disaggregated into the available RAB categories from the Roll Forward Model (column 1 in the table below):

Table RAB1

Roll Forward RAB categories	Benchmarking RIN categories
Distribution	Overhead network assets less than 33kV (wires and poles)
	Underground network assets less than 33kV (cables)
	Distribution substations including transformers
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
Meters	Meters
Public Lighting	"Other" assets with long lives
Non Network, IT and SCADA assets	"Other" assets with short lives

1. Physical asset data, including unit counts and replacement costs, has been taken from the 2012 Repex model. The 2012 Repex model, built in 2013 from final 2012 asset data, is the most recently completed Repex model and used data reported in 2012 Regulatory accounts. This repex data was used to determine weightings for disaggregating Roll Forward RAB categories in column 1 (above) to those in column 2 (above). The Repex model provides the best available data for performing the RAB allocation as it contains data on asset volumes, asset lives and replacement costs on a consistent basis.
2. The allocation applied to aggregate Repex categories to the Benchmarking RIN categories is as per the table below. Engineering assessment was the basis for determining to which of the Benchmarking categories each of the asset types in the Repex model belonged to. Where it was not possible to determine based on the name for the asset type (e.g. whether poles were assets for greater than 33kV), assumptions were made as detailed below.

Table RAB2

Roll forward RAB categories	**Benchmarking RIN categories**	**Repex**	**Share of RAB category**
Distribution (assets less than 33kV)	Overhead network	Includes poles, crossarms, conductor and services. • Cross arm assets are distinguishable in Repex between <33kV and >33kV. This share is used to allocate other categories. • Poles – assumes share is same as cross arms (94%). • Conductor – assumes total volume is same as share of cross arms. 100% ABC and HV Steel. Remainder of other conductor categories (ACSR, AAC and CU) that are not allocated to overhead >33kV (see below). • Services – 100% are <33kV	51%
	Underground network	Includes HVXLPE, LVXLPE, HV Paper lead, and underground services.	33%
	Distribution substations including transformers	Includes Distribution transformers, distribution switchgear, and distribution 'other assets'.	16%
Sub-transmission (assets 33kV	Overhead network	Includes poles, crossarms and conductor Refer to notes for <33kV. • Conductor – total share by volume is based on	34%

and above)		share for crossarms. Allocation by conductor type is: 53% AAC, 47% ACSR and 1% Copper based on analysis of asset data (survey performed by external expert in prior 5 years).	
	Underground network	No underground	0%
	Zone substations and transformers	Includes zone transformers, zone switchgear, and zone 'other assets'.	66%

1. To disaggregate the Roll Forward RAB categories using the physical assets, depreciated replacement costs for Benchmarking RIN categories have been calculated using the following formula:

   No. of Units x Unit Replacement Cost x Remaining Life/Standard Life

   and then the weightings based on these values are used to split the RAB categories into the asset categories in table 4.2 (column 2, Table RAB2, above). Units are from asset data in the Repex model. Unit replacement costs and standard lives are based on engineering assessment. Remaining life is calculated in the Repex model based on installation date and standard life.

2. The 2012 weightings were applied backwards to 2009 (and forwards to 2013) to estimate the RAB splits for other years. Actual expenditures were not available in the required categories to determine the historical splits using the roll-forward framework.

Table 4.3 Total disaggregated RAB asset values

Preparation Methodology:

The total disaggregated RAB values were calculated as the average of the Opening Value and Closing Value for each categorisations of assets presented in Table 4.2.

Table 4.4 Asset lives

Preparation Methodology:

Calculations are based on data from Asset Management Systems. The data utilised was summated using the AER's Repex model based on the 2012 Annual Regulatory Accounts data.

Table 4.4.1 Asset Lives – estimated service life of new assets

The 'estimated service life of new assets' or 'weighted average life' ("WAL") of the asset group or category is completed using the total replacement cost as the weighting. The weighting assumption is taken from the AER Expenditure Forecast Assessment Guideline:

Asset class specific assumptions are:

- DRAB1401: Overhead is assumed to be an average of the summary provided for poles and conductors on the distribution network.
- DRAB1402: Underground was as per Repex model.
- DRAB1403: Distribution substations included all distribution transformers
- DRAB1404: Was calculated as per the average of all conductor assets, wood class 1 and concrete poles which also include sub transmission towers.

    - It is assumed that the proportion of wood class 1 and concrete pole assets would be reflective of assets carrying circuits above 33kv.
    - It has been assumed that the average life of 66kv conductors is consistent with the average of the pool of conductors. This assumption is required as 66kv conductor assets are not separately captured in the Repex model.
- DRAB1406: Data taken from Repex model primarily includes Power Transformers. Data also includes station service and instrument transformers.

The above methodology was able to be utilised for assets in variables DRAB1401-DRAB1406. Engineering technical expertise was applied in determining WALs in the Repex model.

For variables DRAB1401 to DRAB 1406, the WALs determined for the 2012 Regulatory Year were recorded for all other Regulatory Years on the basis that the WALs are not expected to materially change over this time period. That is, it is assumed the asset profile does not change materially over time.

For variables DRAB1407 'Meters' and DRAB1408 'Other assets with long lives', over the period for which data are provided, no new assets were being added to the Standard Control Services ("SCS") RAB. For Meters this was due to the roll out of the AMI program in Victoria. The only assets in DRAB1408 were Public Lighting, which is no longer a Standard Control Service. For the new public lighting RAB in DRAB1408, a proxy standard and residual life was generated from the forecast capex profile. Weightings used the depreciated nominal capex values over time.

