Energex

Reset RIN
Basis of Preparation
Preliminary Overview

October 2014

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Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the fast growing region of South East Queensland. Energex provides distribution services to almost 1.4 million connections, delivering electricity to 2.8 million residents and businesses across the region.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Section 1 – Preliminary Overview

1 Reset RIN Basis of Preparation - Introduction

Section 3 of Appendix E: Principles and Requirements in the Reset RIN requires that Energex must prepare a document or documents explaining its basis of preparation (basis of preparation document(s)).

The basis of preparation document(s) must be a separate document (or documents) that Energex submits with its completed regulatory templates and must follow a logical structure that enables auditors, assurance practitioners and the AER to clearly understand how Energex has complied with the requirements of this Notice.

1.1 Consistency with Reset RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 1.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must explain, for all historical information in the *regulatory templates* (up to and including 2013-14 and including *Actual Information* and *Estimated Information*) and forecast information where this has been explicitly stated in this Notice, the basis upon which Energex prepared information to populate the input cells (*basis of preparation*).	Energex has provided, for all templates containing historical information, a related Basis of Preparation document detailing the basis upon which the information has been prepared.
Energex must prepare a document or documents explaining its basis of preparation (*basis of preparation document(s)*). The basis of preparation document(s) must be a separate document (or documents) that Energex submits with its completed *regulatory templates*.	The consolidated Basis of Preparation documentation represents Energex's compliance with this requirement.
The *basis of preparation document(s)* must follow a logical structure that enables auditors, assurance practitioners and the AER to clearly understand how Energex has complied with the requirements of this *Notice*.	Each Chapter of Energex's Basis of Preparation document represents a specified regulatory template and/or table within a specified regulatory template and follows a streamlined and consistent structure compliant with this requirement.
At a minimum, the *basis of preparation document(s)* must: (a) demonstrate how the information provided is consistent	Each chapter within the Basis of Preparation complies with this

Requirements (instructions and definitions)	Consistency with requirements
with the requirements of the Notice; (b) explain the source from which Energex obtained the information provided; (c) explain the methodology Energex used to provide the required information, including any assumptions Energex made; and (d) explain circumstances where Energex cannot provide input for a variable using actual information, and therefore must provide estimated information, by explaining: i. why an estimate was required, including why it was not possible for Energex to provide *actual information*; ii. the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is Energex's best estimate, given the information sought in the *Notice*.	requirement.
Energex may provide additional detail beyond the minimum requirements if Energex considers it may assist a user to gain an understanding of the information presented in the *regulatory templates*.	Where deemed necessary, Energex has supplied additional detail through content included in the relevant Chapter and/or the inclusion of appendices.
Actual Information Information presented in response to the Notice whose presentation is materially dependent on information recorded in Energex's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice. 'Accounting records' include trial balances, the general ledger, subsidiary accounting ledgers, journal entries and documentation to support journal entries. Actual financial information may include accounting estimates, such as accruals and provisions, and any adjustments made to the accounting records to populate Energex's regulatory accounts and responses to the Notice. 'Records used in the normal course of business', for the purposes of non-financial information, includes asset registers, geographical information systems, outage analysis systems, and so on.	Where Energex has reported information as *actual information*, this has been done in compliance with this definition.
Estimated Information	Where Energex has reported

Requirements (instructions and definitions)	Consistency with requirements
Information presented in response to the Notice whose presentation is not materially dependent on information recorded in Energex's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is contingent on judgments and assumptions for which there are valid alternatives, which could lead to a materially different presentation in the response to the Notice.	information as *estimated information*, this has been done in compliance with this definition.
Forecast Information Information for Regulatory Years in the Forthcoming Regulatory Control Period and any subsequent Regulatory Years, which is forecast by Energex. Forecast Information is not subject to audit or review. Information for the final year of the Current Regulatory Control Period, 2014-15, is also forecast in nature.	Where Energex has reported information as *forecast information*, this has been done in compliance with this definition. References to forecast information within this Basis of Preparation are limited and only included where Energex deemed necessary.

1.2 Methodology

1.2.1 Assumptions

- Historical information that was required to be backcast in order to comply with the AER's guidelines as specified in Appendix E of the Reset Regulatory Information Notice (Notice) is considered estimated.
- Energex has deemed this information to be estimated information given that variations to historical information to account for Classification of Services and/or Cost Allocation Methodology changes for the forthcoming regulatory control period are:
  - not materially dependent on information in Energex's historical accounting records;
  - inherently based on judgements and assumptions for which there could be valid alternatives.

1.3 Explanatory notes

- Certain historical information in the regulatory reporting statements have been adjusted from the presentation in the category analysis regulatory reporting statements to conform to the current presentation and methodology. Where historical information has been adjusted, the rationale for the change is outlined in the respective chapter within this Basis of Preparation.

2 BoP 0.1 – Backcasting

The AER requires Energex to provide information relating to the *Previous Regulatory Control Period*, the *Current Regulatory Control Period* and for *Forecast Information* in accordance with Energex's *Applicable Cost Allocation Method* (CAM) and Classification of Services (CoS). However this requirement does not relate to the value of Energex's regulatory asset base prior to 1 July 2015.

The backcasting of information in accordance with the new CAM and CoS affects:

- **Template 2.1 – Expenditure Summary**
- **Template 2.10 – Overheads (covered separately in the Basis of Preparation for 2.10 Overheads)**
- **Template 2.11 – Labour (covered separately in the Basis of Preparation for 2.11 Labour)**
- **Template 2.12 – Input Tables**
- **Template 4.3 – Fee-based Services**
- **Template 4.4 – Quoted Services**

All backcast information is considered to be estimated information.

2.1 Consistency with Reset RIN Requirements

Table 2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 2.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Appendix E section 1.1 of the Reset RIN states that Energex must, for the *Previous Regulatory Control Period,* the *Current Regulatory Control Period* and for *Forecast Information*, allocate costs in accordance with Energex's *Applicable Cost Allocation Method*. Section 1.1(a) notes that section 1.1 does not relate to the value of Energex's regulatory asset base prior to 1 July 2015.	Energex has backcast information in accordance with the new CAM applicable from 1 July 2015.
Appendix E section 1.2 of the Reset RIN states that Energex must apply the classification of services in the framework and approach paper for the *Previous Regulatory Control Period,* the *Current Regulatory Control Period* and for *Forecast Information.* Section 1.2(a) notes this section 1.1 *[sic]* does not relate to the value of Energex's regulatory asset base prior to 1 July 2015.	Energex has backcast information in accordance with the new CoS applicable from 1 July 2015

Requirements (instructions and definitions)	**Consistency with requirements**
Previous Regulatory Control Period means the period which commenced on 1 July 2005 and ended on 30 June 2010. *Current Regulatory Control Period* means the regulatory control period which commenced on 1 July 2010 and ends on 30 June 2015. *Forecast Information* means information for Regulatory Years in the *Forthcoming Regulatory Control Period* and any subsequent Regulatory Years, which is forecast by Energex. Forecast Information is not subject to audit or review. Information for the final year of the *Current Regulatory Control Period*, 2014-15, is also forecast in nature. *Applicable Cost Allocation Method* means the cost allocation method as defined in the national electricity rules approved by the AER that will be in effect from the start of the Forthcoming Regulatory Control Period. *Forthcoming Regulatory Control Period* means the regulatory control period commencing on 1 July 2015 and ending on 30 June 2020.	Energex has backcast historical information from 1 July 2005 to 30 June 2014 where applicable. Forecast information has been provided from 1 July 2014 to 30 June 2020 under the new CAM and CoS.
Appendix E section 1.10 of the Reset RIN states that Energex must provide reconciliation between total capital and operating expenditure provided in the *regulatory templates* to the capital and operating expenditure recorded in Energex's *Regulatory Accounting Statements* and *Audited Statutory Accounts.*	Appendix 1 – Reconciling Items contains a reconciliation of total capex and opex for SCS and ACS, from the regulatory templates to the Regulatory Accounting Statements to the Audited Statutory Accounts.
Regulatory templates means worksheets contained within the Microsoft Excel workbooks at Appendix A to this *Notice.* *Regulatory Accounting Statements* means the financial reports revealing the performance and financial situation of Energex. They show the originating statutory account amount, its translation into a regulatory account amount and its disaggregation between the different categories of *distribution* services that it provides. *Audited Statutory Accounts* means the audited set of accounts prepared in accordance with Australian Securities and Investments Commission (ASIC) requirements	Energex has applied these definitions consistently.
Appendix E section 1.11 of the Reset RIN states that where any method of allocation under paragraph 1.1 changes through time, this must be reported and the quantum of the change to total capex and opex allocations between the category of distribution services must be indicated in the *basis*	In Appendix 1 – Reconciling Items, Energex has separately reported reconciling items relating to CAM changes and CoS changes.

Requirements (instructions and definitions)	Consistency with requirements
of preparation document.	
Appendix E section 1.12 of the Reset RIN states that, unless stated otherwise, capex and associated data (such as asset volumes) reported in the *regulatory templates* 2.2 to 2.12 and 4.1 must be reported against the *Regulatory Year* on an as-incurred basis.	All capex and associated data (such as asset volumes) has been reported on an as-incurred basis unless stated otherwise.
Appendix E section 1.13 of the Reset RIN states that, subject to exceptions in the case of non-network expenditures (see paragraph 10.1), expenditures reported in *regulatory templates* 2.2 to 2.9 must be *Direct Costs* only, and exclude expenditures on *Overheads.*	Expenditure reported in Templates 2.2 to 2.9 contain Direct Costs only, subject to the exceptions for Template 2.6 Non-Network.
Appendix E section 2.1 of the Reset RIN states that Energex must calculate the expenditure on capex and opex reported in *regulatory templates* 2.2 to 2.10 and 4.1 to 4.4 and report these amounts in the corresponding rows in *regulatory templates* 2.1.1 to 2.1.6.	The line items reported in Template 2.1 equal, or in some cases sum to, the totals reported in templates 2.2 to 2.10 and 4.1 to 4.4. In particular, templates 2.6, 2.10 and 4.1 to 4.4 don't disaggregate capex and opex, however these numbers need to be separately identified in template 2.1. Energex does not have dual function assets therefore tables 2.1.5 and 2.1.6 have no values.
Appendix E section 2.2 of the Reset RIN states that the total expenditure for the capex and opex for each service classification in *regulatory template* 2.1 must be mutually exclusive and collectively exhaustive.	Total capex and opex for each service classification reported in template 2.1 is mutually exclusive and collectively exhaustive.
Appendix E section 2.3 of the Reset RIN states that Energex must report an amount that reconciles total capex and opex with the sum of the capex and opex line items in the "balancing item" row in each *regulatory template* in *regulatory template 2.1*. For the avoidance of doubt this means that the sum of each of the capex and opex line items in each of the *regulatory templates* in *regulatory template 2.1* minus the balancing item must equal the total capex or opex line item in these *regulatory templates.* To do this the balancing item must: a) Include the amount of capex and opex reported where these expenditures have been reported more than once within regulatory templates 2.2 – 2.10, and 4.1 to 4.4;	The balancing items reported by Energex in Template 2.1 contain only items that have been reported more than once within regulatory templates 2.2 to 2.10 and 4.1 to 4.4. All capex is reported on an as-incurred basis therefore there are no balancing items for this component.

Requirements (instructions and definitions)	Consistency with requirements
and b) Account for any differences arising due to the reporting of capex on a basis other than the "as-incurred" basis.	
Appendix E section 2.4 of the Reset RIN states that Energex must provide an excel spread sheet that contains the calculation of balancing items reported in *regulatory template 2.1*. At a minimum, this spread sheet must: (a) for each instance where an expenditure item is reported more than once (i.e. double counted), identify: i. where that instance is reflected in expenditure included in the regulatory templates ii. the value of that expenditure in each regulatory template (b) identify each instance where the Notice requires Energex to report capex not on an "as-incurred" basis in regulatory templates 2.2 to 2.10 and 4.1 to 4.4 and, for the relevant expenditure item, list its corresponding value when expressed on an "as incurred" basis.	Energex has provided the calculation of balancing items reported in template 2.1 as Appendix 2 – Balancing Items and as a separate excel worksheet included in section 32.1 of Energex's Regulatory Proposal.

All backcast information is considered to be estimated information.

2.2 Sources

Table 2.2 below sets out the sources from which Energex obtained the required information:

Table 2.2: Information sources

Variable	Source
CoS changes:	
• Supply enhancement – upgrade from single to three phase	• volumes were sourced from Energex's Contact Centre using the PEACE system; costs were sourced from Energex's detailed workings for the 2015 regulatory proposal; Consumer Price Index (CPI) rates for de-escalations were sourced from the Australia Bureau of Statistics (ABS)
• Pre-connection services	• hours of work required to assess pre-connection services were sourced from Energex's Connections planning department reviewing

Variable	Source
	hours associated with specific projects and workgroups; labour rates were sourced from Energex's detailed workings for the 2015 regulatory proposal; CPI rates for de-escalations were sourced from the ABS
• Connection services (real estate developments / subdivisions)	• amounts for connection services were sourced from the EPM system for specific subdivision projects for which Energex received payment from customers
• Rearrangement of shared network assets	• CoS changes relate only to rearrangement projects for which Energex currently receives contributions from customers under the transitional arrangements and treats the corresponding expenditure as SCS capex. These services have been specifically identified on this basis using the EPM system
• Accreditation of alternative service providers	• Volumes were sourced from Energex's Quality Assurance team's internal tracking records; labour and oncost rates were sourced from Energex's detailed workings for the 2015 regulatory proposal; CPI rates for de-escalations were sourced from the ABS
• Type 6 metering capex and opex	• Specific account codes from Energex's general ledger trial balance
• Emergency recoverable work for known damage	• Specific account codes from Energex's general ledger trial balance and regulatory accounting statement supporting workpapers
• Solar PV FiT	• Specific account codes from Energex's general ledger trial balance
CAM changes	Energex's corporate modelling tool (Cognos) was used to reallocate costs in accordance with CoS and CAM changes

2.3 Methodology

CoS changes impacted services as detailed in Table 2.3: CoS Changes below:

Table 2.3: CoS Changes

Service	Current classification 2010-2015	New classification 2015-2020
Supply enhancement – upgrade from single to three phase	SCS capex	ACS opex
Pre-connection services	SCS capex	ACS opex
Connection services (real estate developments / subdivisions)	SCS capex	ACS opex
Rearrangement of shared network assets	SCS capex	ACS opex
Accreditation of alternative service provider	SCS overheads	ACS opex
Type 6 metering capex and opex	SCS capex and opex	ACS capex and opex
Emergency recoverable work for known damage	ACS opex	Non-regulated opex
Solar PV FiT	SCS opex	Jurisdictional scheme – excluded entirely

- Reclassification of services has resulted in changes to the allocation of overheads, which have been allocated consistent with Energex's new CAM.
- Backcasting for CoS and CAM resulted in changes to the Reset RIN templates as disclosed in Table 2.4: Affected Templates:

Table 2.4: Affected Templates

Service	Template
Supply enhancement – upgrade from single to three phase	2.1 – Expenditure Summary 2.10 – Overheads 2.12 – Input Tables 4.3 – Fee-based Services
Pre-connection services Connection services (real estate developments / subdivisions Rearrangement of network assets Accreditation of alternative service provider Emergency recoverable work for known damage	2.1 – Expenditure Summary 2.10 – Overheads 2.12 – Input Tables 4.4 – Quoted Services

Service	Template
Type 6 metering capex and opex	2.1 – Expenditure Summary 2.10 – Overheads 2.12 – Input Tables *(no change to other templates as metering is separately reported in template 4.2)*
Solar PV FiT	2.1 – Expenditure Summary 2.10 – Overheads 2.12 – Input Tables *(no change to other templates as Solar PV FiT was reported as part of template 2.10)*

2.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- For pre-connection services where volumes were only available back to 2010/11, the same volumes were assumed for 2008/09 and 2009/10. Costs for 2008/09 and 2009/10 were estimated based on de-escalated hourly rates using the average hours from 2010/11 to 2013/14;
- For accreditation of alternative service providers, volumes were based on the number of applications received;
- For rearrangement of network assets, volumes were based on the number of projects completed in the year;
- As material and fleet oncosts form part of Energex's direct costs, they have been treated accordingly and reclassified with the underlying direct costs where appropriate;
- Capitalised material and fleet oncosts (included in capitalised network and corporate overheads respectively) have been treated consistently with historical reporting as CoS changes would not have a material impact on results. This is because the most material CoS changes (metering capex from SCS to ACS capex and metering opex from SCS to ACS opex) have no impact on total proportions capitalised. The other significant item within CoS changes (rearrangement of network assets from SCS capex to ACS opex) is immaterial to total direct costs and therefore even less material to the components of material and fleet oncosts;
- No backcasting adjustments were made for Related Parties as:

- There are no related party costs for metering;
- Of the related party costs reported for Overheads, the vast majority related to SPARQ IT costs, which weren't affected by CoS and CAM changes

2.3.2 Approach

CoS changes

As detailed in Table 2.2: Information sources above, Energex could reclassify some services based on account codes within the general ledger (GL) trial balance (TB). For the remainder, Energex sought input from relevant areas of the business.

Energex applied the following approach to determine the numbers reported:

- For supply enhancement, pre-connection services and accreditation of alternative service providers:
  - Obtained source information from relevant areas of the business;
  - Applied unit rates to determine costs. Where these rates were derived from Energex's detailed workings for the 2015 regulatory proposal, the rates needed to be de-escalated back to nominal dollars. De-escalated applicable rates using the ABS CPI for weighted average of eight capital cities;
- Volumes were typically sourced directly from the business or project ledger. Where volumes were not available, the last volume available was used for the years when it wasn't available (eg: volumes for pre-connection services for 2008/09 and 2009/10 have been assumed to be the same as 2010/11).
- Rearrangement of assets project costs sourced from EPM were identified from the rearrangement activities in the general ledger. As Energex completed some company initiated augmentation work when completing these projects, the capital contributions were used as a proxy for the value of the customer requested asset rearrangement component. The customer contribution value was apportioned to the labour, contract, material and other cost components based on the total project proportions.
- Real-estate developments projects with an S prefix on the project (which identified subdivision projects) were identified and the value of the cash contributions was used as a proxy for the customer requested real-estate developments. The customer contribution value was apportioned to the labour, contract, material and other cost components based on the total project proportions.

For information reclassified based on GL TB information:

- Metering capex was reclassified based on the estimated proportion of the balance of the relevant account. The relevant account is currently used for service connections, which will include work for both SCS and ACS under the new CoS. A review of this expenditure was conducted in 2013/14 to determine the percentage split to low voltage meters (becoming ACS from 2015) and low voltage services (remaining SCS).

- Meter maintenance was reclassified based on the estimated proportion of the balance of the relevant account. The relevant account is currently used for customer service work, which will include work for both SCS and ACS under the new CoS. A review of this expenditure for the regulatory proposal determined the percentage of the expenditure attributable to meter maintenance, which will become ACS from 2015

- From 2015 metering opex will also include costs incurred by Energex departments responsible for Energy Data Management (including meter reading) and Meter Data Agency. Accordingly relevant costs have been reclassified from SCS to ACS opex;

- Emergency recoverable works for known damage were reclassified from ACS to unregulated opex based on:
  - the specific account code for known damage for 2008/09 and 2009/10. For these years, it was reported as part of the sub-category "Miscellaneous" within template 4.4 Quoted Services. Specific amounts and volumes were sourced from the regulatory accounting statements supporting workpapers;
  - the entire balance of the specific sub-category within template 4.4 Quoted Services from 2010/11. This equates to the specific account code for known damage, which was used for overheads backcasting
  - (Note: 2008/09 amounts were only required for template 2.12 Input Tables and not for template 4.4 Quoted Services as this template does not require disclosure of 2008/09 numbers)

- Solar PV FiT was reclassified from SCS opex based on the specific account code. It has been excluded entirely as it will be subject to a jurisdictional scheme from July 2015.

- CoS changes were applied exclusive of general overheads.

Direct costs

- Template 4.2 Metering was not affected by CoS changes as the template is specifically for metering.

(Note: while the metering reclassifications detailed above under sections 5(a)-(c) weren't required for template 4.2 Metering, they were required for template 2.10 Overheads.)

- Templates 4.3 Fee-based Services and 4.4 Quoted Services were adjusted by the amounts and volumes identified above for the services listed in Table 2.4: Affected Templates, namely:
  - Addition of supply enhancement – upgrade from single to three phase
  - Addition of pre-connection services
  - Addition of connection services (real estate developments / subdivisions)

  - Addition of rearrangement of network assets
  - Addition of accreditation of alternative service provider
  - Deduction of emergency recoverable work for known damage

Input Tables

- Information for template 2.12 Input Tables was generated at the same time as the information compiled for CoS and CAM changes. In most cases, those amounts were built up by component (ie: materials, labour, contractor or other) at the time and have been reflected in the rows for Overheads, Fee-based Services and Quoted Services as applicable.
- The exception was for sub-divisions (which is an individual service within Quoted Services, as detailed above in Table 2.4: Affected Templates) where the proportions used for the various components of direct costs were based on:
  - Proportions used for the initial years (2008/09 to 2012/13), based on 2012/13 projects
  - Actual project costs for the relevant services for 2013/14
- Adjustments for unregulated support costs were applied in the same proportions as the underlying data (ie: the materials, labour, contract and other costs for Network Overheads and Corporate Overheads before the adjustment for unregulated support costs).
- Advice received from the AER after submission of the Category Analysis RIN for the initial years indicated that the totals reported in the relevant regulatory templates needed to equal only the materials + labour + contractor + other costs in template 2.12 Input Tables, and that related party costs were additional to these components. Accordingly, the Reset RIN has been prepared on the same basis.
- As mentioned above in section 2.3.1 Assumptions, all related party costs remain unchanged for backcasting.

Expenditure Summary – reconciling items

The approach for template 2.1 Expenditure Summary is consistent with the information provided in that section of the BoP, with differences arising due to backcasting as detailed in Appendix 1 – Reconciling Items (which reconciles the regulatory templates to the regulatory accounting statements). Reset RIN and backcasting adjustments for reconciling items relate to:

- The exclusion of network and corporate overheads for ACS capex and opex. These items were previously included as reconciling items as there was no ability to report the amounts in tables 2.1.3 and 2.1.4 of the Category Analysis RIN for the initial years. These items now appear in template 2.1 so are included in the totals for the regulatory templates and are no longer required to reconcile to the amounts in the regulatory accounting statements;

- Separate amounts for backcasting adjustments. Energex has separately identified these as:
  - Backcasting adjustments – Overheads template – these reflect CoS and CAM adjustments to template 2.10 Overheads
  - Backcasting adjustments – Fee-based & Quoted templates – these reflect CoS adjustments to direct costs in templates 4.3 Fee-based Services and 4.4 Quoted Services

2.4 Estimated Information

All backcast information is considered to be estimated.

2.4.1.1 Justification for estimates

Estimated information is defined in the Reset RIN as:

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

Accordingly, backcast information for CoS and CAM changes must meet this definition as it is:

- not materially dependent on information in Energex's historical accounting records;
- inherently based on judgements and assumptions for which there could be valid alternatives.

In addition, sections 3.6 and 3.7 of Appendix C: Audit and Review to the Reset RIN indicates that backcast information is subject to review consistent with that required for estimated information.

2.4.1.2 Basis for estimates

- The basis for backcasting estimates is detailed above in sections 2.2 Sources and 2.3 Methodology.
- These reflect the best estimates as they reflect Energex's interpretations of CoS changes and are the only source of information available.

2.5 Explanatory notes

- Backcasting adjustments disclosed in templates 4.3 Fee-based Services and 4.4 Quoted Services are typically reflected as new line items. Exceptions relate to:

- Emergency recoverable work for known damage – this service has been reclassified from ACS to unregulated. From 2010/11, where the balance was reported against its own line item in template 4.4, the Reset RIN templates have been restated to 0. Prior to 2010/11, this service was reported as part of the line item for Miscellaneous, therefore the reclassification is reflected as a reduction of this line item

- Rearrangement of shared network assets – under Queensland transitional arrangements, these services were previously treated as SCS capex with a capital contribution for the customer-funded portion. This reclassification has been added to the existing line item for Rearrangement of assets within template 4.4. One project in particular contributed to the increase, with approximately $47M reclassified over the four years from 2008/09 to 2011/12 (with $24.4M in 2009/10)

- While backcasting for Metering primarily affected template 2.1 Expenditure Summary, there has also been an adjustment made to template 4.2 Metering to remove SCS capex. This is because Appendix E section 19 of the Reset RIN no longer requires Energex to distinguish expenditure for metering services between SCS and ACS and instead implies that all expenditure should be ACS only. Accordingly, Energex has removed Other Metering capex from the historical information in the Reset RIN, as it relates to SCS capex for current transformers and load control relays.

Appendix 1 – Reconciling Items

RECONCILIATION FROM REGULATORY TEMPLATES TO REGULATORY ACCOUNTING NUMBERS TO AUDITED STATUTORY ACCOUNTS	2009			2010			2011			2012			2013			2014		
	CAPEX $M	OPEX $M	TOTAL $M	CAPEX $M	OPEX $M	TOTAL $M	CAPEX $M	OPEX $M	TOTAL $M	CAPEX $M	OPEX $M	TOTAL $M	CAPEX $M	OPEX $M	TOTAL $M	CAPEX $M	OPEX $M	TOTAL $M
Template 2.1 Summary Numbers																		
SCS	759.4	303.5	1,063.0	887.4	307.0	1,194.3	855.0	341.0	1,195.9	842.7	373.2	1,215.8	800.9	398.5	1,199.4	683.9	368.8	1,052.7
ACS	44.3	75.9	120.3	40.3	110.7	150.9	49.5	83.1	132.6	63.1	84.6	147.7	61.2	79.8	141.0	51.1	87.5	138.6
TOTAL from Template 2.1	803.7	379.5	1,183.2	927.6	417.6	1,345.3	904.5	424.1	1,328.6	905.8	457.8	1,363.5	862.1	478.3	1,340.5	735.0	456.2	1,191.2
Adjusted for:																		
• Replacement expenditure not included in Template 2.2 Repex as there was no basis on which to allocate expenditure to categories, but is included in the regulatory accounting numbers	7.1	-	7.1	3.2	-	3.2	15.4	-	15.4	9.1	-	9.1	12.7	0	12.7	15.1	0	15.1
• Augmentation expenditure not included in Template 2.3 Augex as there was no basis on which to allocate expenditure to categories, but is included in the regulatory accounting numbers	6.3	-	6.3	4.0	-	4.0	4.0	-	4.0	2.8	-	2.8	- 6.3	0	- 6.3	- 0.0	0	- 0.0
• Demand Side Management expenditure excluded from Template 2.3 Augex but included in the regulatory accounting numbers	0.7	-	0.7	2.2	-	2.2	2.3	-	2.3	- 0.2	-	- 0.2	2.3	0	2.3	1.3	0	1.3
• Relocation of assets excluded from Templates 2.3 Augex & 2.5 Connections in accordance with the definition of "connections expenditure" but included in the regulatory accounting numbers	18.1	-	18.1	43.3	-	43.3	23.9	-	23.9	22.1	-	22.1	19.1	0	19.1	12.2	0	12.2
• Gifted assets excluded from Templates 2.5 Connections but included in the regulatory accounting numbers	13.7	-	13.7	15.3	-	15.3	21.1	-	21.1	24.2	-	24.2	23.3	0	23.3	25.2	0	25.2
• Asset replacements excluded from Template 2.8 Maintenance in accordance with the definition of "non-routine maintenance" that are included in the regulatory accounting numbers	-	3.8	3.8	-	0.3	0.3	-	0.2	0.2	-	0.2	0.2	-	0.20	0.2	-	0.32	0.3
• Gifted assets excluded from Templates 4.1 Public Lighting but included in the regulatory accounting numbers	5.1	-	5.1	3.4	-	3.4	4.3	-	4.3	6.3	-	6.3	7.8	0	7.8	6.0	0	6.0
• Asset reconfiguration excluded from Template 4.1 Public Lighting as it doesn't meet the definition of "Public Lighting Services" that are included in the regulatory accounting numbers	3.2	-	3.2	4.0	-	4.0	3.4	-	3.4	3.3	-	3.3	2.1	0	2.1	2.4	0	2.4
• Inventory items included in Template 4.2 Metering that are excluded from the regulatory accounting numbers for capex and opex	- 6.7	-	- 6.7	- 6.3	-	- 6.3	- 10.4	-	- 10.4	- 9.9	-	- 9.9	- 8.1	0	- 8.1	- 6.9	0	- 6.9
• Adjustments made for the regulatory accounting numbers that don't appear in the source information for the relevant regulatory templates	1.8	- 3.9	- 2.1	- 11.7	0.9	- 10.8	- 7.9	- 0.1	- 8.0	- 4.5	2.0	- 2.5	- 8.1	- 0.6	- 8.7	- 5.3	2.0	- 3.3
• Backcasting adjustments - Overheads template	- 16.7	- 21.9	- 38.6	14.7	- 34.2	- 19.5	20.5	- 10.9	9.6	32.1	40.8	72.9	25.2	142.8	168.0	10.0	207.3	217.3
• Backcasting adjustments - Fee-based & Quoted templates	-	- 14.5	- 14.5	-	- 30.7	- 30.7	-	- 9.1	- 9.1	-	- 14.4	- 14.4	-	-12.3	- 12.3	-	-10.7	- 10.7
Regulatory Accounting Statements	836.3	342.9	1,179.3	999.8	353.9	1,353.7	981.0	404.2	1,385.2	990.9	486.3	1,477.2	932.1	608.4	1,540.5	794.9	655.2	1,450.1
Adjusted for:																		
• TUOS	-	246.6	246.6	-	286.0	286.0	-	343.8	343.8	-	390.0	390.0	-	394.3	394.3	-	404.2	404.2
• Finance costs	-	212.5	212.5	-	224.7	224.7	-	305.4	305.4	-	321.4	321.4	-	358.4	358.4	-	395.2	395.2
• Depreciation, amortisation & impairment	-	235.4	235.4	-	242.5	242.5	-	286.3	286.3	-	329.5	329.5	-	352.6	352.6	-	385.4	385.4
• Non-regulated services	11.4	123.1	134.5	- 1.8	100.3	98.5	5.0	65.0	70.1	5.0	74.6	79.6	4.7	55.9	60.6	34.7	32.2	39.9
• Capitalised depreciation	23.3	-	23.3	28.4	-	28.4	-	-	-	-	-	-	-	-	-	-	-	-
Audited Statutory Accounts - Consolidated	871.0	1,160.5	2,031.5	1,026.4	1,207.4	2,233.8	986.0	1,404.7	2,390.8	995.9	1,601.8	2,597.8	936.8	1,769.5	2,706.4	829.6	1,872.3	2,674.8

Appendix 2 – Balancing Items

Table 2.1.1 - Standard control services capex

Balancing item is made up of:	Actual ($000s nominal)					
	2009	2010	2011	2012	2013	2014
Material oncosts - captured as part of direct capex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Network Overhead - POW Material Management			-7,391.7	-8,507.8	-8,490.2	-8,030.4
Fleet oncosts - captured as part of direct capex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Corporate Overhead - Fleet			-12,902.4	-14,576.2	-12,208.6	-12,382.9
Total balancing item per above	**0.0**	**0.0**	**-20,294.1**	**-23,084.0**	**-20,698.8**	**-20,413.3**

Table 2.1.2 - Standard control services opex by category

Balancing item is made up of:	Actual ($000s nominal)					
	2009	2010	2011	2012	2013	2014
Material oncosts - captured as part of direct opex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Network Overhead - POW Material Management			-229.0	-304.3	-515.4	-532.7
Fleet oncosts - captured as part of direct capex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Corporate Overhead - Fleet			-6,288.0	-5,951.6	-6,552.3	-6,462.4
Non-network costs - included in Template 2.6 Non-network as opex and Template 2.10 Overheads	-117,655.6	-129,557.5	-154,621.8	-172,018.0	-181,560.7	-187,570.1
Total balancing item per above	**-117,655.6**	**-129,557.5**	**-161,138.9**	**-178,273.9**	**-188,628.4**	**-194,565.3**

Table 2.1.3 - Alternative control services capex

Balancing item is made up of:	Actual ($000s nominal)					
	2009	2010	2011	2012	2013	2014
Material oncosts - captured as part of direct opex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Network Overhead - POW Material Management			-54.8	-228.2	-279.8	-134.8
Fleet oncosts - captured as part of direct capex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Corporate Overhead - Fleet			-128.9	-276.9	-230.9	-194.1
Large Customer Connections reported in 2.5 Connections and 4.4 Quoted Services			-734.1	-6,000.4	-6,728.6	-3,252.4
Metering double counted in 4.2 Metering as New Installations and Meter Replacements	-5,649.1	-5,021.1	-4,164.4	-3,576.0	-3,609.3	-4,183.8
Total balancing item per above	**-5,649.1**	**-5,021.1**	**-5,082.2**	**-10,081.5**	**-10,848.6**	**-7,765.0**

Table 2.1.4 - Alternative control services opex

Balancing item is made up of:	Actual ($000s nominal)					
	2009	2010	2011	2012	2013	2009
Material oncosts - captured as part of direct opex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Network Overhead - POW Material Management			-239.4	-154.3	-94.4	-246.2
Fleet oncosts - captured as part of direct capex (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in Template 2.10 Overhead as Corporate Overhead - Fleet			-952.5	-908.1	-480.2	-779.7
Metering opex - reported in Template 4.1 Metering and certain items (Meter Test, Schedulled Meter Reads and Meter Maintenance) also reported in 2.10 Overheads	-6,135.6	-7,255.0	-6,348.4	-7,448.2	-7,679.2	-7,963.7
Metering opex - reported in Template 4.1 Metering and certain items (Meter Investigation and Special Meter Reads) also reported in 4.3 Fee-Based Services	-4,659.7	-5,365.3	-4,901.9	-5,034.5	-4,835.2	-4,560.2
Total balancing item per above	**-10,795.3**	**-12,620.2**	**-12,442.2**	**-13,545.1**	**-13,089.0**	**-13,549.6**

Energex

Reset RIN
Basis of Preparation
2. Expenditure

October 2014

positive energy

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the fast growing region of South East Queensland. Energex provides distribution services to almost 1.4 million connections, delivering electricity to 2.8 million residents and businesses across the region.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Energex
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Section 2 – Expenditure

1 BoP 2.1.1 – Expenditure Summary & Reconciliation

The AER requires Energex to provide the following categories relating to table 2.1.1 Standard control services capex:

- Replacement expenditure
- Connections
- Augmentation expenditure
- Non-network
- Capitalised network overheads
- Capitalised corporate overheads
- Metering
- Public lighting
- Balancing item
- TOTAL GROSS CAPEX (includes capcons)
- Capcons

The AER requires Energex to provide the following categories relating to table 2.1.2 Standard control services opex:

- Vegetation management
- Maintenance
- Emergency response
- Non-network
- Network overheads
- Corporate overheads
- Metering
- Public lighting
- Balancing item
- TOTAL OPEX

The AER requires Energex to provide the following categories relating to table 2.1.3 Alternative control services capex:

- Connections
- Capitalised network overheads
- Capitalised corporate overheads
- Metering
- Public lighting
- Balancing item
- TOTAL CAPEX

The AER requires Energex to provide the following categories relating to table 2.1.4 Alternative control services opex:

- Connections
- Network overheads
- Corporate overheads
- Metering

- **Public lighting**
- **Fee and quoted**
- **Balancing item**
- **TOTAL OPEX**

The AER requires Energex to provide the following categories relating to table 2.1.5 Dual function assets capex:

- **Replacement expenditure**
- **Connections**
- **Augmentation expenditure**
- **Non-network**
- **Capitalised network overheads**
- **Balancing item**
- **TOTAL GROSS CAPEX (includes Capcons)**
- **Capcons**

The AER requires Energex to provide the following categories relating to table 2.1.6 Dual function assets opex:

- **Vegetation management**
- **Maintenance**
- **Emergency response**
- **Non-network**
- **Network overheads**
- **Corporate overheads**
- **Balancing item**
- **TOTAL OPEX**

Refer to the Basis of Preparation for each individual template for the components that are Actual and Estimated.

All balancing and reconciling items are Estimated information.

These variables are part of Regulatory Template - 2.1 Expenditure Summary.

1.1 Consistency with Reset RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 1.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Appendix E section 1.10 of the Reset RIN states that Energex must provide reconciliation between total capital and operating expenditure provided in the *regulatory templates* to the capital and operating expenditure recorded in Energex's *Regulatory Accounting Statements* and *Audited Statutory Accounts.*	Appendix 1 to BoP 0.1 - Backcasting contains a reconciliation of total capex and opex for SCS and ACS, from the regulatory templates to the

Requirements (instructions and definitions)	Consistency with requirements
	Regulatory Accounting Statements to the Audited Statutory Accounts.
Appendix E section 1.12 of the Reset RIN states that, unless stated otherwise, capex and associated data (such as asset volumes) reported in the regulatory templates 2.2 to 2.12 and 4.1 must be reported against the Regulatory Year on an as-incurred basis.	All capex and associated data (such as asset volumes) has been reported on an as-incurred basis unless stated otherwise.
Appendix E section 1.13 of the Reset RIN states that, subject to exceptions in the case of non-network expenditures (see paragraph 10.1), expenditures reported in *regulatory templates* 2.2 to 2.9 must be *Direct Costs* only, and exclude expenditures on *Overheads.*	Expenditure reported in Templates 2.2 to 2.9 contain Direct Costs only, subject to the exceptions for Template 2.6 Non-Network.
Appendix E section 2.1 of the Reset RIN states that Energex must calculate the expenditure on capex and opex reported in *regulatory templates* 2.2 to 2.10 and 4.1 to 4.4 and report these amounts in the corresponding rows in *regulatory templates* 2.1.1 to 2.1.6.	The line items reported in Template 2.1 equal, or in some cases sum to, the totals reported in templates 2.2 to 2.10 and 4.1 to 4.4. In particular, templates 2.6, 2.10 and 4.1 to 4.4 don't disaggregate capex and opex, however these numbers need to be separately identified in template 2.1. Energex does not have dual function assets therefore tables 2.1.5 and 2.1.6 have no values.
Appendix E section 2.2 of the Reset RIN states that the total expenditure for the capex and opex for each service classification in *regulatory template* 2.1 must be mutually exclusive and collectively exhaustive.	Total capex and opex for each service classification reported in template 2.1 is mutually exclusive and collectively exhaustive.
Appendix E section 2.3 of the Reset RIN states that Energex must report an amount that reconciles total capex and opex with the sum of the capex and opex line items in the "balancing item" row in each *regulatory template* in *regulatory template 2.1*. For the avoidance of doubt this means that the sum of each of the capex and opex line items in each of the *regulatory templates* in *regulatory template 2.1* minus the balancing item must equal the total capex or opex line item in these *regulatory templates.* To do this the balancing item must: (a) Include the amount of capex and opex reported where	The balancing items reported by Energex in Template 2.1 contain only items that have been reported more than once within regulatory templates 2.2 to 2.10 and 4.1 to 4.4. All capex is reported on an as-incurred basis therefore there are no balancing items for this component.

Requirements (instructions and definitions)	Consistency with requirements
these expenditures have been reported more than once within regulatory templates 2.2 – 2.10, and 4.1 to 4.4; and (b) Account for any differences arising due to the reporting of capex on a basis other than the “as-incurred” basis.	
Appendix E section 2.4 of the Reset RIN states that Energex must provide an excel spread sheet that contains the calculation of balancing items reported in regulatory template 2.1. At a minimum, this spread sheet must: (a) for each instance where an expenditure item is reported more than once (i.e. double counted), identify: i. where that instance is reflected in expenditure included in the regulatory templates ii. the value of that expenditure in each regulatory template identify each instance where the Notice requires Energex to report capex not on an “as-incurred” basis in regulatory templates 2.2 to 2.10 and 4.1 to 4.4 and, for the relevant expenditure item, list its corresponding value when expressed on an “as incurred” basis.	Energex has provided the calculation of balancing items reported in template 2.1 as Appendix 2 to BoP 0.1 – Backcasting. A separate supporting Excel workbook is also included in Section 32.1 of Energex’s Regulatory Proposal – RIN Supporting documents.

1.2 Sources

- Summary numbers in template 2.1 were sourced from the relevant regulatory templates. Details of specific sources can be found in the relevant Basis of Preparation.
- Balancing items in template 2.1 were sourced from a review of individual templates to identify items reported more than once.
- Reconciling items were sourced from a review of each year’s regulatory accounting statements and/or supporting workpapers (regulatory accounting numbers), combined with the detailed workings for each relevant regulatory template. Appendix 1 to this BoP contains mapping of the Reset RIN capex categories to the Annual Performance RIN categories.
- In addition, reconciling items have been included resulting from backcasting requirements (refer to the BoP for backcasting).

The statutory to regulatory reconciliation is provided in Appendix 1 of BoP 0.1 – Backcasting and reconciles:

- Capex from the regulatory accounting statements to additions to Work in Progress from the audited statutory accounts; and
- Opex from the regulatory accounting statements to total expenses from the audited statutory accounts.

1.3 Methodology

- Summary numbers are direct costs only, which are calculated as total costs less general overheads.
- General overheads are calculated in accordance with the approved Cost Allocation Method applicable for 2014.
- Summary numbers from the individual templates are not considered hereafter in this Basis of Preparation and further details can be found in the relevant Basis of Preparation for the individual templates.

The methodology for calculating balancing and reconciling items is detailed below in section 1.3.2 - Approach.

1.3.1 Assumptions

No specific assumptions are made in relation to this template.

1.3.2 Approach

Balancing items

Balancing items have been calculated for amounts that appear more than once in the summary numbers, as detailed below. The calculations are detailed in in Appendix 2 of BoP 0.1 – Backcasting.

- Fleet oncosts – captured as part of the direct capex and opex amounts for SCS and ACS (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and also captured in:
  - Template 2.6 Non-network as Motor Vehicles opex and Other Fleet Tools & Equipment opex; and
  - Template 2.10 Overhead as Corporate Overhead – Fleet.
- Materials oncosts – captured as part of the direct capex and opex numbers for SCS and ACS (as they are directly attributable in accordance with the AER-approved Cost Allocation Method) and captured in Template 2.10 Overhead as Network Overhead – POW Material Management.
- Property opex – captured in:
  - Template 2.6 Non-network as Buildings & Property opex; and

- Template 2.10 Overhead as Corporate Overhead – Property.