In the case of both these asset categories, the regulatory lives from the Essential Services Commission's ("ESC's") regulatory model were assumed to be reflective of the service lives of assets in the category. Similarly, the residual lives were calculated on the basis that they were rolled back from the year when all assets were removed from the SCS asset base.

For the variable DRAB1409 'Other assets – Short lives', the asset lives in the AER's Roll Forward Model for the 2011-15 Distribution Determination we assumed to accurately reflect the physical asset lives. The weighted average residual life was calculated as the weighted average residual life for the IT and Non-network – Other RAB categories, using 2011 opening RAB values as to perform the weighting.

Table 4.4.2 Asset Lives – estimated residual service life

The 'estimated residual service life', or 'weighted average remaining life' ("WARL") of the asset group or category, is completed by using the total replacement cost as the weighting. The weighting assumption is taken from the AER expenditure forecast assessment guideline.

Residual Lives are based on the same assumptions mentioned above under *Table 4.4.1 Asset Lives – estimated service life of new assets*.

Estimated Information:

Refer to estimates and assumptions discussed above.

5. Operational Data

Table 5.1 Energy delivery

Energy delivered is the amount of electricity transported out the network in the relevant period and is measured as the energy metered (or estimated) at the customer charging location.

Preparation Methodology:

- 5.1 Total Energy Delivered: This data was obtained directly from the Annual Regulatory Accounts.

- 5.1.1 Energy delivery by chargeable quantity: For Regulatory Years 2011 to 2013, tariff quantity data sourced from the Annual Regulatory Accounts was allocated to the categories required by assigning tariffs to a specific chargeable quantity. For Regulatory Years 2006 to 2010, data obtained from Tariff Quantity Schedules (included in Annual Regulatory Accounts and Tariff Submissions) was allocated to the categories required, applying the same methodology as used for the data in the 2011 to 2013 Regulatory Years.

  Energy delivered to customers on tariffs that do not have peak, shoulder or off-peak periods was reported in 'Energy Delivery where time of use is not a determinant' [DOPED0201].

- 5.1.2 Energy – received from TNSP and other DNSPs by time of receipt: The data required was calculated based on information extracted directly from the billing system.
  Total energy received has been included in DOPED0304 'Energy received from TNSP and other DNSPs not included in the above categories' as it is not possible to allocate the available energy received information into the defined on-peak, shoulder and off-peak times without a specific definition of those time periods (as SPI Electricity has multiple peak and off-peak time periods across its tariff classes, it is not possible to determine which 'peak' time (for example) should be used.

- 5.1.3 Energy – received into DNSP system from embedded generation by time of receipt: The data required was calculated based on information directly extracted from the billing system.

  Total energy received from non-residential embedded generation has been included in DOPED0404 'Energy received from embedded generation not included in above categories from non-residential embedded generation' as it is not possible to allocate the available energy received information into the defined on-peak, shoulder and off-peak times without a specific definition of those time periods.

  Total energy received from residential embedded generation has been included in DOPED0408 'Energy received from embedded generation not included in above categories from residential embedded generation' as it is not possible to allocate the available energy received information into the defined on-peak, shoulder and off-peak times.

- 5.1.4 Energy grouping – customer type or class: For Regulatory Years 2011 to 2013, tariff quantity data sourced from the Annual Regulatory Accounts (which was ultimately sourced from customer billing data) was allocated to the categories required by assigning each tariff to a specific customer type or class. For the Regulatory Years 2006 to 2010, data obtained from Tariff Quantity Schedules (included in Annual Regulatory Accounts and Tariff Submissions) was allocated into the categories required, applying the same methodology as used for the data in the 2011 to 2013 Regulatory Years.

Unmetered energy delivery was reported in 'Other Customer Class Energy Deliveries' [DOPED0505].

Table 5.2 Customer numbers

Distribution Customers for a Regulatory Year are defined as the average number of energised and de-energised National Meter Identifiers ("NMIs") in SPI Electricity's network in that year, plus unmetered customers but excluding extinct NMIs. The average is calculated as the average of the number of customers on the first day of the Regulatory Year and the last day of the Regulatory Year.

For unmetered customers, Customer Numbers are the sum of connections (excluding public lighting connections) that do not have a NMI and the energy usage for billing purposes is calculated using an assumed load profile (examples include bus shelters, security lighting and traffic signals where not metered). Public lighting connections are not included as unmetered customers.

Preparation Methodology:

The total average customer numbers were obtained from PowerOn system reports. The split of customer numbers into the prescribed categories was estimated as follows -

- Table 5.2.1 Distribution customer numbers by customer type or class: total average customer numbers were allocated into the prescribed customer types using a percentage allocation based on tariff classification data from Tariff Schedules (included in Annual Regulatory Accounts and Tariff Submissions).

  'Unmetered customer numbers' (DOPCN0105) was obtained directly from the New Connections Unmetered Supplies ("UMS") database for the 2007 to 2013 Regulatory Years. Unmetered customer numbers for the 2006 Regulatory Year was not available based on system data. This data has been estimated based on the number of unmetered customers in the 2007 Regulatory Year less the movement in unmetered customer numbers between 2007 and 2008. This estimate assumes the same number of unmetered customers were added (net of disconnections) in 2006 as were added in 2007. This is considered Management's best estimate based on the information available.