- IT & Communications opex– captured in:
  - Template 2.6 Non-network IT & Communications opex; and
  - Template 2.10 Overhead as Corporate Overhead – IT and Communications.

- Metering – the various line items within Template 4.2 Metering are duplicated as follows:
  - Meter Test – also captured in Template 2.10 Overheads as Network Overheads – Customer Service;
  - Meter Investigation – also captured in Template 4.3 Fee-Based Services as a Meter Test and Meter Inspection;
  - Scheduled Meter Reading – also captured in Template 2.10 Overheads as Network Overheads – Customer Services;
  - Special Meter Reading – also captured in Template 4.3 Fee-Based Services as Off-cycle Meter Reads; and
  - Meter Maintenance – also captured in Template 2.10 Overheads as Network Overheads – Customer Service.

- There is no duplication of Public Lighting capex as the numbers reported in Template 2.2 Repex and Template 4.1 Public Lighting are for different expenditure items (refer to Basis of Preparation 4.1.3 Public Lighting – Cost Metrics for more information).

Reconciling items

Where the summary numbers do not equal the regulatory accounting numbers, differences are detailed in the reconciliation included in Appendix 1 of BoP 0.1 – Backcasting. These reconciling items typically relate to:

- Expenditure not included in the relevant regulatory templates as there was no basis on which to allocate a portion of expenditure to categories, but is included in the regulatory accounting numbers.

- Items which are excluded from (or included in) the relevant regulatory templates in accordance with the definitions, but are included in (or excluded from) the regulatory accounting numbers.

- Gifted assets which are excluded from the relevant regulatory templates in accordance with the relevant definitions but are included in the regulatory accounting numbers.

- Adjustments made for the regulatory accounting numbers that don't appear in the source information for the relevant regulatory templates. These are typically for:
  - accruals entries not processed to the individual projects until the actual expenditure is recorded

– entries identified after balance date

- Network Overheads and Corporate Overheads for ACS, which are not included in Template 2.1 but are included in the regulatory accounting numbers.

Energex's approach to obtaining the regulatory accounting numbers is detailed in Table 1.2 below:

Table 1.2: Approach to obtaining regulatory accounting numbers

Table 2.1.1 - Standard control services capex	
	Actual ($000s nominal)
	2014
Replacement expenditure	As per the AER CA RIN requirements (page 53, CA explanatory statements), repex includes Control Centre - SCADA which was reported in non-system assets in the annual regulatory accounts.
Replacement expenditure	Directly from the annual regulatory accounts.
Connections	
Augmentation Expenditure	
Non-network	Annual regulatory accounts and/or supporting workings. Control Centre - SCADA direct costs are included in repex and excluded from Non-network as per the AER CA RIN requirements.
capitalised network overheads	Annual regulatory accounts and/or supporting workings
capitalised corporate overheads	Annual regulatory accounts and/or supporting workings
balancing item	Refer to the separate reconciliation sheet
TOTAL GROSS CAPEX (includes capcons)	Annual regulatory accounts
capcons	Annual regulatory accounts

Table 2.1.2 - Standard control services opex by category	
	Actual ($000s nominal)
	2014
Vegetation management	Directly from the annual regulatory accounts
Maintenance	Directly from the annual regulatory accounts; includes Inspection and Planned Maintenance. Breakdown into Inspection and Planned Maintenance is obtained from the data supporting the annual regulatory accounts
Emergency response	Directly from the annual regulatory accounts; includes Corrective Repair and Emergency Response from the annual regulatory
Non-network	Sum of opex totals from table 2.6 Non-network as non-network opex summary numbers are not available from the annual regulatory accounts
network overheads	Annual regulatory accounts and/or supporting workings
corporate overheads	Annual regulatory accounts and/or supporting workings
balancing item	Refer to the separate reconciliation sheet
TOTAL OPEX	

Table 2.1.3 - Alternative control services capex	
	Actual ($000s nominal)
	2014
Connections	Energex does not have ACS Connections Assets
Metering	Energex does not have ACS Metering Assets
Public lighting	Directly from reg accounts
Fee and quoted	
balancing item	Refer to the separate reconciliation sheet
TOTAL CAPEX	

Table 2.1.4 - Alternative control services opex	
	Actual ($000s nominal)
	2014
Connections	Energex has no Alternative Control Services connections and metering opex.
Metering	
Public lighting	Direct from reg accounts
Fee and quoted	
balancing item	Refer to the separate reconciliation sheet
TOTAL OPEX	Annual regulatory accounts

1.4 Estimated Information

- Summary numbers reported in template 2.1 have been treated as Estimates where the relevant regulatory templates are Estimates or a combination of Actual and Estimates.

- All numbers reported as balancing or reconciling items are Estimates.

1.4.1 Justification for Estimated Information

- Balancing items are regarded as Estimates as they are calculated from the summary numbers, which are a combination of Actuals and Estimates.

- All reconciling items are regarded as Estimates as they result from comparing regulatory accounting numbers with summary numbers (which are a combination of Actuals and Estimates).

1.4.2 Basis for Estimated Information

Balancing items

The approach for calculating the balancing items is included above in section 1.3.2. These numbers are reported as Estimates as the source information is a combination of Actuals and Estimates.

1.5 Explanatory notes

- Explanations for trends in SCS capex (Table 2.1.1) are provided below for the summary numbers. These trends reflect:
  - the aging network, evidenced by a doubling of replacement expenditure over the period;
  - slow economic conditions since the Global Financial Crisis, seen in the declining Connections and customer-driven spend; and
  - significant reductions in augmentation expenditure, mostly due to reduced minimum reliability standard requirements and reductions in capex for expected peak demand.

- Explanations for trends in SCS Opex (Table 2.1.2) are provided below for the summary numbers:
  - The spike in Maintenance costs in 2012 reflects the recognition of a provision for overhead service cable inspections relating to faulty cables;
  - Emergency response shows significant increases in 2011 and 2013 due to the major storms and flooding in South-East Queensland.

- Extra explanatory notes can be found in the individual Basis of Preparation for respective templates.

- The Total in 2012/13 for total Opex doesn't add correctly in Cell H69. The RIN Template is set by the AER with the formula cells locked. Energex has identified an error with the Formula in Cell H69 of Template 2.1. This formula does not take account of the balancing item and the SCS Opex appears to be overstated. The AER has been made aware of this error.

1.6 Accounting policies

The Group changed its accounting policy in 2014 with respect to the basis for determining the cost related to its defined benefit fund.

Nature of the change

- The change is as a result of revisions to Accounting Standard AASB 119 Employee Benefits. The interest income component of return on plan assets is still reflected in profit and loss, whilst all other related plan asset income (for example, dividends, other income) is now reflected directly in other comprehensive income.
- The interest income component now forms part of net interest expense (income) that is calculated based on the net defined benefit liability (asset) by applying the discount rate used to discount the defined benefit obligation at the beginning of the annual period.

Impact of the change

- The impact of the change in AASB 119 is reflected in increase in employee benefits expense of $11M and subsequent increase to all Opex and Capex categories through overhead allocations.

2 BoP 2.2.1 – Repex – Expenditure

In relation to RIN Table 2.2.1, the AER requires Energex to provide actual expenditure values and replacement volumes for each year between 2008-09 and 2013-14 for the following asset groups:

- **Poles, disaggregated by highest operating voltage and material type**
- **Pole top structures, disaggregated by highest operating voltage**
- **Overhead conductors, disaggregated by highest operating voltage and number of phases**
- **Underground cables, disaggregated by highest operating voltage**
- **Service lines, disaggregated by, connection voltage, customer type and connection complexity**
- **Transformers, disaggregated by mounting type, highest operating voltage, ampere rating and number of phases**
- **Switchgear, disaggregated by highest operating voltage and switch function**
- **Public lighting, disaggregated by asset type and lighting obligation**
- **SCADA, network control and protections systems, disaggregated by function**
- **Other, DNSP defined**

Estimated Information is provided for all figures.

These variables are a part of Regulatory Template 2.2 – Repex.

Note that the Basis of Preparation for asset failure volumes is provided in a separate Basis of Preparation.

2.1 Consistency with Reset RIN Requirements

Table 2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 2.1 – Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Where Energex provides asset sub-categories corresponding to the prescribed asset categories in Table 2.2.1, Energex must ensure that the expenditure and asset replacement / asset failure volumes of these sub-categories reconcile to the higher level asset category. Energex is required to insert additional rows and provide a clear indication of the asset category applicable to each sub-category.	Not applicable as asset sub-categories have not been provided
In instances where Energex is reporting expenditure associated with asset refurbishments/ life extensions capex it must insert additional rows at the bottom of the table for the relevant asset group to account for this. Energex must provide the required data, applying the corresponding asset category name followed by the word “REFURBISHED”.	Demonstrated in section 2.5 - Explanatory notes

Requirements (instructions and definitions)	Consistency with requirements
In instances where Energex considers that both the prescribed asset group categories and the sub-categorisation provisions set out in (a) do not account for an asset on Energex's distribution system, Energex must insert additional rows below the relevant asset group to account for this. Energex must provide the required data, applying a high level descriptor of the asset as the category name. The line item titled "OTHER – PLEASE ADD A ROW IF NECESSARY AND NOMINATE THE CATEGORY" illustrates this requirement. Energex must ensure that the sum of the individual asset categories, including any additional sub-category, additional other asset category or asset refurbishment/ life extension asset category expenditure reconciles to the total expenditure of the asset group.	Demonstrated in section 2.5 - Explanatory notes and the Basis of Preparation for Regulatory Template 5.2 – Asset Age Profile.
Energex must ensure that the replacement volumes by asset group is equal to the applicable replacement volume data provided in Table 2.2.2.	Demonstrated in Step 8 – Final consistency check against RIN Table 2.2.2 below.
Energex must ensure that the sum of the asset group replacement expenditures is equal to the total replacement expenditure contained in Regulatory Template 2.1.	Demonstrated in Basis of Preparation for Regulatory Template 2.1 - BoP 2.1.1 – Expenditure Summary & Reconciliation

Estimated Information was provided for all variables.

2.2 Sources

- The key data source used to produce figures for replacement expenditure and asset replacement volumes was EPM, Planning Approval Reports, project scope statements and project estimates and network program project commissioning reports.
- SCADA, network control and protection systems asset replacement data was sourced from a range of project management systems including SIFT, Ellipse, Report Explorer and the Energex intranet.

Table 2.2 below sets out the sources from which Energex obtained the required information.

Table 2.2: Information sources

	Variable	Source
Expenditure dollar values	Poles	EPM

	Variable	Source
	Pole top structures	EPM
	Overhead conductors	EPM
	Underground cables	EPM
	Service lines	EPM
	Transformers	EPM
	Switchgear	EPM
	Public lighting	EPM
	SCADA, network control and protection systems	EPM
Volume of asset replacements	Poles	EPM, Planning approval reports, Scope statement, project estimates,
	Pole top structures	EPM
	Overhead conductors	EPM, Planning approval reports, Scope statement, project estimates
	Underground cables	EPM, Planning approval reports, Scope statement, project estimates
	Service lines	EPM
	Transformers	EPM, Planning approval reports, Scope statement, project estimates, network program project commissioning reports
	Switchgear	EPM, Planning approval reports, Scope statement, project estimates, network program project

	Variable	Source
		commissioning reports
	Public lighting	EPM
	SCADA, network control and protection systems	SIFT, Ellipse, Report Explorer, Energex Intranet, network program project commissioning reports
List of commissioned projects	Overhead conductors	SIFT, Ellipse, Report Explorer, Energex Intranet, network program project commissioning reports
	Underground cables	
	Transformers	
	Switchgear	

2.3 Methodology

2.3.1 Assumptions

- At present, Energex does not report replacement expenditure according to the asset categories listed in RIN Table 2.2.1. In order to satisfy the data requirements in RIN Table 2.2.1, Energex had to develop a methodology of allocating replacement expenditure to the Repex asset categories.
- Asset replacement volumes are based on the project commissioning date.
- For each project that was analysed as part of RIN Table 2.2.1, Energex has calculated a value of the materials expenditure against each of the Repex asset categories. The materials expenditure for Repex asset categories has been converted into weighted averages, based on the materials expenditure in each Repex asset category relative to the total materials expenditure for the project. The weighted average values calculated for each Repex asset category was used as a basis for allocating total project expenditure to Repex asset categories.
- Public lighting projects included in Regulatory Template 4.1 were excluded from RIN Table 2.2.1.
- Overhead conductor and underground cable replacement volumes were provided as “km”.

- In relation to the asset group “SCADA, Network Control and Protection Systems”, if an indoor circuit breaker was replaced, it was assumed that an intelligent electronic device (IED) was also replaced; and
- If a circuit breaker or ground mounted transformer was replaced the Local Wiring Asset was also replaced.

2.3.2 Approach

The following two approaches were applied to derive these values for replacement expenditure and replacement volumes against the Repex asset categories based on the current stage of the project.

Step 1 – Replacement project data extraction

- A report was run from EPM Business Objects which listed all replacement projects that incurred expenditure between the years 2008-09 and 2013-14 under the replacement financial activity codes detailed in Table 2.3 below:

Table 2.3 – Replacement financial activity codes

Activity Code	Description
C2040	CWT Asset Replacement - Transmission
C2540	Refurbishment Ageing Equipment
C2545	Pole Reinstatement

- This report provided a list of all transactions incurred on replacement projects over the five year period, with the exception of replacement volumes relating to the following activities:
  - Pole nailing
  - SCADA, Network Control and Protection Systems

Step 2 – Analysis of materials expenditure transactions

- Material transaction records were used to allocate expenditure to the Repex asset categories for all projects, except for open projects. The open projects are discussed in Step 6 below.
- Once a list of replacement project transactions was identified, detailed analysis was undertaken of the materials costs associated with each transaction. The purpose of this analysis was to assign each unique material cost to an appropriate Repex asset category. Establishing a relationship between material costs and Repex asset

categories provided a basis for allocating total project expenditure across Repex asset categories (discussed in Step 5).

- This mapping process was undertaken by:
  - Identifying a subset of material cost transactions to be mapped to Repex asset categories. Due to the large volume and type of materials transactions, Energex constrained its analysis to the most meaningful materials transactions, based on material value (this accounted for over 85% of all material spend); and
  - Allocating each material cost transaction to a Repex asset category, based on the stock code associated with the material.

Step 3 – Aggregation of expenditure values and replacement volumes at the project level

- Following the analysis of materials costs, a separate summary table was created listing each project identified under Step 1 with the following information:
  - Total expenditure incurred on each project. Expenditure at the project level was based on the summation of each transaction relevant to the project.
  - The volume of materials associated with each project, disaggregated by Repex asset category. This information was sourced from the analysis of material undertaken in Step 2.
  - Materials expenditure associated with each project, disaggregated by Repex asset category. This was sourced from the analysis of materials undertaken in Step 2.
  - Materials expenditure associated with each project, disaggregated by Repex asset category, as a percentage of total Repex material expenditure for the project (that is, a weighted average of materials expenditure).

Step 4 – Material cost and volume adjustments

- A number of manual adjustments were made to account for materials data (either expenditure or volume) not captured in the EPM Business Objects report, prepared in Step 1. These adjustments were input into an Excel summary sheet, similar in structure to the table prepared under Step 3.

Pole nailing

- Pole nailing projects were included in the extract from EPM, however, pole nailing is performed by contractors and the volume of materials used are not captured as in the same manner as the other asset categories. Therefore, the volume of pole nailing undertaken by each replacement project was captured through a separate EPM physicals report and these volumes were entered as a manual adjustment across the relevant Repex asset categories.

Poletop Structures with unknown voltage

- The material analysis was able to determine the voltage of crossarms for approximately half of the asset replacements. The remaining assets with unknown voltages were allocated to the voltage ranges based on the proportion of assets with known voltages.

SCADA, Network Control and Protection Systems

- to enhance efficiencies, Energex plans and undertakes communication asset replacement projects in conjunction with other projects occurring at the same site where possible. These other projects may be refurbishment or augmentation in nature.
- In order to determine the expenditure values and asset volumes of communications assets replaced as part replacement projects, a detailed review of replacement projects was undertaken. Specifically, this involved reviewing individual project files and engineering specifications to identify the assets, and associated costs of the assets, which would be replaced as part of the project.
- Both the replacement volumes and materials costs were mapped to a Repex asset category and input as a manual adjustment.

Other SCADA and Protections Assets (Fibre cables)

- Fibre optic communications cables were included as an additional asset category. This is due to the cables being linear assets as compared with the communications network assets included above.
- The materials expenditure analysis (Step 2) captured the material cost associated with the replacement of copper pilot cables with fibre cables; however, the volume of fibre cables was not quantified. To quantify the fibre cable replacement volumes, Energex undertook a review of specific replacement projects which contained a large component of fibre installation, and used this as a basis for estimating the replacement volumes. These volumes were included as a manual adjustment.

Known commissioned projects

- A number projects commissioned early in the period had materials that were purchased prior to 2008-09 or assets replaced under warranty. These materials were not captured in the EPM Objects report prepared in Step 1. This included the projects detailed in Table 2.4 below:

Table 2.4 – Projects not captured

Project Code	Description	Commissioning Date
C0122079	BLH BEENLEIGH Replace 110kV CB7872	2008-09
C0083637	VAR - On Cond Replacement of Sub Plant	2008-09

Project Code	Description	Commissioning Date
C0107253	BMT BLACK MOUNTAIN Replace regulator RG1 (plant no. RG4971)	2008-09
C0148001	LTA LOTA Replace existing TR1 33/11kV 12.5MVA with 25MVA transformer	2010-11
C0208815	VSP Replace Transformer TR1(TR53871) under warranty	2011-12

- The cost and volume of replacement materials associated with these projects were identified by a detailed review of the planning approval reports and engineering specifications. This data was mapped to relevant Repex asset categories and included as a manual adjustment.

Step 5 – Allocation of total project costs to Repex asset categories

- To allocate total project expenditure across each Repex asset category, the total project expenditure was applied to the weighted average materials expenditure associated with the Repex asset category [1]. This provided an estimate of total project cost by Repex asset category.
- The total project cost allocated to each Repex asset category was then summated across all projects to provide an overall estimate of the expenditure for each Repex asset category. These values were then input to RIN Table 2.2.1.

An example is provided below to illustrate how the process of allocation occurs.

Example:

Consider a project which incurred $40 million of expenditure over the 5 years between 2009-10 and 2013-14, as detailed in Table 2.5 below:

Table 2.5 – Project expenditure example (a)

Year	Expenditure ($m)
2009-10	$5
2010-11	$10
2011-12	$12
2012-13	$9

[1] This included the data collected under Step 3 and Step 4

2013-14	$4
Total project expenditure	***$40***

Assume that the project used three types of material which were mapped to the Repex asset categories outlined below. In this example, the cost of materials summed to $27 million, meaning that $13 million of other costs (labour, contractors and other costs needed to be allocated across Repex asset categories – refer to Table 2.6 below:

Table 2.6 – Project expenditure example (b)

Repex asset category	Cost of materials ($m)	Percentage of total materials cost
Poles: > 132 kV; WOOD	$5	19%
Underground cables: > 132 kV	$12	44%
Transformers: POLE MOUNTED ; > 22 kV ; > 60 kVA AND < = 600 kVA	$10	37%
Total cost of materials	***$27***	***100%***

The total project cost allocated to a particular Repex asset category is calculated as the product of total expenditure for each year and the percentage of total materials cost for that Repex asset category. This calculation is outlined in Table 2.7 below:

Table 2.7 – Project expenditure - total expenditure calculations

Year	Repex asset category			***Total project expenditure by year***
	Poles: **> 132 kV; WOOD**	**Underground cables:** **> 132 kV**	**Transformers:** **POLE MOUNTED ; > 22 kV ; > 60 kVA AND < = 600 kVA**	
2009-10	$0.95 ($5 x 19%)	$2.2 ($5 x 44%)	$1.85 ($5 x 37%)	*$5*
2010-11	$1.9 ($10 x 19%)	$4.4 ($10 x 44%)	$3.7 ($10 x 37%)	*$10*
2011-12	$2.28 ($12 x 19%)	$5.28 ($12 x 44%)	$4.44 ($12 x 37%)	*$12*
2012-13	$1.71	$3.96	$3.33	*$9*

Year	Repex asset category			Total project expenditure by year
	Poles: **> 132 kV; WOOD**	**Underground cables:** **> 132 kV**	**Transformers:** **POLE MOUNTED ; > 22 kV ; > 60 kVA AND < = 600 kVA**	
	($9 x 19%)	($9 x 44%)	($9 x 37%)	
2013-14	$0.76 ($4 x 19%)	$1.76 ($4 x 44%)	$1.48 ($4 x 37%)	*$4*
Total project expenditure by Repex asset category	***$7.6***	***$17.6***	***$14.8***	***$40***

Step 6 – Allocation of remaining projects

- The remaining open projects used forecasts of major plant items to allocate expenditure to the Repex asset categories. The volumes of assets were determined through a review of project documentation including Planning Approval Reports, scope statements and project estimates.
- The project review was undertaken to ensure that major plant items not yet issued to projects were able to be included in the material allocation process. Expenditure was calculated using same the process outlined in steps 4 and 5 above.

Step 7 – Data consolidation

- The replacement expenditure of both sets of projects were consolidated and entered into RIN table 2.2.1.

Step 8 – Final consistency check against RIN Table 2.2.2

- Energex ensured that the “replacement volumes by asset group” was equal to the applicable replacement volume data provided in RIN Table 2.2.2.