- Table 5.2.2 Distribution customer numbers by location on the network: Using data extracted from the Service Order Management System, the percentage of customers by the three feeder categories (Urban, Short Rural and Long Rural) was obtained for each Regulatory Year. These percentages were applied to the total average customer numbers per Table 5.2.1 to derive an estimate of distribution customer numbers by location on the network.

  The categorisations are based on the feeder locations (Urban, Short Rural and Long Rural) in the respective Regulatory Years.

Estimated Information:

The categorisation of customers in Table 5.2.1 (with the exception of 'Unmetered Customer Numbers' in the 2007 to 2013 Regulatory Years) and the categorisation of customers in Table 5.2.2 is considered estimated information due to the application of percentages to derive the requested data categorisations. Estimates used are considered to be Management's best estimate of the required information.

Table 5.3 System demand – Tables 5.3.1, 5.3.2, 5.3.3 and 5.3.4

Preparation Methodology:

- Table 5.3.1 Annual system maximum demand characteristics at the zone substation level

  Daily non-coincidental maximum demand data was extracted from OSI Pi. Using this information, the maximum demand day at each substation was identified. The attributes at the time of peak (MW, MVA, Date, Time) were determined for each zone substation for 2009-2013.

  30 minute maximum demand data was extracted from OSI Pi for each zone substation, providing daily coincidental maximum demand information (date, time). Using this information, the maximum MVA and the attributes at the time of peak (MW, MVA) were determined for each zone substation for 2009-2013.

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

  Non-coincident Summated Raw System Annual Maximum Demand:

  SPI Electricity has calculated demand based on National Energy Market Meter data supplied from the transmission business for 2010-2013. Data for 2009 was not available, so to populate this cell, the corresponding 2009 demand at the zone substation level (Table 5.3.1) was multiplied by a factor equating to the 2013 transmission connection point demand divided by the 2013 zone substation demand.

Coincident Raw System Annual Maximum Demand:

Information was sourced from the National Energy Market Meters (Both Terminal Station, Boundary and Generator Meters). The network meters have been reconciled with AEMO and SP AusNet's Protection department to ensure all applicable meters are accounted for in calculating the Maximum Demand on the network.

Daily coincidental maximum demand data was extracted for the network for all days in 2010-2013. Using this information, the maximum demand day was identified for each year. Using information described above, the yearly attributes at the time of peak (MW, MVA, Date, Time, Peak) was identified.

Data for 2009 was not available, so to populate this cell, the corresponding 2009 demand at the zone substation level (Table 5.3.1) was multiplied by a factor equating to the 2013 transmission connection point demand divided by the 2013 zone substation demand.

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

  Daily non-coincidental maximum demand data was extracted from OSI Pi. Using this information, the maximum demand day at each substation was identified. The attributes at the time of peak (MW, MVA, Date, Time) were determined for each zone substation for 2009-2013.

  30 minute maximum demand data was extracted from OSI Pi for each zone substation, providing daily coincidental maximum demand information (date, time). Using this information, the maximum MVA and the attributes at the time of peak (MW, MVA) were determined for each zone substation for 2009-2013.

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

  <u>Non-coincident Summated Raw System Annual Maximum Demand</u>:

  SPI Electricity has calculated demand based on National Energy Market Meter data supplied from the transmission business.

  Data for 2009 was not available, so to populate this cell, the corresponding 2009 demand at the zone substation level (Table 5.3.1) was multiplied by a factor equating to the 2013 transmission connection point demand divided by the 2013 zone substation demand.

  <u>Coincident Raw System Annual Maximum Demand:</u>

  Information was sourced from the National Energy Market Meters (Both Terminal Station, Boundary and Generator Meters). The network meters have been reconciled with AEMO and SP AusNet's Protection department to ensure all applicable meters are accounted for in calculating the Maximum Demand on the network.

  Daily coincidental maximum demand data was extracted for the network for all days in 2010-2013. Using this information, the maximum demand day was identified for each year. Using information described above, the yearly attributes at the time of peak (MW, MVA, Date, Time, Peak) was identified.

  Data for 2009 was not available, so to populate this cell, the corresponding 2009 demand at the zone substation level (Table 5.3.1) was multiplied by a factor equating to the 2013 transmission connection point demand divided by the 2013 zone substation demand.

Table 5.3 System demand – 5.3.5 Power factor conversion between MVA and MW

Preparation Methodology:

- Average overall network power factor conversion between MVA and MW (DOPSD0301) was calculated as DOPSD0107 divided by DOPSD0207.
- Average power factor conversion for SWER lines (DOPSD0304) was estimated based on 2014 data from the SCADA system. 2014 data is considered more accurate and complete than the available 2013 information and is considered the best estimate of the information required.
- Average power factor conversion for 22 kV lines (DOPSD0305) was estimated based on 2014 data from the SCADA system. 2014 data is considered more accurate and complete than the available 2013 information and is considered the best estimate of the information required. The 2014 data used was scaled down for each Regulatory Year using the ratio of variables DOPSD0305 to DOPSD0307 from the following Regulatory Year.
- The 'Average power factor conversion for 66 kV lines' (DOPSD0307) was estimated as variable DOPSD0101 divided by variable DOPSD0201 for all Regulatory Years.