2.4 Estimated Information

All data is Estimated Information due to the judgements that were made during the categorisation of expenses and quantities.

2.4.1 Justification for Estimated Information

As discussed, Energex does not capture costs or quantities in the categories required in Tables 2.2.1. As such Energex had to manually categorise each into the categories required.

SCADA, Network Control and Protection Systems

- Energex made the assumption that if an indoor circuit breaker was replaced, an intelligent electronic device (IED) also replaced at the same time. Local Network Wiring assets were also assumed to be replaced with transformers and circuit breakers.
- The rationale for this assumption and associated estimate was on the basis that project scope documentation did not go down to a level of detail necessary to identify replacement volumes for low cost items.

2.4.2 Basis for Estimated Information

- Each cost and quantity was manually categorised using multiple descriptors within the data. For full details refer to the approach section above.
- The volume of the assets replaced was validated against a list of projects commissioned during the five year period.

2.5 Explanatory notes

General issues

- In distribution businesses it is very common for projects to span a number of years depending on the complexity of the project. However, the Reset RIN and previous Category Analysis RIN require expenditure to be reported on an as incurred basis. This definition leads to a disconnect between replacement expenditure and replacement volumes. For example, if a project spans five years the bulk of the expenditure may occur in the third year based on the purchase of major items, however the project may not be commissioned until the fifth year.
- Only projects with a primary replacement driver have been included in this analysis. As a result, assets replaced due to condition, as part of an augmentation driven project, were not included in this analysis.

Asset specific issues

- Service line replacement programs were not included as they are not categorised as Repex activities in the current regulatory period, instead they were included as connections activities in Regulatory Template 2.5 Connections.
- Public lighting replacement programs were categorised as augmentation in the first two years until they were categorised as ACS. The programs included a mixture of replacement and augmentation projects. They were detailed in Regulatory Template 4.1 Public Lighting.

Other asset categorisation

- Energex identified a number of asset replacement categories with spend in 2013/14 that extend in the forecast regulatory periods. These programs/projects spend were listed in the other (DNSP defined) at the bottom of the template. These assets are:
- NER, OHEW, Reactive work (Various Sub transmission Plant), Fuse Protection, 11kV Falcon RMU, Surge Arrestor, Swipe Card Access.

Projects with no materials allocated

- The allocation of project cost to the Repex asset categories was largely based on analysis of the stock issues to the projects. Where projects did not have any materials issued the expenditure was not included in RIN Table 2.2.1. The project expenditure not allocated in RIN Table 2.2.1 is included as a balancing item in Regulatory Template 2.1.

The annual expenditure not allocated in the Repex model is shown in Table 2.8 below:

Table 2.8 – Annual expenditure not allocated to Repex

Spend 2009 FY	Spend 2010 FY	Spend 2011 FY	Spend 2012 FY	Spend 2013 FY	Spend 2014 FY
6,040,178	2,713,274	4,551,167	8,646,028	14,584,869	$15,060,500

3 BoP 2.2.2 – Repex – Asset Failures by Category

In relation to RIN Table 2.2.1, the AER requires Energex to provide asset failure volumes for the year 2013-14 for the following asset groups:

- **Poles, disaggregated by highest operating voltage and material type**
- **Pole top structures, disaggregated by highest operating voltage**
- **Overhead conductors, disaggregated by highest operating voltage and number of phases**
- **Underground cables, disaggregated by highest operating voltage**
- **Service lines, disaggregated by, connection voltage, customer type and connection complexity**
- **Transformers, disaggregated by mounting type, highest operating voltage, ampere rating and number of phases**
- **Switchgear, disaggregated by highest operating voltage and switch function**

Estimated Information was supplied for Public Lighting variables.

Actual Information was provided for all other components of submitted data.

These variables are a part of Regulatory Template 2.2 – Repex.

3.1 Consistency with Reset RIN Requirements

Table 3.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The number of asset failures must be reported against the Asset Category. An asset failure is defined as the failure of an asset to perform its intended function safely and in compliance with Jurisdictional regulations. It excludes external impacts such as: • extreme or atypical weather events • third party interference, such as traffic accidents and vandalism • wildlife interference, but only where the wildlife interference directly, clearly and unambiguously influenced asset performance • vegetation interference, but only where the vegetation interference directly, clearly and unambiguously influenced asset performance	Demonstrated in section 3.3

Requirements (instructions and definitions)	Consistency with requirements
It also excludes planned interruptions.	

Estimated data was supplied for Public Lighting variables.

Actual Information was provided for all other components of submitted data.

3.2 Sources

A number of systems were used to extract asset failure information, as outlined in Table 3.2 below.

Table 3.2: Information sources

Variable	Source
Poles Failures	In-service Pole Failure Register
Pole Top Structures Failures	NFM NO EPM (For the period 25/5/2014 to 30/6/2014)
Overhead Conductors Failures	NFM NO EPM (For the period 25/5/2014 to 30/6/2014)
Underground Cables Failures	NFM NO EPM (For the period 25/5/2014 to 30/6/2014)
Service Lines Failures	SCM SO
Transformers Failures	(110kV/132kV/33kV) Power Transformer Issues Register (Distribution Transformer) NFM NO EPM (For the period 25/5/2014 to 30/6/2014)
Switchgear Failures	(>= 33kV Circuit Breakers) Network Investigation Report (All other types) NFM NO

3.3 Methodology

- Failure data was extracted from the relevant source systems for each Asset Category for the current reporting period and filtered to ensure only inherent functional failures were included. This was achieved by excluding particular failure codes, using key word searches and analysing failure descriptions. Each failure event has the date recorded, enabling it to be counted in the appropriate year.

- It must be noted that during this reporting period there was a change in reporting processes. This has resulted in the use of a report obtained from the corporate performance reporting system (EPM) to obtain information on outages occurring during the period from 25/5/2014 to 30/6/2014.

3.3.1 Assumptions

- For Overhead Conductor, Underground Cable and Service Line Asset failures, the quantity of failure events in the year is reported, not the length of failed asset.

- For street light luminaires and lamps, asset replacement volumes were used as a proxy for asset failures. Whilst some of the replacements will be based on asset failures, this information is not reported in Energex's systems.

3.3.2 Approach

- A level of consistency in data extraction and filtering was maintained wherever practically possible throughout the reporting process.

- For each Asset Category, the failure rate data was extracted from the source systems into a central working spreadsheet ("AER_CA_RIN_Asset Failures"). A separate worksheet was created within the central working spreadsheet for every voltage level/reporting category within each asset category. The 'Advanced Filter' tool was used in Microsoft Excel to assist with filtering the data into the relevant categories – this ensured that any filtering criteria used were clearly visible in each worksheet.

Poles Failures

- All in-service pole functional failures are investigated and recorded in a pole failure register by the Network Maintenance & Performance Group within Asset Management. This register is consistent with the AER requirements and definitions, enabling the data to be extracted without further analysis.

- This data was included in the central working spreadsheet with an additional 'FLAG' column to indicate the relevance for each category. The flagged data was collated for each of the relevant sub-categories in the RIN Table 2.2.1.

Pole Top Structures Failures

- Pole top structures failure outage data for the period 01/07/2013 to 24/05/2014 was extracted into the central working spreadsheet from the Network Outage system from NFM (Network Facilities Management) (NFM). The failure outage data for the period 25/05/2014 to 30/06/2014 was extracted from the EPM report and also placed in the central working spreadsheet. Failure outage data based on specific cause codes (e.g. third party, vegetation, weather, underground, substation, wildlife, etc.) was excluded whilst specific text filters were utilised to identify the relevant data.

- The filtered data was analysed in detail by examining the 'fault' description and 'action taken' description entered by the Network Operator. All of the failure data was analysed in detail, with an additional 'FLAG' column added to the spreadsheet to indicate whether the data was to be included or excluded (any data that was erroneous was not included in the spreadsheet). The total asset failures were then collated for each of the relevant sub-categories in RIN Table 2.2.1.

Overhead Conductors Failures

- Overhead conductor failure outage data for the period 01/07/2013 to 24/05/2014 was extracted into the central working spreadsheet from the Network Outage system from NFM (Network Facilities Management) (NFM). The failure outage data for the period 25/05/2014 to 30/06/2014 was extracted from the EPM report and also placed in the central working spreadsheet. Failure outage data based on specific cause codes (e.g. third party, vegetation, weather, underground, substation, wildlife, etc.) was excluded. Any outage data with an underground cause code or a part code indicating underground or crossarm was also excluded.

- The data was analysed in detail by examining the 'fault' description and 'action taken' description entered by the Network Operator. All of the failure data was analysed in detail, with an additional 'FLAG' column added to the spreadsheet to indicate whether the data was to be included or excluded (any data that was erroneous was not included in the spreadsheet). The total asset failures were then collated for each of the relevant sub-categories in RIN Table 2.2.1.

Underground Cables Failures

- Underground conductor failure outage data for the period 01/07/2013 to 24/05/2014 was extracted into a central working spreadsheet from the Network Outage system from NFM. The failure outage data for the period 25/05/2014 to 30/06/2014 was extracted from the EPM report and also placed in the central working spreadsheet. Filtering techniques involved the inclusion of data containing the specific cause code for underground equipment failure (this excludes for example: third party, vegetation, weather, substation, wildlife). It must be noted that failures of pillars were not included as underground cables failures.

- The data was analysed in detail by examining the 'fault' description and 'action taken' description entered by the Network Operator. All of the failure data was analysed in detail, with an additional ‘FLAG’ column added to the spreadsheet to indicate whether the data was to be included or excluded. The total asset failures were then collated for each of the relevant sub-categories in RIN Table 2.2.1.

Service Lines Failures

- A filtered set of service line failure service order data was extracted into the central working spreadsheet from the Service Call Management (SCM) system from NFM using specific fault descriptions (Faulty Service, Service Fittings broken, Service tail failure, etc.).Pivot tables were created to break the data up into overhead and underground failure reports based on the specific fault descriptions mentioned above. Samples of the overhead[2] and underground[3] failure data were tested.

- The overhead data error rate (12%) was considered acceptable and as a result, all of the filtered overhead figures were included in calculations. The underground data error rate was considered unacceptable and therefore each line item in the underground description was analysed in detail by reading the ‘service order’ description entered by the Network Operator. A ‘FLAG’ column was added to indicate whether this analysed data was to be included in the calculations.

- The sum of flagged underground failures and overhead failures was then split up[4] into the respective ‘Residential’ and ‘Commercial & Industrial’ categories in RIN Table 2.2.1.

Transformers Failures

- For 11 kV distribution transformer failures; outages involving in-service failure data are identified in the Network Outage NFM for the period 01/07/2013 to 24/05/2014 and from EPM for the period 25/05/2014 to 30/06/2014. This data was included in the central working spreadsheet. The initiating component identifier was used to filter for the relevant outages. The outages already included in previous reports were also removed from consideration. The remaining filtered failure data was analysed in detail, with an additional ‘FLAG’ column added to the spreadsheet to indicate whether the data was to be included or excluded. The total asset failure figures were then collated for each of the relevant sub-categories in RIN Table 2.2.1.

- Power transformer asset failures in the primary voltage range 132 kV to 33 kV are collected after investigation and recorded in the Power Transformer Issues Register by the Network Maintenance & Performance Group within Asset Management. This register is consistent with the AER requirements and definitions, enabling the data to be extracted without further analysis. This data was included in the central working spreadsheet to collate the total asset failures for each of the relevant sub-categories in RIN Table 2.2.1.

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[2] The sample comprised 474 line items, representing 38% of the data
[3] The sample comprised 271 line items, representing 32% of the data
[4] The split was based on customer number proportions from Energex’s corporate system.

Switchgear Failures

- All in-service circuit breakers failures are investigated and recorded in the Network Investigations Report Register by the Network Maintenance & Performance Group within Asset Management. This register is consistent with the AER requirements and definitions, enabling the data to be extracted without further analysis. This data was extracted into the central working spreadsheet to collate the total asset failures for each of the relevant sub-categories in RIN Table 2.2.1.

- For switchgear failures, outages involving in-service failure data are identified in the Network Outage NFM for the period 01/07/2013 to 24/05/2014 and from EPM for the period 25/05/2014 to 30/06/2014. This data was included in the central working spreadsheet. The outages already included in other categories were filtered out. All of the filtered failure data was analysed in detail, with an additional 'FLAG' column added to the spreadsheet to indicate whether the data was to be included or excluded. The total asset failures were then collated for each of the relevant sub-categories in RIN Table 2.2.1.

Public Lighting Failures

- For street light luminaires and lamps, asset replacement volumes have been used as a proxy for asset failures. Whilst some of the replacements will be based on asset failures, this information is not reported in Energex's systems.

Public Lighting Failures - Luminaires and Lamps

- Energex does not report asset failure data for street light luminaires and lamps. The information provided in template 2.2 for luminaires and lamps reflects the volume of luminaires and lamps replaced as part of Energex's three street light maintenance contracts (C-08042 SL Patrols, C-07018 SL Repair and Construction and C-10214 SL Maintenance, Construction and Patrols6).

- Whilst some of the replacements will be based on asset failures, this information is not reported in Energex's systems. The information below steps out how this information was obtained:
  - A project work order transaction report was run from Report Explorer ELL00159 against the work orders relevant to the public lighting three public maintenance contracts (that is, 1839810, 1656695, 1656694, 3482304, 3482365 and 3482366) for the relevant F/Y.
  - This report detailed all expenses against each of the maintenance projects over the five year period.
  - A detailed analysis was then done on each expense line item to determine the volume of luminaires and lamps used for maintenance. This process of asset identification, which was performed by material stock code, also identified for each luminaire and lamp, whether is it was for a major road or a minor road.

- The number luminaires and lamps for each year (by major road and minor road) was then summed together to provide a proxy for the total annual value for asset failures.

Public Lighting Failures - Brackets

- The volume of bracket failures was reported as nil for each year on the basis that Energex has not reported any brackets failures during the reporting period.

SCADA, Network Control and Protection Systems Failures

- Failure rates for SCADA, Network Control and Protection Systems assets were obtained by evaluating repair work orders. The first step in the process was to extract a list of all work orders relating to the failure of service / equipment from Ellipse. If the work order showed there was a loss of function of an asset, this was categorised as an asset failure and allocated against an appropriate asset category in the year in which it occurred. Data at the work order level was then collated to provide the total number of asset failures for each asset category for the 2013/14 regulatory year.

3.4 Estimated Information

Data for public lighting was estimated.

3.4.1 Justification for Estimated Information

Public lighting data was estimated as Energex does not capture the data required.

3.4.2 Basis for Estimated Information

For a description of the methodology for Public Lighting Estimated Information please refer to the section 3.3 Methodology above.

4 BoP 2.2.3 – Repex – Asset Characteristics

The AER requires Energex to provide the following information relating to RIN Table 2.2.2 – Selected Asset Characteristics:

- **Total Poles By: Feeder Type**
- **Overhead Conductors By: Conductor Length By Feeder Type**
- **Overhead Conductors By: Conductor Length Material Type**
- **Underground Cables By: Cable Length By Feeder**
- **Transformers By: Total MVA**

Actual Information was provided for asset volumes currently in commission for each category and for all transformer asset replacements.

All other asset replacement figures are Estimated Information.

These variables are a part of Regulatory Template 2.2 – Repex.

4.1 Consistency with Reset RIN Requirements

Table 4.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 4.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must provide total volume of assets currently in commission and replacement volumes of certain asset groups by specified aggregated metrics. In instances where this information is estimated Energex must explain how it has determined the volumes, detailing the process and assumptions used to allocate asset volumes to the aggregated metrics.	This requirement was addressed in the preparing RIN Table 2.2.2

Actual Information was provided for asset volumes currently in commission for each category and for all transformer asset replacements.

All other asset replacement figures are Estimated Information.

4.2 Sources

Table 4.2 over page sets out the sources from which Energex obtained the required information.

Table 4.2: Information sources

Variable	Source
Assets Volumes Currently in Commission	
Total Poles By: Feeder Type	NFM
Overhead Conductors By: Conductor Length By Feeder Type	NFM
Overhead Conductors By: Conductor Length Material Type	NFM
Underground Cables By: Cable Length By Feeder	NFM
Transformers By: Total MVA	NFM
Asset Replacements	
Total Poles By: Feeder Type	Other variables within Tables 2.2.1 and 2.2.2.
Overhead Conductors By: Conductor Length By Feeder Type	Other variables within Tables 2.2.1 and 2.2.2.
Overhead Conductors By: Conductor Length Material Type	Other variables within Tables 2.2.1 and 2.2.2.
Underground Cables By: Cable Length By Feeder	Other variables within Tables 2.2.1 and 2.2.2.
Transformers By: Total MVA	NFM

4.3 Methodology

4.3.1 Assumptions

Asset Volumes Currently in Commission

Total Poles By: Feeder Type

- The pole data does not include assets that are in store or held for spares.
- Only poles with a connected voltage of Low Voltage or higher were included, therefore streetlight, bollard and cross-street service poles were not included in this value (195,996 of 594,772 poles).
- Only a single feeder type can exist for a pole and will be derived from a feeder associated with the site containing the pole.

Overhead Conductors by: Conductor Length by Feeder Type

- The overhead conductor data does not include assets that were in store or held for spares.
- Feeder type will be derived from the feeder category.

Overhead Conductor by: Conductor Length Material Type

- The overhead conductor data does not include assets that were in store or held for spares.
- Only one conductor type can exist per span.

Underground Cable by: Cable Length by Feeder Type

- The underground cable data does not include assets that were in store or held for spares.
- Feeder type will be derived from the feeder category.

Transformer by: Total MVA

- All data derived from NFM which is generally not the usual source for all capacity data. This is because the usual system, SIFT, is used for sub-transmission capacity, however this system is unable to determine replacement and disposal information.

Asset Replacements

- All asset replacements for the following classifications were proportioned evenly by feeder classicisation and material type:
  - Total Poles By: Feeder Type;
  - Overhead Conductors By: Conductor Length By Feeder Type;
  - Overhead Conductors By: Conductor Length Material Type; and
  - Underground Cables By: Cable Length by Feeder.
- Replacement of Power Transformers will have a material effect on the values reported.

POWER TRANSFORMERS (MVA)	***2013/14***
TOTAL MVA REPLACED	0
TOTAL MVA DISPOSED OF	0

4.3.2 Approach

Energex applied the following approach to obtain the required information:

Asset Volumes Currently in Commission

Total Poles By: Feeder Type

1) Core NFM tables were denormalised and snapshot taken as at the end of the financial year 2013/14 (30/6/2014) and stored in the schema RIN.
    a. Current feeder categories were used to determine the feeder category as a number of data corrections happened post EOF 2013/14 period which needed to be applied to the data.
    b. LV network inherited the feeder category of the 11kV feeder delivering the supply to the network.
    c. Where a site has multiple connections the pole within the site inherited a category based on the following order:
        i. Urban
        ii. Rural
        iii. CBD (High-Density)
2) The extract was run from the RIN schema using the script FeederPoleCategory_2014_v01_00.sql:
    a. All sites with a grade code of W were excluded as W sites are customer owned sites.
    b. Plastic Poles were also excluded (24 Poles in total).
3) Results were extracted to Excel file Pole_Feeder_Cat_V01_00.xls
    a. Poles that did not have a feeder allocated (195,996 poles) were excluded from the reported pole numbers. These included:
        i. Poles with only decommissioned cables
        ii. Streetlight poles with only street lighting
        iii. Bollard poles
        iv. Cross street service poles

Overhead Conductors by: Conductor Length by Feeder Type

1) Core NFM tables were denormalised, a snapshot taken as at the end of the financial year 2013/14 (30/6/2014) and stored in the schema RIN.

2) An extract was run from the RIN schema using the script FeederCategory_2014_v01_00.sql :

   a. Conductors were not allocated an ownership value, which generally means that customer owned conductors were not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets. When this occurred Energex captured these conductors. In addition, assets that were sold to customers and there are benefits in continuing to store this data the data was not removed from NFM.

      To minimise the effect of captured customer conductors, it was assumed that where a conductor is connected to only customer assets then that conductor was also customer owned and excluded.

Estimated Customer Conductor	*Quantity (km)*
Unknown Category	0.55
Urban	2.85
Rural	4.67

3) Information was extracted to Excel file CatLineLength_v01_00.xls.

4) Within Excel file conductors with an unknown category (342.21km) were pro-rated into categories CBD, Urban and Rural based on existing ratios.

Conductors Category	*Percentage*	*Quantity (km)*
CBD (High-Density)	0.06%	0.19
Rural	61.90%	211.84
Urban	38.91%	130.18

Overhead Conductor By: Conductor Length Material Type

1) Core NFM tables were denormalised, snapshot taken as at the end of the financial year 2013/14 (30/6/2014) and stored in the schema RIN as tables Conductor_Age_2014 and SEGMENT_CUSTOMER_2014.

2) An extract was run from the RIN schema using the script ConductorType_2014_v01_00.sql

   a. Conductors are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets, when this occurs Energex has captured these conductors captured. In addition assets that have been sold to customers and Energex believes there is a benefits to continue to store this data the data has not be removed from NFM.

To minimise the effect of captured customer conductors, it was assumed that where a conductor is connected to only customer assets then that conductor was also customer owned and excluded.