Estimated Information:

Variable DOPSD0301 is considered estimated information for the 2006 to 2011 Regulatory Years due to estimates included in variables DOPSD0107 and DOPSD0207 in these years.

Estimates were required in relation to power factors reported (variables DOPSD0304, DOPSD0305 and DOPSD0307) as system generated information was not available for all Regulatory Years in the categorisation required.

The estimated information is considered Management's best estimate based on the data available.

Table 5.3 System demand – 5.3.6 Demand supplied (for customers charged on this basis) – MW measure

Preparation Methodology:

Table 5.3.6 is not applicable to SPI Electricity as all demand customers are billed on MVA not MW.

Table 5.3 System demand - 5.3.7 Demand supplied (for customers charged on this basis) – MVA measure

Preparation Methodology:

'Summated Chargeable Contracted Maximum Demand' (DOPSD0403) information was obtained from customer billing data for all Regulatory Years.

'Summated Chargeable Measured Maximum Demand' (DOPSD0404) was obtained from customer billings for the 2011 to 2013 Regulatory Years. For the 2006 to 2010 Regulatory Years, the information was estimated based on the 2013 ratio of 'Summated Chargeable Contracted Maximum Demand' (DOPSD0403) to 'Summated Chargeable Measured Maximum Demand' (DOPSD0404).

Estimated Information:

Summated Chargeable Measured Maximum Demand variables were estimated for the 2006 to 2010 Regulatory Years. Estimates made assume that the ratio of Summated Chargeable Contracted Maximum Demand' to 'Summated Chargeable Measured Maximum Demand' remains consistent each year and is considered management's best estimate based on the available data.

6. Physical Assets

Table 6.1.1 Overhead network length of circuit at each voltage and Table 6.1.2 Underground network circuit length at each voltage

Network capacity variables are reported for the whole network including overhead power lines, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers. Network also includes distribution feeders and the low voltage distribution system but excludes the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.

In relation to Table 6.1.1 'Overhead network length of circuit at each voltage' and Table 6.1.2 'Underground network circuit length at each voltage', circuit length is calculated from the Route length (measured in kilometres) of lines in service, where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines. The length does not take into account vertical components such as sag.

Preparation Methodology:

For regulatory years 2006, 2008 and 2010 to 2013, data was directly extracted from internal periodic system reports (from the Asset Management System (SDME)) and allocated into the categories required taking into consideration the inclusions and exclusions discussed above. The information provided is considered 'actual information' as it was extracted from the system, however it is noted that the system data has been subject to data cleansing over the Regulatory Years.

Internal reports (from the Asset Management System) for the 2007 and 2009 Regulatory Years are not available and cannot be generated as the system is live. For these years, data is available on a financial year basis (year ending 31 March) using information provided for Energy Supply Association of Australia Benchmarking Survey Reports. Using this information, an estimate for the 2007 and 2009 Regulatory Years was derived.

Estimated Information:

For the 2007 Regulatory Year, a simple average calculation of data as at 31 March 2007 and 31 March 2008 was performed to derive an estimate of the 2007 variables. The 31 March 2007 information was not disaggregated into the kV category levels required. This categorisation was estimated using a percentage allocation methodology consistent with known category levels for the year ended 31 March 2008.

For the 2009 Regulatory Year, a simple average calculation of data as at 31 March 2009 and 31 March 2010 was performed to derive an estimate of the 2009 variables.

Management considers these calculations as the best estimate of the required data for 2007 and 2009.

Table 6.1.3 Estimated overhead network weighted average MVA capacity by voltage class and Table 6.1.4 Estimated underground network weighted average MVA capacity by voltage class

Weighted average capacities have been reported for both the overhead and underground network in the required voltage classes.

Preparation Methodology:

Data for the 2013 Regulatory Year was sourced from the Asset Management System - including the conductor voltage (“Volts”), current rating (“Amps”) and line length in kilometres (“length”) for each section of line. Actual ratings were used which are considered to be reflective of operational ratings.

The weighted average was calculated based on the following methodology:

$$\frac{\text{Line 1: (length * Volts * Amps) + Line 2: (length * Volts * Amps) + Line 3: (length * Volts * Amps) etc.}}{\text{(Line 1 length + Line 2 length + Line 3 length etc.)}}$$

For three phase lines each group in the numerator has also been multiplied by √3.

Data for the 2006 to 2012 Regulatory Years has been estimated as being consistent with the overhead and underground network weighted average MVA calculated for the 2013 Regulatory Year. An estimate is required to be made as the complete requisite data is not available for the 2006 to 2012 Regulatory Years. This estimate assumes that the mix of line lengths and current ratings that existed in 2013 is representative of the mix in previous Regulatory Years at each voltage level. Additionally, this estimation approach assumes that there have been no significant policy changes in the types (ratings) and spans of conductor being installed across these distribution voltages.

Estimated Information:

Refer to estimates and assumptions above in relation to the 2006 to 2012 Regulatory Years. The estimated information is considered to be Management’s best estimate based on the available information.

Table 6.2 Transformer Capacities Variables

Table 6.2.1 Distribution transformer total installed capacity

A Distribution Transformer is a transformer that provides the final voltage transformation in the electricity distribution system, stepping down the voltage used in the distribution lines to the level used by the customer.