Estimated Customer Conductor	*Quantity (km)*
AAAC	0.1
HDBC	1.47
ACSR	4.02
AAC	2.61

b. Only overhead conductors were extracted.

c. Where different conductor types existed for a single span the material with the maximum code value was used. Generally this will result in the following preference, affecting a non-material portion of conductors (3.85km / 0.01% of conductors):

   i. OH conductor LV ABC
   ii. OH conductor Steel
   iii. OH conductor ACSR
   iv. OH conductor AAAC
   v. OH conductor AAC
   vi. OH conductor HDBC

d. OH Conductor ABC were split to OH conductor HVABC and OH conductor LV ABC as Energex has ABC used for LV and 11KV. The OH Conductor HV ABC was added to the total for OH Conductor AAC.

Estimated ABC Cable	*Quantity(km)*
LV ABC	2984.36
HV ABC	41.65

3) Information was extracted to Excel file LineTypeLength_v01_00.xls.

4) The detailed conductor types were manually rolled up to OH Conductor ABC, OH conductor Steel, OH conductor ACSR, OH conductor AAAC, OH conductor AAC, OH conductor HDBC

5) The detailed conductor types roll up allocation was then validated by the Maintenance Department to ensure data integrity.

6) Within the Excel file, conductors with an unknown conductor type (26.24 km) have been pro-rated into categories OH conductor ABC, OH conductor Steel, OH conductor ACSR, OH conductor AAAC, OH conductor AAC, OH conductor HDBC based on existing ratios.

Conductors Category	***Percentage***	***Quantity (km)***
Steel	2.63%	0.690103239
Conductor ABC	8.51%	2.231580937
AAAC	0.43%	0.113776241
HDBC	20.20%	5.299166437
AAC	47.27%	12.40277324
ACSR	20.96%	5.49807991

Underground Cables by: Cable Length by Feeder Type

1) Core NFM tables were denormalised, snapshot taken as at the end of the financial year 2013/14 (30/6/2014) and stored in the schema RIN.

2) The Extract was run from the RIN schema using the script FeederCategory_2014_v01_00.sql

   a. Conductors are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets. When this occurred Energex captured these conductors. In addition, assets that were sold to customers and there are benefits in continuing to store this data the data was not removed from NFM.

      To minimise the effect of captured customer conductors, it was assumed that where a conductor is connected to only customer assets then that conductor was also customer owned and excluded.

Estimated Customer Cable	***Quantity (km)***

Estimated Customer Cable	*Quantity (km)*
Unknown Category	0.22
Urban	11.94
Rural	1.86

b. 110/132kV feeders 711 & 712 were excluded as they were identified as Non-Energex feeders.

Excluded Cables	*Quantity (km)*
Unknown Category	44.22

3) Information was extracted to Excel file CatLineLength_v01_00.xls.

4) Within Excel file cables with an unknown category (19.46km) were pro-rated into categories CBD, Urban and Rural based on existing ratios.

Cables Category	*Percentage*	*Quantity (km)*
CBD (High-Density)	1.24%	0.24
Rural	28.85%	5.62
Urban	69.91%	13.61

Transformer By: Total MVA

1) Core NFM tables were denormalised, a snapshot taken as at the end of the financial year 2009/10 to 2013/14 and stored in the schema RIN.

2) An extract was run from the RIN schema using the script Capacity_Transformer_v01_00.sql from the years 2009/10 to 2013/14.

3) Current Capacity was the summation of all known Rated Outputs for the end of financial year 2013/14.

Asset Replacements

1) The following variables were calculated from values contained in RIN Tables 2.2.1 and 2.2.2:

   a. Total Poles By: Feeder Type;

   b. Overhead Conductors By: Conductor Length By Feeder Type;

c. Overhead Conductors By: Conductor Length Material Type; and

d. Underground Cables By: Cable Length By Feeder.

2) Asset replacement volumes for the specific asset groups have been calculated by taking the total number of assets replaced from table 2.2.1 and apportioning the replacements based on the asset volumes currently in commission from table 2.2.2. For example. The total number of poles of all voltages replaced in 2013/14 is spread between CBD, Urban; and Rural short poles based on the volumes currently in service.

3) Energex was required to add overhead conductor material types. Energex broke down the assets by OH Conductor ABC, OH conductor Steel, OH conductor ACSR, OH conductor AAAC, OH conductor AAC, OH conductor HDBC

Transformer By: Total MVA

1) Core NFM tables were denormalised, a snapshot taken as at the end of the financial year 2009 to 2014 and stored in the schema RIN.

2) An extract was run from the RIN schema using the script Capacity_Transformer_v01_00.sql from the years 2009 to 2014.

3) Information was extracted into individual Excel files: TX_yyyy_v03_01.xls (yyyy = year of extract).

4) Excel files were consolidated into excel file TX_Combined_v03_01.xls.

5) Within the Excel file the transformers were compared to previous year to determine disposal and replacement MVA quantities as follows:

   a. The previous year asset was compared to the asset installed in the relevant year and if the assets were different it was deemed to be a replacement.

   b. The rated output of the asset from the previous year was deemed to be the disposal value.

   c. The rated output of asset in the relevant year was deemed to be the replacement value.

4.4 Estimated Information

Data for asset replacement volumes for the following is Estimated Information:

- Total Poles By: Feeder Type;
- Overhead Conductors By: Conductor Length By Feeder Type;
- Overhead Conductors By: Conductor Length Material Type; and
- Underground Cables By: Cable Length By Feeder.

This is due to the judgements made during the categorisation of the quantities.

All asset volumes are Actual Information as the pro-ration does not materially affect the reported numbers.

4.4.1 Justification for Estimated Information

Energex does not capture costs or quantities in the categories required in RIN Tables 2.2.2. As such Energex was required to manually categorise each into the categories required.

4.4.2 Basis for Estimated Information

Replacement volume for the specific asset groups was based on the total volume of asset replaced in RIN Table 2.2.1. RIN Table 2.2.1 only included assets that were replaced under Repex projects; therefore it is the most reliable source for asset replacement volumes as per the AERs definitions.

4.5 Explanatory notes

Energex does not have any rural long feeders.

5 BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics

RIN Table 2.3.1 and 2.3.2 include both historic and forecast data. This BoP applies only to projects closed during 2013-14.

The AER requires Energex to provide the following information relating to RIN Table 2.3.1 – Sub-Transmission Substations, Switching Station and Zone Substations:

- Substation ID
- Substation Type
- Project ID
- Project Type
- Project Trigger
- Voltage
- Substation Rating Normal Cyclic (MVA)
- Substation Rating Emergency Cyclic (MVA)

The AER requires Energex to provide the following information relating to RIN Table 2.3.2 – Sub-Transmission Lines:

- Line ID
- Project ID
- Project Type
- Project Trigger
- Voltage
- Route Line Length Added

These figures are part of Regulatory Template 2.3 – Augex.

Actual Information was provided for the following columns:

- Substation ID,
- Substation Type,
- Line ID,
- Project ID,
- Project Type,
- Project Trigger,
- Voltage,
- Substation Ratings* and
- Route Line Length Added*

Estimated Information was provided for Substation Ratings and Route Line Length Added where actual information is not available.

These variables are a part of Regulatory Template 2.3 – Augex

5.1 Consistency with Reset RIN Requirements

Table 5.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 5.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must include only projects and expenditure related to augmentation of the network.	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 – Augex – Subtransmission – Cost metrics for further information.
Unless otherwise indicated, 'Rating' or 'MVA added' refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables). As specified in the respective definitions of normal cyclic rating (for substations) and thermal rating (for lines and cables), Energex must provide its definition(s) of 'normal conditions' in the Basis of Preparation.	Please refer to sections 5.3.1 Assumptions and Section 5.4.1 Basis for Estimated Information.
Energex must not include information for gifted assets.	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 – Augex – Subtransmission – Cost metrics for further information.
Energex must enter related party and non related party contracts expenditures in the 'All related party contracts' and 'All non-related party contracts' columns, respectively. i. Expenditure figures inputted into the 'All related party contracts' and 'All non related party contracts' columns do not contribute to the column that calculates the total direct expenditure on an Augex project ('Total direct expenditure'). ii. Energex must record all contract expenditure for Augex projects under the 'All related party contracts' and 'All non related party contracts' columns. Energex must then allocate such contract expenditure to the appropriate 'Plant and equipment expenditure and volume' and 'Other expenditure columns. For example, if a non related party contract involves expenditure on civil works, Energex must record that expenditure under the 'All non related	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 – Augex – Subtransmission – Cost metrics for further information.

Requirements (instructions and definitions)	Consistency with requirements
party contracts' and 'Other expenditure – Civil works' columns.	
Energex must not include augmentation information relating to connections in this Regulatory Template.	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 – Augex – Subtransmission – Cost metrics for further information.
"For projects with a total cumulative expenditure over the life of the project of greater than or equal to $5 million (nominal):" For Table 2.3.1: (i) "insert a row for each augmentation project on a subtransmission substation, switching station and zone substation owned and operated by Energex where project close occurred at any time during the initial regulatory years; and" For Table 2.3.2 (ii) "insert a row for each augmentation project on a subtransmission line on Energex's network where project close occurred at any time during the initial regulatory years"	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 – Augex – Subtransmission – Cost metrics for further information.
For projects with a total cumulative expenditure over the life of the project less than $5 million (nominal) (non-material projects): For Table 2.3.1 (i) input the total expenditure for all non material augmentation projects on a subtransmission substation, switching station and zone substation owned and operated by Energex where project close occurred in the initial regulatory years in the penultimate row in the regulatory template, as indicated. For Table 2.3.2 (ii) input the total expenditure for all non material augmentation projects on subtransmission lines owned and operated by Energex where project close occurred in the initial regulatory years in the penultimate row in the regulatory template, as indicated	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 – Augex – Subtransmission – Cost metrics for further information.

Requirements (instructions and definitions)	Consistency with requirements
Unless otherwise indicated, 'Rating' or 'MVA added' refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables). As specified in the respective definitions of normal cyclic rating (for substations) and thermal rating (for lines and cables), Energex must provide its definition(s) of 'normal conditions' in the Basis of Preparation.	Please refer to sections 5.3.1 Assumptions and Section 5.4.1
For the avoidance of doubt, this includes augmentation works on any substation in Energex 's network, including those which are notionally operating at transmission voltages. In such cases, choose 'Other - specify' in the 'Substation type' category and describe the type of substation in the basis of preparation document(s).	Please refer to section 5.3.2 - Approach - Voltage
Each row must represent data for an augmentation project for an individual substation. i. If an augmentation project applies to two substations, for example, Energex must enter data for the two substations in two rows.	Data has been entered in accordance with instructions
Where a substation augmentation project in this table is related to other projects (including those in other tables in Regulatory Template 2.3), describe this relationship in the Basis of Preparation.	Please refer to Table 5.5: Substation Projects with Feeder Components
Where Energex chooses 'Other – specify' in a drop down list, it must provide details in the basis of preparation document(s).	Please refer to section 5.3.2 - Approach - project type
Where a subtransmission lines augmentation project in this table is related to other projects (including those in other tables in Regulatory Template 2.3), describe this relationship in the Basis of Preparation.	Please refer to Table 5.5: Substation Projects with Feeder Components
For 'Substation ID' and 'Project ID', input Energex's identifier for the substation and project, respectively. This may be the substation/project name, location and/or code.	Please refer to section 5.3.2 - Approach Substation ID and Project ID
For length metrics, 'km added' refers to the gross addition of the relevant length measure resulting from the augmentation work: (i) This must not be net of line or cable removal. If the augmentation project includes line or cable removal, describe the amount in Basis of Preparation.	Please refer to Table 5.7: Substation projects which have transformers removal components

Requirements (instructions and definitions)	Consistency with requirements
For 'Project trigger', choose the primary trigger for the project from the drop down list. Describe secondary triggers in the Basis of Preparation. Where there is no primary trigger (among multiple triggers), choose 'Other – specify' and describe the triggers in the Basis of Preparation.	Please refer to section 5.3.2 - Approach – Project triggers
For substation voltages, enter voltages in the format xx/xx, reflecting the primary and secondary voltages. For example, a transformer may have its voltage recorded as 500/275, where 500kV is the primary voltage and 275kV is the secondary voltage. i. Where a tertiary voltage is applicable, enter voltages in the format xx/xx/xx. For example, a transformer may have its voltage recorded as 220/110/33, where 220kV, 110kV and 33kV are the primary, secondary and tertiary voltages, respectively.	Data has been entered in accordance with instructions
For substation ratings, 'Pre' refers to the relevant characteristic prior to the augmentation work; 'Post' refers to the relevant characteristic after the augmentation work. Where a rating metric does not undergo any change, or where the project relates to the establishment of a new substation, input the metric only in the 'Post' column.	Data has been entered in accordance with instructions
Under 'Total expenditure' for transformers, switchgear, capacitors, and other plant items, include only the procurement costs of the equipment. This must not include installation costs.	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to BoP 2.3.2 – Augex – Subtransmission – Cost metrics for further information.
Expenditure inputted under the 'Land and easements' columns is mutually exclusive from expenditure that appears in the columns that sum to the 'Total direct expenditure' column. In other words, the 'Total direct expenditure' for a particular project must not include expenditure inputted into the 'Land and easements' columns.	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to section BoP 2.3.2 – Augex – Subtransmission – Cost metrics for further information.
If Energex records land and easement projects and/or expenditures as separate line items for regulatory purposes, select 'Other – specify' and note 'Land/easement expenditure' in the basis of preparation	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to section BoP 2.3.2 – Augex – Subtransmission – Cost

Requirements (instructions and definitions)	Consistency with requirements
document(s).	metrics for further information.
i. Energex must input expenditure directly attributable to the land purchase or easement compensation payments in the ‘Land purchases’ and ‘Easements’ columns, respectively. These costs include legal, stamp duties and cost of purchase or easement compensation payments.	Details around the development of the project list are covered in the Basis of Preparation for Augex expenditure figures. Please refer to section BoP 2.3.2 – Augex – Subtransmission – Cost metrics for further information.

5.2 Sources

As outlined in the Table 5.2 below, data was extracted from a number of primary sources:

Table 5.2: Information sources

Variable	Source
Project Type	Project Approval Report, Engineering Specification, Feasibility Study, Project Scope Statement
Project Trigger	Project Approval Report
Substation Rating	Project Approval Report, ERAT2, SIFT
Route Line Length Added	Engineering Specification, Feasibility Study, Project Scope Statement, GIS, Simulation Models(verification only)
Substation ID	SIFT, Project Approval Report
Substation Type	SIFT, ERAT2
Voltage	SIFT, ERAT2
Line ID	ERAT2, Project Approval Report

5.3 Methodology

5.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Normal conditions is described as the system state where all plant are configured in its intended operational state, without planned or forced outages on any plant item.
- Zone substations include 110/11 kV, 33/11 kV substations and 33 kV regulator stations.
- Sub-transmission feeders include 132 kV, 110 kV and 33 kV feeders.
- Pre-project rating information is based on plant rating methodologies at the time where the planning approval report was completed.
- Post-project rating information is based on current plant rating methodologies.
- All ratings are based on summer ratings
- All newly established zone substations would have no pre-project ratings.
- Feeder works within the boundary of the substation is not considered as part of RIN Table 2.3.2 for sub-transmission lines.
- Substation projects consist of feeder works less than 500m route are not considered as part of Table RIN 2.3.2 for sub-transmission lines.
- Regulators and switchgear installation works are define as part of substation works even if it does not contribute to an increase or decrease in substation capacity. These projects are included in RIN Table 2.3.1. A full list of projects that did not result in a change in capacity is shown in Table 5.6.
- The normal cyclic rating for a substation with an 11kV split bus configuration would be the sum of normal cyclic capacity of the number of transformers connected in that substation.
- If no past information is available, if two or more transformer of large varying sizes is connected in parallel, it is assumed that the smaller transformer are to be operated as hot standby to avoid any load sharing issues that would de-rate the substation.
- Feeders works documented are based on the construction voltage of the feeder
- Feeder re-conductoring works, conductor re-tensioning, pole upgrades, and feeder being re-energise to higher voltage levels is deemed to be classified as sub-transmission upgrade.

5.3.2 Approach

All information was sourced based on the AERs requirements. Figures were produced through manual review and cross referencing of sources identified above. The development of each variable is explained below.

Augex Project List

- The Augex project list was compiled in line with requirements set out in the Reset RIN. The development of the project lists is discussed in the Basis of Preparation for Augex expenditure figures.
- Only projects with total project expenditure greater than $5m were included in the detailed portion of RIN Table 2.3.1 and RIN Table 2.3.2.
- The following projects were identified as closed in 13/14 – all other projects in the template 2.5.1 and 2.5.2 are forecast:
  - C0065138
  - C0017124
  - C0061514
  - C0078163
  - C0117468
  - C0076327
  - C0065141
  - C0062104
  - C0076312
  - C0078162
  - C0076904
  - C0065166
  - C0095413
  - C0112414

Substation ID

- The details of which substation was augmented for each project was taken from either the planning approval report or SIFT. The Substation IDs provided are the three letter substation acronyms of the relevant substations.

Substation Type

- Zone Substations are classified as having a secondary voltage of 11 kV, this includes 33/11 kV, 110/11 kV and 132/11 kV substations. Bulk Supply Substations are classified as Sub-transmission Substations having a secondary voltage of

33 kV, this includes 110/33 kV and 132/33kV substations. Switching Stations are classified as substations where the substation does not transform voltage from one level to another.

- Based on the substation ID, the substation type was sourced from SIFT, where it classifies each substation to its substation type.

Project ID

- Energex project numbers generated by its enterprise system are used as the Project ID.

Line ID

- The Line ID is based on Energex feeder number acronyms. The ID reported is the current feeder number associated with the feeder where work was performed on. This however, may not be directly related to the feeder number that appeared on the project title and/or project scope. Note that feeder names can change as subsequent works are carried out.

- Based on the project, the line ID for each feeder that had works performed on is sourced from the planning approval report and cross referenced to the current feeder ID in ERAT2.

Voltage

- The voltage allocated under RIN Table 2.3.1 is based on the transformation voltage of the transformer. Hence, for a zone substation equipped with 110/11 kV transformers, the voltage would be entered as “110/11”. For a switching station, the rated voltage of the circuit breakers is used to determine the operating voltage of the switching station. Hence, for a 33 kV switchgear switching station site, the voltage would be entered as “33”.

- The voltage allocated under RIN Table 2.3.2 is based on the construction voltage of the feeders. The project approval report provides an indication of the construction voltage, and ERAT2 provides an indication of the current operating voltage.

- Table 5.3 below shows the voltage for feeders where “Other-Specify” is entered in RIN Table 2.3.2:

Table 5.3: Voltage for Sub-Transmission Feeders Table 2.3.2

Project ID	Voltage (kV)	Project ID	Voltage (kV)
C0065138	110	C0065141	33
C0061514	110	C0095413	33
C0078163	33	C0112414	33

Project Trigger

- Project trigger was identified from the project approval report under the section 'Limitations of the Existing Network' which gives a detailed description of the type of network limitations such as demand growth or voltage issue as well as including secondary drivers such as refurbishment or reliability improvement. It also provides further details such as the load forecast graph and network utilisation. Apart from that, 'Impact of Doing Nothing' in the PAR summarises all the network limitations not complying with the applied service standards if no work was done.

- The list of project with secondary drivers and their descriptions can be seen in Table 5.4 below.

Table 5.4: Projects with Secondary Drivers

Project ID	Additional Project Triggers
C0061514	Project also had a refurbishment driver.
C0117468	Project also had a refurbishment driver.
C0076327	Project also addressed voltage issue.
C0062104	Project also had a refurbishment driver.
C0078162	Project also addressed reliability issue.
C0065166	Project also had a refurbishment driver.

Project Type

- The 'Recommended Development' section of the Project Approval Report provides a high level scope of the project. The Project Scope Statement and Feasibility Study documents contain early drafts of the project scope. The Engineering Specification document produced by the design team contains the highest level of detail of the project scope. All of the documents above contain information that allows the determination of the Project Type.

- The Project Approval Report was the primary source in determining the project type. Other sources of information were also used where the Project Approval Report does not contain sufficient information, including Engineering Specification, Project Scope Statements and Feasibility Studies.

Route Line Length Added

- Route line length added for a feeder augmentation project was first obtained through the Engineering Specification under any ‘MAINS’ works, which included overhead feeders and underground cable work descriptions. When going through each project, important key words such as ‘feeder’, ‘mains’, ‘cable’ were searched through the whole document to ensure that no feeder works in the project was overlooked. The engineering specification however only reports the amount of cable/conductor length per core. The total route length would equally proportion based on a 3 core configuration and a single circuit (SCCT) or double circuit (DCCT) type arrangement. This provides a reference of how much conductor or cable was required for the augmentation.

- Other sources of information for the circuit/route length may include the ‘Scope of work’ in Project Scope Statement and Project Approval Report. The collated source of length data is then compared against Energex 33 kV SINCAL model, and the Energex corporate GIS systems.

- If the information differ between all sourced systems, the GIS model is used as the final result as it is based on corporate data for “as constructed” feeder works.

- If no documentation was available, the information would then be sourced from SIFT where the description of works for the feeder component is then compared against Energex 33kV SINCAL model, and Energex corporate GIS systems.

- There were instances where substation type projects consist of feeder augmentation works. These feeder components of these projects were also documented as a separate entry under RIN Table 2.3.2.