The total installed Distribution Transformer capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (e.g. 132kV, 66kV, 22kV or 11kV) distribution level. The capacity measure is the normal nameplate continuous capacity/rating (including forced cooling and other factors used to improve capacity).

Distribution Transformer capacity owned by SPI Electricity and owned by High Voltage Customers has been reported.

Cold spare capacity is the capacity of spare transformers owned by SPI Electricity but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and / or making of connections would require manual intervention at the site of use.

Preparation Methodology:

Information in relation to 'Distribution Transformer capacity owned by SPI Electricity' (DPA0501) was sourced from the Asset Management System using plant utilisation reports. Total capacity of transformers has been calculated by extracting only the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer.

'Distribution Transformer capacity owned by High Voltage customers' (DPA0502) was estimated based on Capacity charges that are made to customer accounts using data obtained from the Annual AER Tariff Submissions. The data is based on the capacity charged to customers originally sourced from the billing system.

The data is based on what is charged to the customer at a peak rate and assumes this calculation as a maximum capacity. This is not what the customer has installed and will underestimate the actual installed rated capacity.

'Cold Spare Capacity' (DPA0503) for the 2009 to 2013 Regulatory Years was sourced from a stock on hand report generated by the Asset Management System. The reports used were generated on 1 January of the following Regulatory Year e.g. the report generated as at 1 January 2014 was used to provide the Cold Spare Capacity as at 31 December 2013, etc.

System data was not available for the 2006 to 2008 Regulatory Years. The data for 2006 to 2008 was estimated as the average Cold Spare Capacity across the 2009 to 2013 Regulatory Years. This is considered Management's best estimate based on the information available.

Estimated Information:

Refer to estimates and assumptions discussed above. The estimated information provided is considered Management's best estimate based on the available data.

Table 6.2.2 Zone substation transformer capacity

‘Total installed capacity for first step transformation where there are two steps to reach distribution voltage’ (DPA0601) and ‘Total installed capacity for second step transformation where there are two steps to reach distribution voltage’ (DPA0602) has been reported as zero value on the basis that SPI Electricity does not have installed capacity with more than one step or transformation.

‘Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage’ (DPA0603) has been reported where there is only a single step of transformation.

‘Cold Spare Capacity of zone substation transformers included in DPA0604’ (DPA0605) has reported total Cold Spare Capacity included in total zone substation transformer capacity.

‘Total zone substation transformer capacity’ (DPA0604) was calculated as the sum of variables DPA0601, DPA0602, DPA0603 and DPA0605.

Preparation Methodology:

Table 6.2.2 was prepared on an asset by asset basis using information sourced from the Asset Management System. The ratings assumed were based on the nameplate capacity of the transformer unit.

Table 6.3 Public lighting

Public lighting luminaires and Public lighting poles reported include both assets owned and assets operated and maintained (but not owned). Only poles that are exclusively used for public lighting have been included.

Preparation Methodology:

In relation to the number of Public lighting luminaires [DPA0701] - a report generated in the AMFM spatial mapping system was used to provide the data required for all Regulatory Years. Numbers reported agree to Annual Electricity Performance Reports. No adjustments were required to the system generated reports.

In relation to the number of Public lighting poles [DPA0702] - data was extracted directly from the AMFM spatial mapping system for the 2013 Regulatory Year.

For the 2006 to 2012 Regulatory Years, reliable system data was not available. This information was estimated using the 2013 data reduced by the annual change of public lighting luminaires multiplied by an average percentage of luminaries to poles.

Estimated Information:

Public lighting pole numbers were estimated for the 2006 to 2012 Regulatory Years. The information provided is considered Management’s best estimate of public lighting pole numbers based on the information available.

7. Quality of Service

Table 7.1 Reliability

Reliability Information is reported for unplanned interruptions which is an interruption due to an unplanned event. An unplanned event is considered an event that causes an interruption where the customer has not been given the required notice for the interruption or where the customer has not requested the outage.

An interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network, including generation facilities and transmission networks, of more than 60 seconds, including outages affecting a single premise.

The customer interruption starts when recorded by equipment or, where such equipment does not exist, at the time of the first customer call relating to the network outage. An interruption may be planned or unplanned, momentary or sustained. Subsequent interruptions caused by network switching during fault finding are not included. An interruption ends when supply is again generally available to the customer.

System Average Interruption Duration Index (“SAIDI”) is the sum of the duration of each unplanned sustained Customer interruption (in minutes) divided by the average number of Distribution Customers. SAIDI excludes momentary interruptions (interruptions of one minute or less).

System Average Interruption Frequency Index (“SAIFI”) is the total number of unplanned sustained Customer interruptions divided by the average number of Distribution Customers. Unplanned SAIFI excludes momentary interruptions (interruptions of one minute or less).

Whole of network SAIDI and SAIFI is the system wide SAIDI and SAIFI.

Excluded Outages are:

- load shedding due to a generation shortfall;
- automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition;
- load shedding at the direction of the Australian Energy Market Operator or a system operator;
- load interruptions caused by a failure of the shared transmission network;
- load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning; and
- load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.

Customer numbers were calculated as the average of the January and December customer counts for each Regulatory Year.

The definitions and data used are consistent both with the AER's Distribution STPIS Guidelines and the AER Final Decision for the 2011-15 Electricity Distribution Price Review.