- Table 5.5 below shows substation projects which have feeder components entered in RIN Table 2.3.2:

Table 5.5: Substation Projects with Feeder Components

Project ID	Augmentation
C0065138	New DCCT UG
C0061514	New SCCT UG
C0078163	Line rebuild DCCT OH and new SCCT UG
C0065141	New DCCT UG

- The length metrics, ”km added” is based on the gross addition of the relevant length measured resulting from the augmentation works. Among the list of projects, there are projects which involve removal of line or cable to accommodate for the installation of the new circuit. These projects are identified in the table below.

Substation Rating

- Substation Rating can be identified from the Project Approval Report under section 'Limitations of the Existing Network' which gives a detailed description of the type of network limitations, this includes the Pre-Project Rating. The Post-Project Rating are obtained from the current corporate databases ERAT2 and SIFT.

- If the values differ between systems, SIFT substation ratings are used as the final result as it is based on current rating methodology and takes into account of the sharing capability between transformers to work out the true substation rating capability.

- Table 5.6 below details projects which are substation related projects that do not contribute to the increase in substation capacity.

Table 5.6: Substation Projects with no substation capacity increase

Project Number	Augmentation	Comments
C0065166	Replace 11kV switchgear	The new 11kV switchgear enables all of the transformers at the substation to be operated in parallel. This resulted in a decrease in substation normal cyclic rating due to mismatches of transformer ratings and impedances. The substation N-1 emergency rating increased due to an increase in circuit breaker rating.

- Table 5.7 below details projects where transformers were removed as part of the project scopes:

Table 5.7: Substation projects which have transformers removal components

Project Number	Transformers Removed
C0061514	Removed 3x5MVA 33/11kV transformers.
C0117468	Removed 3x12.5MVA 33/11kV transformers.
C0062104	Removed 2x12.5MVA 33/11kV transformers.

5.4 Estimated Information

5.4.1 Basis for Estimated Information

Substation Normal Cyclic and Emergency Cyclic Capacity

- The pre-project normal cyclic rating and pre-project emergency cyclic rating is sourced from previous planning approval reports. If there were no documentation of such, the transformer ratings are calculated based on Energex's current plant rating methodologies as per the Energex Plant Rating Manual. The factors applied to the nameplate of the old transformers are detailed in Table 5.8 below.

Table 5.8: Normal Cyclic & Emergency Rating Factors

Load Category	Normal Cyclic (NC) Factor	ONAN Emergency Cyclic (EC) Factor	ONAN Two Hour Emergency Cyclic (2HEC) factor	ONAF,OFDAN & OFDAF Emergency Cyclic (EC) Factor	ONAF,OFDAN & OFDAF Two Hour Emergency Cyclic (2HEC) factor
Domestic	1.2	1.35	1.45	1.25	1.35
Mix Pre-dominantly Domestic (MPD)	1.1	1.2	1.3	1.15	1.25
Mix Pre-dominantly Industrial (MPI)	1.1	1.2	1.3	1.15	1.25
Industrial	1.05	1.2	1.3	1.15	1.25
Continuous	1	1.2	1.2	1.15	1.15

Feeder Length

- With the available documentations, it was deemed complex to work out the length of feeder that was upgraded as part of a feeder augmentation project. This is due to the fact that feeder upgrade work consists of varying level of augmentation types to increase its rating capability. Therefore, a feeder upgrade project can consists of a combination of pole replacement, conductor replacement, conductor re-tensioning and 11 kV distribution overbuild.
- To reduce the complexity in obtaining this data, the full length of the upgraded feeder is used to populate the "circuit km upgraded" variable. Where more

information is available, all best endeavours were done to better reflect on the accuracy of the feeder length upgraded.

6 BoP 2.3.2 – Augex – Subtransmission – Cost metrics

RIN Table 2.3.1 and 2.3.2 include both historic and forecast data. This Basis of Preparation applies only to projects closed during 2013-14.

The AER requires Energex to provide the following information relating to RIN Table 2.3.1 - Augex Asset Data - Subtransmission Substations, Switching Stations And Zone Substations:

- Plant And Equipment Expenditure And Volume
- Other Expenditure
- Total Direct Expenditure
- Years Incurred
- All Related Party Contracts
- All Non Related Party Contracts
- Land And Easements

The AER requires Energex to provide the following information relating to RIN Table 2.3.2 - Augex Asset Data - Subtransmission Lines:

- Plant And Equipment Expenditure And Volume
- Other Expenditure
- Total Direct Expenditure
- Years Incurred
- All Related Party Contracts
- All Non Related Party Contracts
- Land And Easements

These variables are a part of Regulatory Template 2.3 – Augex.

The following items in RIN Table 2.3.1 are estimated:

- Transformers – Expenditure
- Switchgear – Expenditure
- Capacitors – Expenditure
- Other Plant Item – Expenditure
- Installation (Labour) – Volume and Expenditure
- Other Expenditure
- All Related Party Contracts
- All Non Related Party Contracts
- Land And Easements

All figures in RIN Table 2.3.2 are Estimated Information with the exception of "Years Incurred"

All remaining variables are Actual Information.

These variables are a part of Regulatory Template 2.3 – Augex

6.1 Consistency with Reset RIN Requirements

Table 6.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 6.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must include only projects and expenditure related to augmentation of the network.	Only projects under augmentation financial activity codes were reported.
Unless otherwise indicated, 'Rating' or 'MVA added' refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables). As specified in the respective definitions of normal cyclic rating (for substations) and thermal rating (for lines and cables), Energex must provide its definition(s) of 'normal conditions' in the basis of preparation document(s).	The calculations of capacity were based on normal conditions. For the definition of normal conditions please refer to BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics.
Energex must not include information for gifted assets.	No gifted assets were included.
Energex must not include augmentation information relating to connections in this Regulatory Template. Augmentations in relation to connections are to be inputted in the connections Regulatory Template (Regulatory Template 2.5).	No connection expenditure was included and it was stated in the connections Regulatory Template.
Energex must enter related party and non related party contracts expenditures in the 'All related party contracts' and 'All non related party contracts' columns, respectively. i. Expenditure figures inputted into the 'All related party contracts' and 'All non related party contracts' columns do not contribute to the column that calculates the total direct expenditure on an Augex project ('Total direct expenditure'). ii. Energex must record all contract expenditure for Augex projects under the 'All related party contracts' and 'All non related party contracts' columns. Energex must then allocate such contract expenditure to the appropriate 'Plant and equipment expenditure and volume' and 'Other expenditure columns. For example, if a non related party contract involves expenditure on civil works, Energex must record that expenditure under the 'All non related party contracts' and 'Other expenditure – Civil works' columns.	
"For projects with a total cumulative expenditure over the life of the	Only projects with greater

Requirements (instructions and definitions)	Consistency with requirements
project of greater than or equal to $5 million (nominal):" For Table 2.3.1: (iii) "insert a row for each augmentation project on a subtransmission substation, switching station and zone substation owned and operated by Energex where project close occurred at any time during the initial regulatory years; and" For Table 2.3.2 (iv) "insert a row for each augmentation project on a subtransmission line on Energex's network where project close occurred at any time during the initial regulatory years"	than $5 million nominal expenditure over the life of the project were reported separately.
For projects with a total cumulative expenditure over the life of the project less than $5 million (nominal) (non-material projects): For Table 2.3.1 (iii) input the total expenditure for all non material augmentation projects on a subtransmission substation, switching station and zone substation owned and operated by Energex where project close occurred in the initial regulatory years in the penultimate row in the regulatory template, as indicated. For Table 2.3.2 (iv) input the total expenditure for all non material augmentation projects on subtransmission lines owned and operated by Energex where project close occurred in the initial regulatory years in the penultimate row in the regulatory template, as indicated	Projects with less than $5 million nominal expenditure over the life of the project were consolidated into the expenditure figures in the penultimate row of each table.
Record all expenditure data on a project close basis in real dollars ($000s real June 2015) (including historical data). Energex must include data for augmentation works where project close occurs after the end date of forthcoming regulatory control period but incurs expenditure prior to this date. i. For future works, or works in progress, Energex must apply an expected year for project close. ii. DNSP must provide any calculations used to convert real to nominal dollars or nominal to real dollars for this purpose.	All project costs were stated in real dollars (June 2015) and were escalated using figures from the ABS.
For the avoidance of doubt, this includes augmentation works on any substation in Energex's network, including those which are notionally operating at transmission voltages. In such cases, choose 'Other - specify' in the 'Substation type' category and describe the type of substation in the basis of preparation document(s).	Details around the development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission -

Requirements (instructions and definitions)	Consistency with requirements
	Descriptor Metrics for further information
Each row must represent data for an augmentation project for an individual substation. i. If an augmentation project applies to two substations, for example, Energex must enter data for the two substations in two rows.	Data has been entered in accordance with instructions
Where a substation augmentation project in this table is related to other projects (including those in other tables in Regulatory Template 2.3), describe this relationship in the Basis of Preparation.	Details around the development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics for further information
Where Energex chooses 'Other – specify' in a drop down list, it must provide details in the basis of preparation document(s).	Details around the development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics for further information
Where a subtransmission lines augmentation project in this table is related to other projects (including those in other tables in Regulatory Template 2.3), describe this relationship in the Basis of Preparation.	Details around the development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics for further information
For 'Substation ID' and 'Project ID', input Energex's identifier for the substation and project, respectively. This may be the substation/project name, location and/or code.	Details around the development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics for further information
For length metrics, 'km added' refers to the gross addition of the relevant length measure resulting from the augmentation work: i. This must not be net of line or cable removal. If the augmentation project includes line or cable removal,	Details around the development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission -

Requirements (instructions and definitions)	Consistency with requirements
describe the amount in Basis of Preparation.	Descriptor Metrics for further information
For 'Project trigger', choose the primary trigger for the project from the drop down list. Describe secondary triggers in the Basis of Preparation. Where there is no primary trigger (among multiple triggers), choose 'Other – specify' and describe the triggers in the Basis of Preparation.	Details around the development of the project descriptions are covered in the BoP 2.3.1 – Augex – Subtransmission - Descriptor Metrics for further information
For substation voltages, enter voltages in the format xx/xx, reflecting the primary and secondary voltages. For example, a transformer may have its voltage recorded as 500/275, where 500kV is the primary voltage and 275kV is the secondary voltage. i. Where a tertiary voltage is applicable, enter voltages in the format xx/xx/xx. For example, a transformer may have its voltage recorded as 220/110/33, where 220kV, 110kV and 33kV are the primary, secondary and tertiary voltages, respectively.	Data has been entered in accordance with instructions
For substation ratings, 'Pre' refers to the relevant characteristic prior to the augmentation work; 'Post' refers to the relevant characteristic after the augmentation work. Where a rating metric does not undergo any change, or where the project relates to the establishment of a new substation, input the metric only in the 'Post' column.	Data has been entered in accordance with instructions
Under 'Total expenditure' for transformers, switchgear, capacitors, and other plant items, include only the procurement costs of the equipment. This must not include installation costs.	Installation costs were reported separately in each table.
Expenditure inputted under the 'Land and easements' columns is mutually exclusive from expenditure that appears in the columns that sum to the 'Total direct expenditure' column. In other words, the 'Total direct expenditure' for a particular project must not include expenditure inputted into the 'Land and easements' columns.	Total direct expenditure does not include any expenditure for land or easements.
If Energex records land and easement projects and/or expenditures as separate line items for regulatory purposes, select 'Other – specify' and note 'Land/easement expenditure' in the basis of preparation document(s).	No Land and easement projects greater than $5m were included in 2013-14
i. Energex must input expenditure directly attributable to the land purchase or easement compensation payments in the 'Land purchases' and 'Easements' columns, respectively. These costs include legal, stamp duties and cost of purchase	Data has been entered in accordance with instructions

Requirements (instructions and definitions)	Consistency with requirements
or easement compensation payments.	

The following items in Table 2.3.1 were estimated:

- Transformers – Expenditure;
- Switchgear – Expenditure;
- Capacitors – Expenditure;
- Other Plant Item – Expenditure;
- Installation (Labour) – Volume and Expenditure;
- Other Expenditure;
- All Related Party Contracts;
- All Non Related Party Contracts; and
- Land and Easements.

All figures in RIN Table 2.3.2 are Estimated Information with the exception of “Years Incurred”.

All remaining variables are Actual Information.

6.2 Sources

Table 6.2 below sets out the sources from which Energex obtained the required information.

Table 6.2: Information sources

Variable	Source
All variables	EPM, P6 Project Management System

Supporting information included additional project information from the P6 project management system.

6.3 Methodology

All figures for RIN Tables 2.3.1 and 2.3.2 were calculated by firstly defining the Energex projects that related to subtransmission Augex. Each of these projects was then classified as either material or non-material. The transactions against each material project were then analysed to report against the required categories in RIN Tables 2.3.1 and 2.3.2.

6.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Total cumulative expenditure of a project includes overhead costs as per AER clarification;
- Subtransmission lines projects greater than $5m must include a material amount of subtransmission lines works, for further details please refer to the “Project Description and Changes” Basis of Preparation;
- In RIN Table 2.3.1 “other plant items” include subtransmission line materials detailed in RIN Table 2.3.2;
- In RIN Table 2.3.2 “other plant items” include zone and bulk supply material costs included in Table 2.3.1;
- Installation labour in RIN Table 2.3.1 includes “cable installation” labour;
- Installation labour was allocated based on work group;
- Installation volume in RIN Table 2.3.1 is the sum of the substation assets installed;
- Installation volume in RIN Table 2.3.2 is the sum of the circuit length installed.
- Design and construct contracts were spread over installation labour, civil works and other direct costs;
- Nominal costs were escalated based on CPI from the ABS;
- Cost components of project were escalated based on a single escalation value calculated for each project;
- Number of poles upgraded is dependent on the driver of the project;
- Related party margins are zero; and
- For strategic land purchased the project type and project trigger were listed as “Other Specify”.

6.3.2 Approach

Project List Development

1) A report was run from EPM Business Objects which listed all projects closed within the regulatory year 2013/14 under the Augex financial activity codes in Table 6.3 over page:

Table 6.3: Augex financial activity codes for projects closed in 2013/14

Activity Code	Description
C2020	CWT Demand Driven Primary
C2030	CWT Reliability Imp Primary
C2050	CWT Demand Prim Reliability Sec
C2060	CWT Demand Prim Refurb Sec
C2070	CWT Land & Right of Way
C2075	CWT Easements
C2080	CWT Community Requirements

This report included all Energex projects, not only those related to subtransmission. As such, the project list was filtered to include only those relating to subtransmission by analysing the project descriptions and budget codes.

2) The extracted subtransmission project list reported each project and their total yearly expenditure broken down by direct costs and overheads as per the Energex CAM. Each project with a total (whole of life) expenditure of greater than $5 million (nominal, inclusive of direct and overhead costs) was reported as a separate project in the Regulatory Template. Those projects less than $5 million were labelled as a non-material project to be consolidated into a single substation line item in RIN Table 2.3.1 and a single subtransmission line item in RIN Table 2.3.2.

3) Each project was then required to be labelled as either a substation project (for input into RIN Table 2.3.1), a subtransmission lines project (for input into RIN Table 2.3.2); some projects appear in both tables. Material projects were allocated to the respective tables based on detailed analysis of the project documentation. This allocation is based on assumptions that are documented in the “Augex – Project Description and Changes” Basis of Preparation (please note that a material project could be reported within both tables if it incorporated both substation and lines construction). Immaterial projects were allocated to either RIN Table 2.3.1 or 2.3.2 based on analysis of the project descriptions.

4) This then gave the list of subtransmission projects to be reported.

Expenditure and Volume Values

1) The total direct cost for each project reported in RIN Tables 2.3.1 and 2.3.2 was then calculated using the yearly costs for each project extracted in the EPM report stated above. These yearly costs were multiplied by an escalation factor to convert the figures to $2014-15. The escalation factors were calculated from the ABS values for CPI based on the eight capital city average and are found in Table 6.4 over page:

Table 6.4: Escalation factors

Financial Year	Escalation Factor
2002 FY	1.419
2003 FY	1.389
2004 FY	1.344
2005 FY	1.310
2006 FY	1.281
2007 FY	1.244
2008 FY	1.215
2009 FY	1.165
2010 FY	1.137
2011 FY	1.105
2012 FY	1.069
2013 FY	1.052
2014 FY	1.029
2015 FY	1.000

2) To calculate the remaining columns in RIN Tables 2.3.1 and 2.3.2 a second report was run from EPM which detailed all expenses and quantities against each of the projects. A detailed analysis was then done on each of the project expenses and quantities to determine how they were grouped into the categories required in each table. Each expense was grouped into an intermediate category and then grouped into the categories required in the tables (an intermediate category was required due to the number of transactions that had to be categorised and also to be able to calculate the quantities required in the tables).

3) An analysis was firstly done on the materials costs against each project. Each materials expense is classified by a Stock Item Group Class (SIGC). The following SIGCs were identified as being both high value and applicable to the material breakup required in RIN Tables 2.3.1 and 2.3.2:

   a. CABLE, ELECTRICAL
   b. CAPACITORS
   c. CIRCUIT BREAKERS
   d. COILS AND TRANSFORMERS
   e. CONNECTORS, ELECTRICAL
   f. ELECTRIC HARDWARE
   g. ELECTRICAL CONTROL EQUIP
   h. ELECTRICAL TEST
   i. FIXTURES AND LIGHTING

j. FUSES
k. INSULATORS
l. MISC ELECTRIC POWER
m. MISC ELECTRICAL COMPONENT
n. PREFAB TOWER STRUCTURES
o. RELAYS AND SOLENOIDS
p. SWITCHES
q. WOOD POLES

4) Each stock item within these SIGCs was then analysed individually to assign them to one of the following intermediate classifications:

   a. Cable - Overhead
   b. Cable - Overhead LV
   c. Cable - Overhead Transmission
   d. Cable - Underground Transmission
   e. Capacitor 15 MVAR
   f. Capacitor 20 MVAR
   g. Capacitor 3.6 MVAR
   h. Capacitor 5.4 MVAR
   i. Capacitor 62.5 MVAR
   j. Materials - Other
   k. Pole
   l. Pole-SL
   m. Switchgear
   n. Transformer - Distribution
   o. Tx Pwr 120 MVA
   p. Tx Pwr 15 MVA
   q. Tx Pwr 25 MVA
   r. Tx Pwr 30 MVA
   s. Tx Pwr 60 MVA
   t. Tx Pwr 8 MVA
   u. Tx Pwr 80 MVA

5) Once the materials costs had been classified using the stock item descriptions, the remaining expenses against each project were classified using various information assigned to each expense item. Table 6.5 outlines the logic applied to group these expenses into their intermediate expense categories.

Table 6.5: Logic applied to group expenses

Energex Intermediate Category	Logic Applied
Civil	• The text ‘civil’ appears in the purchase order or invoice descriptions • The workgroup on the work order ended with ‘CV’ which indicates a civil workgroup • The text ‘civil’ appears in the work order description • The text ‘pit’ appears in the work order description
Energex Labour-Instal	• Cost Category Type is ‘Labour’ • The work order maintenance type is Construction, Costing Work Order, Equipment Replacement, Pole Recovery, Recover Asset/Equipment, Repair Non-Storm, Replace pole, Switching Work Order, Testing/Commissioning, Vegetation Management
Energex Labour-Non Instal	All Other Energex Labour costs
IOB	Account Elements 8570 & 8580
Cable Installation	• Cost Category Type is “Contractor’ • Work Order Description contains ‘UG Constr’ • The following contractors: – BAYLISS CONSTRUCTIONS PL – DIONA PL – INFRASTRUCTURE CONSTRUCTIONS PL – JEMENA ASSET MANAGEMENT PL – OZCAT CONTRACTING PL – THIESS SERVICES PL
Ctr-D&C	• The texts ‘design’ and ‘construct’’ appear in the purchase order or invoice descriptions
Ctr-Instal	• The cost category type is ‘Contractor’ • The work order maintenance type is Construction, Costing Work Order, Equipment Replacement, Manufacture, Pole Recovery, Purchase Asset, Purchase to Pay, Recover Asset/Equipment, Replace pole, Switching Work Order, Testing/Commissioning, Vegetation Management
Ctr-Non-Instal	• All other Contractor Expenses not classified in any of the above processes

Energex Intermediate Category	Logic Applied
Ctr-Other-DE-WOType	• The work order maintenance type is 'Design' and the cost category type is 'Contractor'
Ctr-Sparq	• Account Element 4940
Easements	• Account Element 3120
Land	• Top Project: Financial Activity Code is C2070 and Account Element is 5405 • Top Project: Financial Activity Code is C2070 and Account Element is 5330 • Top Project: Financial Activity Code is C2070 and a manual review of costs indicates land purchase
Switchgear (DirectMtrls)	• Supplier is Ergon Energy • Supplier is Mitsubishi Electric Australia
Materials-Direct	• Direct Purchase Material costs not classified in any of the above processes
Materials-Stores	• Stock Item Material Stores Issues not classified in any of the above processes
Other	• Cost Category INTERNAL LABOUR - OTHER COSTS • Account Element 4425 • All other residual costs

Once all costs had been categorised into intermediate categories they were then grouped into those required in RIN Tables 2.3.1 and 2.3.2. Table 6.6 outlines the grouping of intermediate categories for RIN Table 2.3.1.

Table 6.6: Grouping of Intermediate categories for RIN table 2.3.1

CA RIN Category – Table 2.3.1	Energex Intermediate Categories
Transformers Units Added	Quantity values within: • Tx Pwr 120 MVA • Tx Pwr 15 MVA • Tx Pwr 25 MVA • Tx Pwr 30 MVA • Tx Pwr 60 MVA • Tx Pwr 8 MVA • Tx Pwr 80 MVA

CA RIN Category – Table 2.3.1	Energex Intermediate Categories
Transformers MVA Added	The quantity multiplied by the rating within: • Tx Pwr 120 MVA • Tx Pwr 15 MVA • Tx Pwr 25 MVA • Tx Pwr 30 MVA • Tx Pwr 60 MVA • Tx Pwr 8 MVA • Tx Pwr 80 MVA
Transformers	Expenses within: • Tx Pwr 120 MVA • Tx Pwr 15 MVA • Tx Pwr 25 MVA • Tx Pwr 30 MVA • Tx Pwr 60 MVA • Tx Pwr 8 MVA • Tx Pwr 80 MVA
Switchgear Units Added	Quantity values within: • Switchgear (DirectMtrls)
Switchgear	Expenses within: • Switchgear (DirectMtrls)
Capacitors Units Added	Quantity values within: • Capacitor 15 MVAR • Capacitor 20 MVAR • Capacitor 3.6 MVAR • Capacitor 5.4 MVAR • Capacitor 62.5 MVAR
Capacitors MVAR Added	The quantity multiplied by the rating within: • Capacitor 15 MVAR • Capacitor 20 MVAR • Capacitor 3.6 MVAR

CA RIN Category – Table 2.3.1	Energex Intermediate Categories
	• Capacitor 5.4 MVAR • Capacitor 62.5 MVAR
Capacitors	Expenses within: • Capacitor 15 MVAR • Capacitor 20 MVAR • Capacitor 3.6 MVAR • Capacitor 5.4 MVAR • Capacitor 62.5 MVAR
Other Plant Item	Expenses within: • Materials-Direct • Materials-Stores • Cable - Overhead • Cable - Overhead LV • Cable - Overhead Transmission • Cable - Underground Transmission • Pole • Pole-SL • Transformer - Distribution • Materials - Other
Installation Labour - Volume	Installation labour spend divided by average cost per hour of Energex Labour-Install.
Installation Labour	Expenses within: • Energex Labour-Install • Cable Installation • Ctr-Install • Ctr-D&C (33%)
Civil Works	Expenses within: • Civil • Ctr-D&C (33%)
Other Direct	Expenses within: • Energex Labour-Non Install

CA RIN Category – Table 2.3.1	Energex Intermediate Categories
	• Ctr-Non-Install • Ctr-Other-DE-WOType • Ctr-D&C (33%) • Ctr-Sparq • Other • IOB
Total Direct Expenditure	As per RIN Template
Related Party Margins	NA
Related Party Total	Expenses within: • Ctr-Sparq
All Non Related Party Contracts	Expenses within: • Civil • Cable Installation • Ctr-Install • Ctr-Non-Install • Ctr-Other-DE-WOType • Ctr-D&C
Land Purchase	Expenses within: • Land
Easements	Expenses within: • Easements

Table 6.7 below outlines the grouping of intermediate categories for RIN Table 2.3.2.

Table 6.7: Grouping of Intermediate categories for table 2.3.1

CA RIN Category – Table 2.3.2	Energex Intermediate Categories
Poles / Towers Added	Quantity values within: • Pole Poles are allocated as either added or upgraded based on the main driver of the project
Poles / Towers Upgraded	
Poles/Towers Expenditure	Expenses within:

CA RIN Category – Table 2.3.2	Energex Intermediate Categories
	• Pole
Overhead Lines Expenditure	Expenses within: • Cable overhead transmission
Underground Cables Expenditure	Expenses within: • Cable underground transmission
Other Plant Item Expenditure	Expenses within: • Switchgear • Materials direct • Materials stores • Materials other • Power Transformers • Capacitor banks • Pole SL
Installation Labour - Volume	Installation labour spend divided by average cost per hour of Energex Labour-Install
Installation Labour	Expenses within: • Energex Labour-Install • Cable Installation • Ctr-Install • Ctr-D&C (33%)
Civil Works	Expenses within: • Civil • Ctr-D&C (33%)
Other Direct	Expenses within: • Energex Labour-Non Install • Ctr-Non-Install • Ctr-Other-DE-WOType • Ctr-D&C (33%) • Ctr-Sparq

CA RIN Category – Table 2.3.2	Energex Intermediate Categories
	• Other • IOB
Total Direct Expenditure	Calculated as per RIN Regulatory Template
Related Party Margins	NA
Total	As per RIN Regulatory Template.
All Non Related Party Contracts	Expenses within: • Civil • Cable Installation • Ctr-Install • Ctr-Non-Install • Ctr-Other-DE-WOType • Ctr-D&C
Land Purchase	Expenses within: • Land
Easements	Expenses within: • Easements

6.4 Estimated Information

The following figures in RIN Table 2.3.1 were estimated:

- Transformers – Expenditure
- Switchgear – Expenditure
- Capacitors – Expenditure
- Other Plant Item – Expenditure
- Installation (Labour) – Volume and Expenditure
- Other Expenditure
- All Related Party Contracts

- All Non Related Party Contracts
- Land and Easements

The following figures in RIN table 2.3.2. were estimated:

- Poles/Towers (including structures, and civil works) – Expenditure
- Overhead lines – Expenditure
- Underground cables – Expenditure
- Other plant items – Expenditure
- Installation (Labour) – Volumes and Expenditure
- Civil Works – Expenditure
- Other Direct – Expenditure
- All Related Party Contracts
- All Non Related Party Contracts
- Land and Easements

All the items above are Estimated Information due to the judgements that were made during the categorisation of expenses and quantities.

6.4.1 Justification for Estimated Information

Energex does not capture costs or quantities in the categories required in RIN Tables 2.3.1 and 2.3.2. As such was required to manually categorise each into the categories required.

6.4.2 Basis for Estimated Information

Each cost and quantity was manually categorised using multiple descriptors within the data. For full details please refer to the approach section above.

7 BoP 2.3.3 – Augex – Distribution

The AER requires Energex to provide the following information relating to RIN Table 2.3.3.1 – Augex Data – HV/LV Feeders And Distribution Substations – Descriptor Metrics:

- **HV Feeder Augmentations - Overhead Lines (Circuit Line Length Km)**
- **HV Feeder Augmentations - Underground Cables (Circuit Line Length Km)**
- **LV Feeder Augmentations - Overhead Lines (Circuit Line Length Km)**
- **LV Feeder Augmentations - Underground Cables (Circuit Line Length Km)**
- **Distribution Substation Augmentations - Pole Mounted**
- **Distribution Substation Augmentations - Ground Mounted**
- **Distribution Substation Augmentations – Indoor**

The AER requires Energex to provide the following information relating to RIN Table 2.3.3.2 – Augex Data – HV/LV Feeders And Distribution Substations – Cost Metrics:

- **HV Feeder Augmentations - Overhead Lines ($000's)**
- **HV Feeder Augmentations - Underground Cables ($000's)**
- **HV Feeder Non-Material Projects ($000's)**
- **LV Feeder Augmentations - Overhead Lines ($000's)**
- **LV Feeder Augmentations - Underground Cables ($000's)**
- **LV Feeder Non-Material Projects ($000's)**
- **Distribution Substation Augmentations - Pole Mounted ($000's)**
- **Distribution Substation Augmentations - Ground Mounted ($000's)**
- **Distribution Substation Augmentations - Indoor ($000's)**

All data is Estimated Information.

These variables are a part of Regulatory Template 2.3 – Augex.

7.1 Consistency with Reset RIN Requirements

Table 7.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 7.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must include only projects and expenditure related to augmentation of the network.	Only projects under augmentation financial activity codes were reported.
Unless otherwise indicated, 'Rating' or ‘MVA added’ refers to equipment's normal cyclic rating (for substations) or thermal rating (for lines and cables).	The calculations of capacity were based on normal conditions. For the definition of normal conditions please refer to Basis of Preparation 2.3.1.

Requirements (instructions and definitions)	Consistency with requirements
Energex must not include information for gifted assets.	No gifted assets were included.
Energex must not include augmentation information relating to connections in this Regulatory Template. Augmentations in relation to connections are to be inputted in the connections Regulatory Template (Regulatory Template 2.5).	No connection expenditure was included and it was stated in the connections Regulatory Template.
For Table 2.3.3.1 – "Complete the table by inputting the required details for: i) the rows that summarise all augmentation works on the specified types of HV feeders owned and operated by Energex undertaken at any time during the years specified for projects with a total cumulative expenditure over the life of the project of greater than or equal to $0.5 million (nominal); and ii) the row that summarises all augmentation works on HV feeders owned and operated by Energex undertaken at any time during the years specified for projects with a total cumulative expenditure over the life of the project of less than $0.5 million (nominal)"	HV feeder projects with greater than $0.5 million nominal expenditure over the life of the project were reported separately. Those with less than $0.5 million were input in the summary row.
For Table 2.3.3.2 – "Complete the table by inputting the required details for: i) the rows that summarise all augmentation works on the specified types of LV feeders owned and operated by Energex undertaken at any time during the years specified for projects with a total cumulative expenditure over the life of the project of greater than or equal to $50,000 (nominal); and ii) the row that summarises all augmentation works on LV feeders owned and operated by Energex undertaken at any time during the years specified for projects with a total cumulative expenditure over the life of the project of less than $50,000 (nominal).	HV feeder projects with greater than $50,000 nominal expenditure over the life of the project were reported separately. Those with less than $50,000 were input in the summary row.
Record all expenditure data on an 'as incurred' basis in nominal dollars.	All project costs were stated in nominal dollars in the year incurred.
For projects that span across regulatory years, input figures for the 'Circuit km added' and 'Circuit km upgraded' columns according to the final year in which expenditure was incurred for the project.	Circuit km added and upgraded were only counted on projects completed in 2014-15
Energex must not include expenditure related to land	Expenditure figures do not include any expenditure for land or

Requirements (instructions and definitions)	Consistency with requirements
purchases and easements in the 'Total direct expenditure' column. Land purchases and easements expenditure related to augmentation works on all LV feeders owned and operated by Energex must be inputted in Table 2.3.6.	easements.

Estimated Information was provided for all figures.

7.2 Sources

Table 7.2 below sets out the sources from which Energex obtained the required information.

Table 7.2: Information sources

Variable	Source
All variables	EPM

7.3 Methodology

All figures for RIN Table 2.3.3 were calculated by firstly defining the Energex projects that related to distribution Augex. Each of these projects was then classified as either HV, LV or Distribution Substation and the quantity and expenditure against each project reported in the respective categories. Lastly the distribution components of any projects identified in RIN Tables 2.3.1 and 2.3.2 as subtransmission projects was added to the figures.

7.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Overhead open wire conductor can be used at any voltage. Overhead conductor with an unspecified voltage was assumed to be HV rather than LV;
- If projects were unable to be assigned to an asset class they were assigned to HV feeders.

7.3.2 Approach

Project List Development

1) A report was run from EPM Business Objects which listed all projects with transactions within regulatory years 2009 – 2014 under the Augex financial activity codes in Table 7.3 over page:

Table 7.3: Augex Financial Activity Codes for Project Transactions 2009 -2014

Activity Code	Description
C2020	CWT Demand Driven Primary
C2030	CWT Reliability Imp Primary
C2050	CWT Demand Prim Reliability Sec
C2060	CWT Demand Prim Refurbishment Sec
C2070	CWT Land & Right of Way
C2075	CWT Easements
C2080	CWT Community Requirements
C2090	CWT Eng & Admin
C2095	CWT Infrastructure Projects
C2565	CWDA Co Initiated
C2580	CWDA Control & Metering

2) This report included all Energex projects, not only those related to HV feeders, LV feeder and distribution transformers. As such, the project list was filtered to include only those relating to relevant assets by analysing the project descriptions and budget codes.

3) The extracted project list reported each project and their total yearly expenditure broken down by direct costs and overheads as per the Energex CAM.

Project Allocation

4) Each project was then required to be labelled as either a HV feeder, LV feeder or distribution transformer project. This was a complex task as projects rarely include only one asset class. Each project was required to be categorised as different cost thresholds exist for each asset class.

5) For existing projects that had already been allocated as part of the CA RIN (2008/09 to 2012/13) the existing categorisations were taken. In order to allocate

the new projects for 2013/14 a second report was run from EPM that detailed all expenses and quantities against each of the projects. A detailed analysis was then done on each of the project expenses and quantities to extract overhead cable and underground cable, pole and distribution transformer material booked to the projects.

6) Each stock item was then analysed individually to assign them to one of the following intermediate classifications:

   a. Cable – Overhead;
   b. Cable - Overhead LV;
   c. Cable - Overhead Transmission;
   d. Cable - Underground LV;
   e. Cable - Underground HV;
   f. Cable - Underground Transmission;
   g. Materials – Other;
   h. Pole;
   i. Switchgear;
   j. Pole mounted transformer;
   k. Pad mounted transformer;
   l. Ground mounted transformer; and
   m. Power transformer.

7) Once the material for each project was known the projects were allocated using an iterative logic approach.

   a. The first pass was based on the material expenditure.
   b. Where material expenditure was greater than 10% of the project cost and greater than $500 the material was used to separate feeder projects from transformer projects.
   c. If a project had greater than 75% transformer materials it was categorised as a transformer project.
   d. If a project had greater than 75% feeder materials it was categorised as a feeder project. Of these projects, if the majority of expenditure was LV the project was classified as a LV feeder project, else it was categorised as a HV feeder project.
   e. The next step was to categorise the project based on a keyword search of the project title. Some of the keywords used are shown below:

HV Feeders	LV Feeders	Distribution Transformers
11 kV tie	LV Prot	MDI (Max Demand

11 up upHV	Up LV Aug LV	Indicator) UpTx Tx

f. The next step was to use the highest cost element to determine the project.

8) Once all projects had been categorised as a HV feeder, LV feeder or distribution transformer, cost thresholds were applied to determine which projects would need to be reported as in Table 2.3.3 of the RIN. The cost thresholds were $500k for HV feeder projects, $50k for LV feeder projects and $0 for distribution transformer projects.

9) The projects were then categorised as either overhead or underground for feeders and by transformer type for distribution transformers. The allocation was based on the highest cost element in the project.

10) The last assessment was whether the augmentation was an upgrade of an existing asset or an addition to the network. This was again based on keywords within the project description coupled with review of project documentation.

Annual expenditure was reported as the summation of projects within each of the categories.

These steps were undertaken for all projects that were distribution driven projects.

Subtransmission primary projects

- The AER requires distribution components of subtransmission projects to also be reported in RIN Table 2.3.3. This clarification by the AER required the distribution costs of a project to be separated from the main project (such as a new zone substation). The projects were allocated to the asset class using the same method detailed above with the additional step of estimating the distribution component of the project.

- The distribution component of a subtransmission project was estimated based on the material cost of the distribution assets, e.g. if 5% of the material cost was used for distribution assets 5% of the as incurred expenditure associated with the project will be included as distribution expenditure. This proportioning also applied to the reporting thresholds.

7.4 Estimated Information

All data is Estimated Information due to the judgements that were made during the categorisation of expenses and quantities.

7.4.1 Justification for Estimated Information

Energex does not capture costs or quantities in the categories required in RIN Tables 2.3.3. As such was required to manually categorise each into the categories required.

7.4.2 Basis for Estimated Information

Each cost and quantity was manually categorised using multiple descriptors within the data. For full details please refer to the approach section above.

7.5 Explanatory notes

In most projects multiple types of assets will be installed as part of the project, however the reporting by asset class only includes the specific type of asset install as part of the project, e.g. if a HV feeder project includes the installation of a pole mounted transformer, only the HV feeder asset is reported in RIN Table 2.3.3.

8 BoP 2.3.4 – Augex – Summary Table

The AER requires Energex to provide the following information relating to RIN Table 2.3.4:

- **Subtransmission substations, switching stations, zone substations**
- **Subtransmission lines**
- **HV feeders**
- **HV feeders – land Purchase and easements**
- **Distribution substations**
- **Distribution substation – land purchase and easements**
- **LV Feeders**
- **LV Feeder – land purchase and easements**

These variables are a part of Regulatory Template 2.3 – Augex.

All data is Estimated Information.

8.1 Consistency with Reset RIN Requirements

Table 8.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 8.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must include only projects and expenditure related to augmentation of the network.	Only projects under augmentation financial activity codes were reported.
Energex must not include information for gifted assets.	No gifted assets were included.
Energex must not include augmentation information relating to connections in this Regulatory Template. Augmentations in relation to connections are to be inputted in the connections Regulatory Template (Regulatory Template 2.5).	No connection expenditure was included and it was stated in the Connections Regulatory Template.
Record all expenditure data on an 'as incurred' basis in nominal dollars.	Expenditure is nominal as incurred.
Energex must explain how the sum of the asset group augmentation expenditures reconciles to the augmentation expenditure in Tables 2.3.1 to 2.3.5	Refer to Explanatory Notes

Requirements (instructions and definitions)	Consistency with requirements
Expenditure inputted under the ‘Land and easements’ rows are mutually exclusive from expenditure that appear in the rows for the corresponding asset group. For example, Augex attributed to HV feeders must not include expenditure related to ‘HV feeders – land purchases and easements’.	‘Land and easements’ rows were mutually exclusive.

Estimated Information was provided for all figures.

8.2 Sources

Table 8.2 below sets out the sources from which Energex obtained the required information.

Table 8.2: Information sources

Variable	Source
All variables	EPM*

* EPM is an Enterprise Data Warehouse (EDW). It takes data from across the organisation overnight, every night, filters it against the agreed business principles and then stores it. Business users can then access the information through the 'visualisation suite of tools' and be confident that the information they obtain is from a single source of the truth for performance information.

8.3 Methodology

All figures for RIN Table 2.3.4 were calculated based on the data generated to populate RIN Tables 2.3.1 to Table 2.3.5. The population of Table 2.3.4 was completed by filtering the list of projects with expenditure recorded in the period into the required project classifications.

8.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Overhead open wire conductor can be used at any voltage. Overhead conductor with an unspecified voltage was assumed to be HV rather than LV.
- If projects were unable to be assigned to an asset class they were assigned to HV feeders.
- Subtransmission projects not reviewed in detail for Table 2.3.1 or 2.3.2 were assumed to be either substation or lines projects based on the project description.

- Where projects have a significant combination of Subtransmission and distribution works as incurred expenditure is apportioned based on the relative material costs of Subtransmission assets and distribution assets issued during the period.

- Strategic land and easement purchases were included as Other Assets in Table 2.3.4.

8.3.2 Approach

Project List Development

- A report was run from EPM Business Objects which listed all projects with transactions within the regulatory years 2009 – 2014 under the Augex financial activity codes below:

Activity Code	Description
C2020	CWT Demand Driven Primary
C2030	CWT Reliability Imp Primary
C2050	CWT Demand Prim Reliability Sec
C2060	CWT Demand Prim Refurbishment Sec
C2070	CWT Land & Right of Way
C2075	CWT Easements
C2080	CWT Community Requirements
C2090	CWT Eng & Admin
C2095	CWT Infrastructure Projects
C2565	CWDA Co Initiated
C2580	CWDA Control & Metering

- This report included all Energex projects.

- The extracted project list reported each project and their total yearly expenditure broken down by direct costs and overheads as per the Energex CAM.

Project Allocation

- Each project was required to be labelled as either a HV feeder, LV feeder or distribution transformer project. This was a complex task as projects rarely include only one asset class. Each project was required to be categorised as different cost thresholds exist for each asset class.
- This step is detailed in Basis of Preparation 2.3.3 for classification of HV feeder, LV feeder and distribution transformer projects.
- Sub-transmission projects were detailed in Basis of Preparation 2.3.1 Augex.

Data Extraction

The following rules were applied to the dataset to extract expenditure associated with each of the project types:

Sub-transmission substations, switching stations, zone substations

- Sum of Proportioned Sub-transmission expenditure where Subtransmission Project type = TCAP – Sub.

Sub-transmission lines

- Sum of Proportioned Sub-transmission expenditure where Project type = TCAP – Line.

HV feeders

- Sum of Proportioned distribution expenditure where Project type = HV Feeder.
- Less land purchased and easements in the year.

HV feeders – land Purchase and easements

- Sum of proportioned distribution land and easement expenditure where Project type = HV Feeder.

Distribution substations

- Sum of Proportioned distribution expenditure where Project type = Dist Tx.
- Less land purchased and easements in the year.

Distribution substation – land purchase and easements

- Sum of proportioned distribution land and easement expenditure where Project type = Dist Tx .

LV Feeders

- Sum of Proportioned distribution expenditure where Project type = LV Feeder.
- Less land purchased and easements in the year.

LV Feeders – land purchase and easements

- Sum of proportioned distribution land and easement expenditure where Project type = LV Feeder.

Other Assets

- Sum of Proportioned Sub-transmission expenditure where Project type = Land easements.

8.4 Estimated Information

All data is Estimated Information due to the judgements that were made during the categorisation of expenses and quantities.

8.4.1 Justification for Estimated Information

- Energex does not capture costs or quantities in the categories required in RIN Tables 2.3.4. As such, Energex was required to manually categorise each into the categories required.
- The timing of land and easement expenditure was not captured in the data extract. For consistency, land and easement expenditure was recorded in the final year of expenditure, similar to asset volumes in RIN Table 2.3.3.1. Land and easement expenditure is less than 1 percent of distribution Augex expenditure.