Table 7.1.1 Inclusive of Major Event Days

Preparation Methodology:

Information was sourced from AER Annual Regulatory Accounts (2011 – 2013), Annual Electricity Performance Reports (2006 – 2010) and from data in the Service Order Management System.

Whole of network unplanned SAIDI – 'Unplanned Minutes-Off-Supply' were obtained from each AER Annual Regulatory RIN Report or Annual Electricity Performance Report and divided by the average number of distribution customers connected to the network for that year.

Whole of network unplanned SAIDI with excluded outages - the annual total 'Unplanned Minutes-Off-Supply' from network events that are illegible for exclusion according to Section 3.3 of the 2011-2015 EDPR STPIS were obtained from the PowerOn network outage historical data and divided by the average number of distribution customers connected to the network for that year. The transmission-related minutes were subtracted from the 'Whole of network unplanned SAIDI' in Table 7.1.1.

Whole of network unplanned SAIFI - 'Unplanned Interruptions' were obtained from each AER annual RIN Report or Annual Electricity Performance Report and divided by the average number of distribution customers connected to the network for that year.

Whole of network unplanned SAIFI with excluded outages - the annual total 'Unplanned Interruptions' from network events that are illegible for exclusion according to Section 3.3 of the 2011-2015 EDPR STPIS was obtained from the PowerOn system network outage historical data and divided by the average number of distribution customers connected to the network for that year. The transmission-related interruptions were subtracted from the 'Whole of network unplanned SAIFI' in Table 7.1.1.

Table 7.1.2 Exclusive of Major Event Days

Preparation Methodology:

Historical outage data from the Service Order Management System was used to calculate the daily unplanned SAIDI and SAIFI from 2008 to 2013. Other required information was sourced from AER Annual RIN Reports (2011 – 2013) and Annual Electricity Performance Reports (2006 – 2010).

The Major Event Days ("MED") threshold was calculated for the 2013 Regulatory Year from the daily Unplanned SAIDI data between Regulatory Years 2008 and 2012 (5 years) using the annual AER RIN Template MED calculator. The calculated MED threshold was applied as the threshold for all Regulatory Reporting Years in accordance with the AER Instructions and Definitions.

The MED dates to exclude for each year from 2008 to 2013 were identified using the calculated 2013 MED threshold. For each year, the unplanned SAIDI for all MED dates was summed. The same process was followed for unplanned SAIFI.

In relation to 'Whole of network unplanned SAIDI' and 'Whole of network unplanned SAIFI' - for each Regulatory Year, the summed unplanned SAIDI for all MED was subtracted from the Total SAIDI value in Table 7.1.1 (DQS0101) to obtain the SAIDI performance exclusive of the MED impact. The same process was followed for unplanned SAIFI.

'Whole of network unplanned SAIDI with excluded outages': for each year, the 'Whole of network unplanned SAIDI' in Table 7.1.2 and the 'Whole of network unplanned SAIDI excluding excluded outages' in Table 7.1.1 (DQS0102) was subtracted from the 'Whole of network unplanned SAIDI' in Table 7.1.1. The same process was followed for 'Whole of network unplanned SAIFI with excluded outages'.

Table 7.2 Energy not supplied

Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions and is reported exclusive of the effect of Excluded Outages.

Preparation Methodology:

The reported values of energy not supplied were obtained from the AER Annual RIN Reports (2011 – 2013), the Annual Electricity Performance Reports (2006 – 2010) and the Outage Management System.

An estimate was performed of the raw (not normalized) energy not supplied due to unplanned customer interruptions. The estimate was calculated based on average customer demand multiplied by the number of customers interrupted and the duration of the interruption. Average customer demand was determined from average consumption of customers on the feeder based on their billing history.

Estimated Information:

Estimates provided are considered Management's best estimate based on available information.

Table 7.3 System losses

System losses are the proportion of energy that is lost in the distribution of electricity from the transmission network to customers. It has been calculated as the difference between electricity imported and electricity delivered as a percentage of electricity imported.

Electricity imported is the total electricity inflow into the distribution network (including from Embedded Generation) less the total electricity outflow into the networks of the adjacent connected distribution network service providers or the transmission network.

Electricity delivered is the amount of electricity transported out of the network to customers as metered (or otherwise calculated) at the customer's connection. This is a system wide figure not a feeder level figure.

Preparation Methodology:

System losses are calculated as the sum of

> (DOPED0404 'Energy received from embedded generation not included in above categories from non-residential embedded generation' + DOPED0408 'Energy received from embedded generation not included in above categories from residential embedded generation' + DOPED0304 'Energy received from TNSP and other DNSPs not included in the above categories' - DOPED01 'Total energy delivered') divided by (DOPED0404 'Energy received from embedded generation not included in above categories from non-residential embedded generation' + DOPED0408 'Energy received from embedded generation not included in above categories from residential embedded generation' + DOPED0304 'Energy received from TNSP and other DNSPs not included in the above categories').

Table 7.4 Capacity utilisation

Capacity utilisation is a measure of the capacity of zone substation transformers that is utilised each year. The sum of non-coincident Maximum Demand at the zone substation level divided by summation of zone substation thermal capacity is reported.

Thermal capacity is the rated continuous load capacity of the zone substation (with forced cooling or other capacity improving factors included if relevant) being the lowest of either the transformer capacity or feeder exit capacity of the zone substation. Feeder exit capacity is the continuous rating.

Preparation Methodology:

Data was calculated as variable DOPSD0201 Non–coincident Summated Raw System Annual Maximum Demand divided by variable DPA0604 Total zone substation transformer capacity.

Estimated Information:

Data provided is considered estimated information due to estimates included in variable DOPSD0201.

8. Operating environment

Table 8.1 Density factors

'Customer Density' (DOEF0101) is the total number of customers divided by the route Line Length of the network.
'Energy Density' (DOEF0102) is the total MWh divided by the total number of customers of the network.
'Demand Density' (DOEF0103) is the kVA non-coincident Maximum Demand (at zone substation level) divided by the total number of customers of the network.

Preparation Methodology:

Information was sourced from prior year annual AER Reliability Performance Reports and the Asset Management System.

'Customer Density' (DOEF0101) - the total number of customers were obtained from annual AER Reliability Performance Reports. Total route lengths for both overhead ("OH") and underground ("UG") were obtained from the Asset Management System. The following formula was used to calculate Customer Density -

$$\frac{\sum Connected\ Customers}{\sum[HV\ OH\ line + HV\ UG\ Line](km)}$$

'Energy Density' (DOEF0102) was calculated as the 'Total Energy Delivered' in GWh (DOPED01) x 1000 divided by 'Total Customer Numbers' (DOPCN01).

'Demand Density' (DOEF0103) - the summated Feeder Maximum Demand ("MVA") and the summated the number of customers was obtained from annual AER Reliability Performance Reports. The following formula was used to calculate Demand Density -

$$\frac{Feeder\ Maximum\ Demand, kVA}{\sum Connected\ Customers}$$

Customer numbers were calculated as the average of the January customer count (of the active National Meter Identifiers ('NMIs'), de-active NMIs and unmetered connections) and the December customer count (active and de-active NMIs and unmetered connections).

Route lengths included in calculations were as at 31 December of each Regulatory Year.

Estimated Information:

'Customer Density' (DOEF0101) information for the 2006 to 2012 Regulatory Years is considered estimated information as the 'Route Line Length' (DOEF0301) variables included in the calculation of customer density were estimated for these Regulatory Years. Table 8.3 below provides information in relation to 'Route Line Length' estimates.

‘Demand Density’ (DOEF0101) information for all Regulatory Years is considered estimated information as the ‘Non–coincident Summated Raw System Annual Maximum Demand’ (DOPSD0201) variables included in the calculation of demand density were estimated for all Regulatory Years.

Data provided is considered Management’s best estimate based on available information.

Table 8.2 Terrain factors

***A. Rural proportion (DOEF0201)**:*

Rural proportion is the distribution route length classified as short rural or long rural in kilometers (“km”) divided by the total network line length.

Preparation Methodology:

Using historical line length data in Annual Performance Reports, the ratio of high voltage line lengths connected to Long and Short rural feeders to the total line length of the distribution network was calculated. The HV line length excludes sub-transmission (i.e. 66kV) and low voltage networks.

Estimated Information:

Estimates provided are considered Management’s best estimate based on available information.

B. Urban and CBD vegetation maintenance spans (DOEF0202), Rural vegetation maintenance spans (DOEF0203), Total vegetation maintenance spans (DOEF0204) and Total number of spans (DOEF0205)

Maintenance span is the network span that is subject to active vegetation management practices in the relevant year. Active vegetation management practices do not include inspection of vegetation maintenance spans - where ‘inspection’ is only for the purpose of identifying trees or other vegetation that require trimming or removal and includes vegetation scoping works.

Urban and CBD maintenance spans refers to CBD and urban areas that are subject to vegetation management practices in the relevant Regulatory Year. CBD and urban areas are consistent with CBD and urban customer classifications.

Rural maintenance spans refer to spans in rural areas that are subject to vegetation management practices in the relevant year. Rural spans include spans in short rural and long rural feeders.

Urban and Rural maintenance spans were determined using information extracted from the Vegetation Management system which was split into area category (Urban and Rural) using feeder data and further disaggregated into total spans and spans clear of vegetation. ‘Urban and CBD vegetation maintenance spans’ (DOEF0202) and ‘Rural vegetation maintenance spans’ (DOEF0203) were determined as PT1-PT365 per the system data (which denotes spans where vegetation maintenance is required in the next 365 days. DOEF0202 and DOEF0203 include only spans subject to action/cutting rather than inspection or assessment only.

‘Total Vegetation Maintenance spans’ (DOEF0204) was calculated as the sum of ‘Urban and CBD vegetation maintenance spans’ (DOEF0202) and ‘Rural vegetation maintenance spans’ (DOEF0203).

'Total number of spans' (DOEF0205) is the total count of spans in the network in the relevant Regulatory Year. The information for (DOEF0202), (DOEF0203), (DOEF0204) & (DOEF0205) was extracted from the Vegetation Management system and excludes 66kv Sub-Transmission lines for Urban and Rural feeders as SP AusNet cannot provide the classification for these lines. The omission of these lines represents a percentage of < 1% of total spans which SP AusNet believes is immaterial.

C. Average urban and CBD vegetation maintenance span cycle (DOEF0206) and Average rural vegetation maintenance span cycle (DOEF0207)

Maintenance span cycle refers to the planned number of years between which cyclic vegetation maintenance is performed for the relevant area. Information in relation to the average vegetation maintenance span cycles was obtained from the Vegetation Management system and also per the vegetation management plan.

D. Average number of trees per urban and CBD vegetation maintenance span (DOEF0208) and Average number of trees per rural vegetation maintenance span (DOEF0209)

The 'Average number of trees per maintenance span' includes only trees that require active vegetation management to meet its vegetation management obligations. It excludes trees that only require inspections and no other vegetation management activities are required to comply with the SPI Electricity's vegetation obligations.

The average number of trees per urban and rural vegetation maintenance spans was estimated. In 2009, a random sample (across the network) was performed of the total trees being maintained to preserve regulatory clearance space. Based on the sample results, a percentage of trees being maintained relative to spans was calculated. This percentage was applied to the total number of vegetation maintenance spans (for the Central, North and East regions) in 2013 to derive an estimate of the average number of trees in the 2013 Regulatory Year.

It has been assumed that the average number of trees in urban vegetation maintenance spans is consistent with the average number of trees in rural vegetation maintenance spans as the random sample did not distinguish between urban and rural data. Additionally, it has been assumed that the average number of trees per vegetation maintenance span in the current year is consistent with previous Regulatory Years.

Estimated Information:

Management considers the above estimates to be the best estimates of the information required based on available data.

E. Average number of defects per urban and CBD vegetation maintenance span (DOEF0210) and Average number of defects per rural vegetation maintenance span (DOEF0211)

Defects are any recorded incidence of noncompliance with a NSP's vegetation clearance standard and include vegetation outside the standard clearance zone that is recognised as hazardous vegetation and would normally be reported as requiring management under inspection practices. Defects on a vegetation span are recorded as one, regardless of the number of defects on the span.

Information to calculate average number of defects per urban and CBD maintenance span was extracted from the Vegetation Management system system and Hazard Tree Databased and excludes 66kv Sub-Transmission lines for Urban and Rural feeders as SP AusNet cannot provide the classification for these lines. The omission of these lines represents a percentage of < 1% which SP AusNet believes is immaterial. Total number of defects was calculated as the number of PT1 and PT30 spans which are vegetation maintenance spans requiring action in the next 30 days. To derive an estimate of the Average number of defects, the total number of defects was divided by the number of vegetation maintenance spans requiring action/cutting. This calculation was performed for both CBD and Rural spans.

F. Tropical Spans (DOEF0212)

Tropical spans are the approximate total number of urban and rural Maintenance Spans in the Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology Australian Climatic Zones map (based on temperature and humidity). There are no Tropical Spans in SPI Electricity's urban and rural Maintenance Spans.

G. Standard Vehicle Access (DOEF0213)

Standard vehicle access refers to areas which are serviced through made roads, gravel roads and open paddocks (including gated and fenced paddocks). It excludes areas only accessible by a two wheel drive vehicle.

A calculation was performed of spans which needed a climbing party to enable access (during the 2013 regulatory year) divided by the total number of spans on the network. This data was obtained from the Vegetation Management System. The total 2013 route line length in kilometers (DOEF0301) was multiplied by (the percentage calculated above) to derive an estimated area in kilometers which is inaccessible by a standard vehicle.

This calculation does not take into consideration that the use of a climber is not fully correlated with there being no standard vehicle access – for example, a climber may have been used due to uneven terrain (but some of the surrounding area may have been accessible by a standard vehicle), wet weather may have forced climber use, etc. This estimation also assumes that the length of each span is consistent and there have been no changes in route line length across the Regulatory Years. However, areas which require a climber for access is considered Management's best estimate of the information required based on the data available.

The estimation calculated for the 2013 Regulatory Year was reported for the 2009 to 2012 Regulatory Years. This is considered a reasonable basis for estimating these Regulatory Years as there have not been any significant changes to the network during this period.

<u>Estimated Information:</u>

Management considers the above estimates to be the best estimates of the information required based on available data.

H. Bushfire Risk (DOEF0214)

Bushfire risk is the number of Maintenance Spans in high bushfire risk areas. It has been assumed that high bushfire risk maintenance spans are equal to the number of Bushfire risk spans in the Vegetation Management System (determined based on information from the Country Fire Authority).

Estimated Information:

Management considers the above estimates to be the best estimates of the information required based on available data.

Table 8.3 Service area factors

The route line length is the aggregated length in kilometers of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag.

Preparation Methodology:

For the 2013 Regulatory Year, line length data was extracted from the Asset Management System. The route lengths for overhead and underground were summed to calculate the route line length.

Estimated Information:

Route line lengths prior to 2013 were estimated based on historical circuit length data. The estimation was derived by calculating the ratio of route line length to circuit length for the 2013 Regulatory Year. This ratio was applied to the 2006 to 2012 Regulatory Years to estimate the route line length information. Estimation is required because route line length data have not been previously recorded or reported. It is not possible to generate historic information on route line lengths from existing source systems.

Table 8.4 Weather stations

Weather station data (including the weather station number, post code, suburb/locality) has been provided for all weather stations in SPI Electricity's service area.

Preparation Methodology:

Data was extracted from the Bureau of Meteorology website. Where data from a weather station is considered relevant to the management of the network (as at 31 December 2013), the weather station has been identified as material. For the management of the network, each Network Component is allocated to the closest Weather Station that has sufficient data. SPI Electricity considers it obtains sufficient data from the material weather stations to manage the network component, as such all other weather stations have been identified as not material.