8.4.2 Basis for Estimated Information

Each cost and quantity was manually categorised using multiple descriptors within the data. For full details, please refer to the approach section above.

8.5 Explanatory notes

Energex is required to explain how the sum of the asset group expenditure reconciles with data in Tables 2.3.1 to 2.3.5. The AER gave further guidance through the CA RIN Issues Register:

> *The explanation should include a general description of the link between Tables 2.3.1 to 2.3.3 and Table 2.3.4, including any assumptions and calculations utilised in the relationships between Tables 2.3.1 to 2.3.3 and Table 2.3.4. Tables 2.3.1 and 2.3.2 require expenditure (and other) data on a project close basis. While Ergon is not*

required to provide this data on an as incurred basis in the tables, it may choose to do so in demonstrating reconciliation if it finds this convenient/ efficient.

We would expect expenditure information reported in Table 2.3.3 to reconcile with the corresponding line items in Table 2.3.4. Where this is not the case, Ergon must provide reasons.

- The HV feeder, LV feeder and distribution substation elements in RIN Table 2.3.4 reconciles with Table 2.3.3. This is expected as they were based on the same data set.
- RIN Table 2.3.4 is unable to be reconciled with Table 2.3.1 and Table 2.3.2. The main causes of difference are:
  - Expenditure in Table 2.3.1 and 2.3.2 were given in real $ 2014/15.
  - Table 2.3.1 only included closed projects, where Table 2.3.4 included open and closed projects.
- Although it is possible to compare specific aspects of the two project lists that underlie the tables it is not possible to reconcile the three tables against each other.

9 BoP 2.4.1 and 2.4.3 – Augex Model

This Basis of Preparation relates to Table 2.4.1 and 2.4.3 as set out in worksheet 2.4 – Augex Model.

The AER requires Energex to provide the following information relating to RIN Table 2.4.1 – AUGEX Model Inputs – Sub-Transmission Lines:

- Line ID
- Primary type of area supplied by line
- Line voltage
- Originating substation
- Terminating substation
- Route line length as at 30 June of year end (2013/14 and 2009/10)
- Maximum demand (weather corrected at 50% PoE)
- Line Rating
  - Thermal
  - N-1 emergency
- Average per annum growth rate in annual line maximum demand (50% PoE) from 2013-14 to 2019-20
- Network segment ID

The AER requires Energex to provide the following information relating to RIN Table 2.4.3 – AUGEX Model Inputs – Subtransmission substation, subtransmission switching station, or zone substation:

- Substation ID
- Subtransmission substation, subtransmission switching station, or zone substation
- Primary type of area supplied by line
- Substation voltage
  - Primary
  - Secondary
- Number of transformers as at 30 June (2013/14 and 2009/10)
- Maximum demand (weather corrected at 50% PoE)
- Substation rating as at 30 June (2013/14 and 2009/10)
  - Tx name plate total (ONAN)
  - Tx name plate total (in service)
  - Tx normal cyclic total
  - Substation normal cyclic
  - N-1 emergency
- Average per annum growth rate in annual line maximum demand (50% PoE) from 2013-14 to 2019-20
- Network segment ID

Information provided contains a mix of actual and estimated data. Refer to table 3 – Actual vs. Estimated Information for further details.

These variables are a part of Regulatory Template 2.4 – Augex Model

9.1 Consistency with Reset RIN Requirements

Table 9.1: Demonstration of Compliance below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 9.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
For each subtransmission line, input maximum demand weather corrected at 50 per cent probability of exceedance. If Energex does not have maximum demand weather corrected at 50 per cent probability of exceedance, input raw adjusted maximum demand, noting such instances in the basis of preparation document(s). i. The historical maximum demand should reflect the demand for planning purposes, and exclude abnormal operating conditions.	Refer section 8.3.2 - Approach: Maximum Demand (Weather Corrected at 50% PoE)
ii. Forecast maximum demand growth rate must be the most realistic expectation of demand at the time of responding to the regulatory information notice, which may or may not be the forecast maximum demand used in developing proposed capital or operating expenditure.	Refer section 8.3.2- Approach – Average Growth rate
iii. The forecast maximum demand growth rate should reflect the approach typically used for planning purposes.	Refer section 8.3.2- Approach – Average Growth rate
For each subtransmission substation, subtransmission switching station and zone substation, input maximum demand weather corrected 50 per cent probability of exceedance. If Energex does not have maximum demand weather corrected at 50 per cent probability of exceedance, input raw adjusted maximum demand, noting such instances in the basis of preparation document(s). i. The historical maximum demand should reflect the demand for planning purposes, and exclude abnormal operating conditions.	Refer section 8.3.2 – Approach - Maximum Demand (Weather Corrected at 50% PoE)
ii. Forecast maximum demand growth rate must be the most realistic expectation of demand at the time of responding to the regulatory information notice, which may or may not be the forecast maximum demand used in developing proposed capital or operating expenditure.	Refer section 8.3.2 – Approach – Average Growth rate
iii. The forecast maximum demand growth rate should reflect the approach typically used for planning purposes.	Refer section 8.3.2 – Approach – Average Growth rate
In the basis of preparation document(s), explain how the maximum demand data reported in the regulatory template was prepared. Where relevant, this explanation should include: i. How the values reported relate to the maximum demand measures that would be used for normal planning purposes.	Refer section 8.3.2 – Approach - Maximum Demand (Weather Corrected at 50% PoE)
ii. Whether the values reported are based upon measured values and, if so, where the measurement point is and how abnormal operating	Refer section 8.3.2 – Approach - Maximum

Requirements (instructions and definitions)	Consistency with requirements
conditions were addressed.	Demand (Weather Corrected at 50% PoE)
iii. Whether the historical values reported are based on estimated (rather than actual measured) demand, and, if so, the basis of the estimation process and how the values were validated.	Refer section 8.3.2 – Approach - Maximum Demand (Weather Corrected at 50% PoE)
iv. How the forecast growth rate was determined.	Refer section 8.3.2 – Approach – Average Growth rate
v. The relationship of the values provided to raw unadjusted maximum demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year.	Refer section 8.3.2 – Approach – Relationship to raw unadjusted demand and 10% PoE
In the *basis of preparation document(s)*, explain how the asset rating values reported in the *regulatory template* were determined. Where relevant, this explanation should include: i. The basis of the calculation of the ratings reported, including asset data measured and assumptions made.	Refer section 8.3.2- Approach – Asset ratings
ii. How the ratings reported for the same assets may be used in *augmentation* planning and/or the operation of the distribution *network*. A. If alternative ratings are used in augmentation planning and/or the operation of the distribution network, explain and define these alternative ratings.	Refer section 8.3.2- Approach – Asset ratings

All variables have been provided in accordance with the AER's instructions and definitions.

The information provided contains a mix of actual and estimated data as set out in Table 9.2 below.

Table 9.2: Actual Vs Estimated

Table	Variable	Source
2.4.1	Line ID	Actual
2.4.1, 2.4.3	Primary type of area supplied by line	Actual
2.4.1	Line voltage	Actual
2.4.1	Originating / Terminating substation	Actual
2.4.1	Route line length as at 30 June	Estimated
2.4.1, 2.4.3	Maximum demand (weather corrected at 50% PoE)	Estimated
2.4.1	Line rating	2013-14: Actual 2009-10: Estimated
2.4.1, 2.4.3	Average per annum growth rate in annual line maximum demand (50% PoE) from 2013-14 to	Estimated

Table	Variable	Source
	2019-20	
2.4.3	Substation ID	Actual
2.4.3	Subtransmission substation, subtransmission switching station, or zone substation	Actual
2.4.3	Substation voltage	Actual
2.4.3	Number of transformers as at 30 June	2013-14: Actual 2009-10: Estimated
2.4.3	Substation rating	2013-14: Actual 2009-10: Estimated

9.2 Sources

Table 9.3 below sets out the sources from which Energex obtained the required information.

Table 9.3: Information sources

Table	Variable	Source
2.4.1	Line ID	Sincal,ERAT2
2.4.1, 2.4.3	Primary type of area supplied by line	SIFT
2.4.1	Line voltage	Sincal, PSS/E
2.4.1	Originating / Terminating substation	Sincal, PSS/E
2.4.1	Route line length	Sincal, GIS
2.4.1	Maximum demand (weather corrected at 50% PoE)	SIFT
2.4.1	Line rating	Sincal, PSS/E
2.4.1	Average per annum growth rate in annual line maximum demand (50% PoE) from 2013-14 to 2019-20	Load Flow results from Sincal and PSS/E
2.4.3	Substation ID	SIFT
2.4.3	Subtransmission substation, subtransmission switching station, or zone substation	SIFT
2.4.3	Substation voltage	SIFT
2.4.3	Number of transformers as at 30 June	SIFT
2.4.3	Maximum demand (weather corrected at 50% PoE)	SIFT

Table	Variable	Source
2.4.3	Substation rating	NFM, SIFT
2.4.3	Average per annum growth rate in annual line maximum demand (50% PoE) from 2013-14 to 2019-20	SIFT

9.3 Methodology

9.3.1 Assumptions

The following assumptions underpin the calculation of these variables:

- In relation to feeder name discrepancies between systems, it was assumed that all feeder names were successfully and correctly matched; and
- All of the results were based on energised operating voltage.

9.3.2 Approach

- All information was sourced based on the AERs requirements. Figures were produced through manual review and cross referencing of sources identified above. Required input elements which are blank indicate that the line or substation did not existing in that reported year. The development of each variable is explained below.

Substation ID / Line ID

- The Substation IDs provided are the three letter substation acronyms of the relevant substations. The Line ID provided are the alpha-numeric ID that Energex uses to identify individual lines.

Primary type of area supplied by line

- The details of the type of area supplied by a substation is sourced from SIFT. The feeders are classified based on the type of substations the feeders are supplying. Hence if a feeder is supplying an “urban” area type zone substation, the feeder would be deemed to supply an “urban” area type.

Voltage / Line Voltage

- The voltage allocated under the AUGEX Model Table 2.4.3 is based on the transformation voltage of the transformer. Hence, for a zone substation equipped with 110/11 kV transformers, the primary voltage would be entered as “110” and the secondary voltage as “11”. For a switching station, the rated voltage of the circuit breakers is used to determine the operating voltage of the switching station. Hence, for a 33 kV switchgear switching station site, the voltage would be entered as “33”.

- The voltage allocated under the AUGEX Model Table 2.4.1 is based on the operational voltage of the feeders. ERAT2 provides an indication of the current operating voltage.

Number of transformers as at 30 June

- The numbers of transformers for each substation is obtained from SIFT.

Route Line Length as at 30 June

- The route line length for each feeder is obtained from GIS for the 110/132kV feeders and from Sincal for the 33kV feeders.

Asset Ratings

- The capacity ratings for each asset were based on industry standard models. Details of the calculations are set out in the Energex Plant Rating Manual5, including the range of assumptions applied, such as manufacturer data, duty cycle, temperatures, type of cooling for transformers, and type of installation for underground cables. Site specific calculations may be undertaken for abnormal situations.

- Transformer name plate rating was obtained from NFM. The transformer name plate in service ratings, transformer normal cyclic rating, substation normal cyclic rating and N-1 emergency cyclic were obtained from SIFT. These were cross-checked against the current databases such as ERAT2.

- Both thermal and N-1 emergency line ratings are obtained from Sincal and PSS/E models. As the feeders in the Energex network are point to point circuits, the rating of a feeder is dictated by the weakest segment of the circuit. The highest utilised feeder segment was used to represent the overall constraint rating of the feeder. The rating data in the model was validated and cross-checked with ERAT2 for all existing network.

- The ratings reported are used for augmentation planning purposes as described under Energex Security Standards – Customer Outcome Standard (COS).

- The asset ratings contained in ERAT2 databases are used for Energex's operating and planning purposes. These ratings also form the basis of the operational ratings used in the DMS, the DMS also contains secondary system limits such as protection system limits and secondary systems ratings. First and final alarms used in the DMS are triggered by measured loads in the network. Table 9.4 over page shows the mapping between the ERAT2 databases and DMS.

[5] Energex, Plant Rating Manual, January 2008

Table 9.4: Mapping between planning and operating asset ratings

Plant type	Planners' rating types			DMS	
	Nominal	Emergency	Short duration emergency	First alarm	Final alarm
OH Circuit	Cyclic rating	Cyclic rating	2 Hour rating		Cyclic rating
UG Circuit	Cyclic rating	Cyclic rating	2 Hour rating		Cyclic rating
CB/RE	Nameplate rating	Nameplate rating	2 Hour rating	90% of final alarm value	Nameplate rating
CT	Cyclic rating	Cyclic rating			Cyclic rating
Power Transformer	Normal Cyclic	Emergency Cyclic	2 Hour rating		Emergency Cyclic

- As shown in Table 9.4, above, there is a clear relationship between the use of ratings for planning and operations.
- The AER's Augex Model Handbook6 requires that the nominal thermal rating is used to ensure the rating provided is independent of the unique network arrangements of Energex. To address this requirement, Energex used the nominal rating for its assets based on standard conditions, as set out in the Plant Rating Manual7, that are stored in the ERAT and ERAT2 databases. The following two exceptions were made:
  - Transformers operated in parallel may not share load equally. This can be due to differences in impedance. Therefore, substation ratings were calculated values. Based on the rating obtained from ERAT2, the SIFT calculated the substation rating taking into account the load sharing between transformers.
- Energex considered that the use of these ratings was appropriate for the Augex model, and was the most accurate reflection of data used to forecast augmentation requirements.

Average per annum growth rate

- The average per annum growth rate for line and substation is calculated based on the maximum demand (weather corrected at 50% PoE) data for years 2013/14 and 2019/20. The following formula is used in calculating the average per annum growth rate:

[6] AER augmentation model handbook, November 2013, section 5
[7] Energex, Plant Rating Manual, January 2008

$$\text{Average per annum growth rate} = \sqrt[6]{\frac{2019/20\_MaxDemand}{2013/14\_MaxDemand}}$$

- Forecast growth was based on the most realistic demand forecasts at the time of responding to the Reset RIN.
- Forecast growth is based on the same forecast used for planning purposes.

Network Segment ID

- The network segment ID for substations is categorised based on the number of operating transformers at the substation. The information of the number of transformer is obtained from SIFT, and the substation is classified under a pre-defined AUGEX Model network segment group (Zone and Sub-Transmission substations).
- The network segment ID for lines is categorised based on its individual physical network characteristics. The line physical network configuration is obtained through Energex DMS system which highlights the operating line configuration, and is classified under a pre-defined AUGEX Model network segment group (Sub-transmission lines).
- The network segments are then further divided based on the growth rate.
- RIN table 2.4.5 defines the network segment group in the AUGEX Model.

Maximum Demand (Weather Corrected at 50% PoE)

- Energex employed a bottom up approach to develop the ten year zone substation maximum demand forecasts using validated historical peak demands and expected load growth based on demographic and appliance information in small area grids. Larger block loads were included separately after validation for size and timing by Asset Managers.
- The zone substation peak demand forecasts were then aggregated up to the ten year bulk supply point, and transmission connection point demand forecasts, and accounted for diversity of individual zone substation peak demands and network losses. This aggregated forecast was then reconciled with the independent system demand forecast and adjusted as required.
- The high level process used to develop the ten year substation demand forecast was as follows:
  - Validated uncompensated substation peak demands were determined for summer 2013/14 from the SCADA system. This is accurate within ±5.0%, which was the best available data.
  - Minimum and maximum temperature at five Bureau of Meteorology weather stations were regressed against substation daily maximum demand to assess the impact of each set of weather data on substation demand (Amberley,

Archerfield airport, Coolangatta airport, Brisbane airport and Maroochydore airport). The best fit relationship is used to determine the temperature adjustment.

- Industrial substations tend not to be sensitive to temperature and the 50% PoE and 10% PoE adjustments were based solely on demand variation.
- Previous substation peak demand forecasts were reviewed against temperature adjusted results and causes of forecast error were identified.
- Starting values for MVA, MW and MVAr were calculated for four periods – summer day, summer night, winter day and winter night.
- Demographic and population analysis was undertaken and customer load profiles are prepared for Energex.
- Year-on-year peak demand growth rates were determined from the customer load profiles prepared for Energex, historical growth trends and local knowledge from Asset Managers using a panel review (Delphi) process.
- Size and timing of new block loads were reviewed and validated with Asset Managers before inclusion in the forecast.
- Size and timing of load transfers were also reviewed with Asset Managers before inclusion in the forecast.
- Timing and scope of proposed projects were reviewed with development planners before inclusion in the forecast.
- The growth rates, block loads, transfers and projects were applied to the starting values to determine the forecast demand for each of the ten years starting from a coincident demand basis.
- Zone substation forecast peak demands were aggregated up to transmission connection point demands through the bulk supply substations using appropriate coincidence factors and losses.
- Reconciliation of the total aggregated demand with the independently produced system demand forecast ensures consistency for the ten year forecast period.
- Includes peak demand reduction through audio frequency load control (AFLC) based demand management.

- Substation peak demand forecasts are reviewed each season and compared with previous forecasts.
- The maximum demand (weather corrected at 50% PoE) for substation is obtained from SIFT. For lines, it is based on the load flow results of Sincal and PSS/E based on the maximum demand (weather corrected at 50% PoE) of the relevant substations.
- The forecast utilises SCADA measurements of transformer load and independent weather stations to provide temperature data. The measurements were validated to account for abnormal conditions such as network maintenance or outages as part of the forecasting methodology.

- The maximum demand data provided in Reset RIN tables 2.4.1, and 2.4.3 for sub-transmission lines, sub-transmission substations and zone substations align with maximum demand forecast used in Energex's normal planning process.

Relationship to raw unadjusted demand and 10% PoE

- The 2013-14 summer native demand peaked at 4373 MW at 3pm on Wednesday 22 January 2014, when the maximum temperature reached 38.1°C at Amberley. The temperature adjusted maximum demand fell short of the 50% PoE forecast of 4710 MW (forecast last year) by 338 MW (7.1%).

- The average difference between 50% PoE and 10% PoE at a system level during the forthcoming regulatory control period was approximately 14%.

9.4 Estimated Information

- Details of variables reported as Estimated Information are included in Table 9.2: Actual Vs Estimated.

9.4.1 Justification for Estimated Information

- Energex has populated the required figures in RIN Table 2.4.1 and Table 2.4.3 based on all available historical information where possible.

- Where historical information was not available, estimated information is provided.

- Load flow results are considered estimated information as it is calculated using simulation models.

- The average annual growth rates are deemed estimated as it is calculated based on a forecasted 50% PoE maximum demand for year 2019/20.

9.4.2 Basis for Estimated Information

- Route line length data was extracted from the simulation models or corporate GIS system. The GIS can only accurately extract data based on the latest (last known) feeder names associated with the segment, as such a mapping exercise was needed to match the historical feeder name to the latest name. There have been numerous changes in the 33kV network over the last 5 years, with some complex works involving cutting and swapping feeder segments to reconfigure the network.

- Line rating data was extracted from the past simulation models as the corporate rating data system, ERAT2, does not retain historical records. The data from past models is considered a credible source of information; however, accuracy of these data cannot be verified.

- Further, there were instances were due to a change of systems and record keeping practices where records were changed and overwritten rather than being archived, actual data was not available.

- The growth rate for each line is calculated assuming no augmentation work being initiated since 2013/14.
- The growth rate for each substation is calculated assuming approved augmentation works as of June 2014 are delivered by the proposed commissioning dates.

9.5 Explanatory notes

9.5.1 Rating Conversion

- Energex line ratings are expressed in current capacity (A), the conversion from A to MVA was done assuming a nominal voltage. For example, for a 33kV feeder, the following calculation applies:

$$\text{Rating (A)} / 1{,}000 \times 33\ \text{(kV)} \times \sqrt{3} = \text{Rating (MVA)}$$

9.5.2 Assets excluded from tables 2.4.1 and 2.4.3

- The assets detailed in Table 9.5 were commissioned as of 30 Jun 2014 but as these assets were commissioned after the Summer season, no weather corrected 50% PoE load was obtainable. These assets were excluded from Reset RIN tables 2.4.1 and 2.4.3.

Table 9.5: Assets excluded

Table	Substation / Feeder	Commissioning date
2.4.1	F3374	26-Jun-2014
2.4.1	F3960	03-Apr-2014
2.4.1	F3972	16-May-2014
2.4.3	WSS Zone Substation	26-Jun-2014
2.4.3	YMT Zone Substation	03-Apr2014

10 BoP 2.4.2 – Augex Model Inputs – Asset Status – High Voltage Feeders

This Basis of Preparation relates to Table 2.4.2 as set out in worksheet 2.4 – Augex Model.

The AER requires Energex to provide the following information relating to table 2.4.2 – Augex model inputs – asset status – high voltage feeders:

- **high voltage feeder ID**
- **high voltage feeder type**
- **voltage level**
- **originating substation**
- **route line length as at 30 June – 2013-14 and 2009-10**
- **maximum demand (weather corrected at 50% PoE) – 2013-14 and 2009-10**
- **Thermal rating and operational rating – 2013-14 and 2009-10**
- **Average per annum growth rate in annual high voltage feeder demand (50% PoE) from 2013-14 to 2019/20**
- **Network segment ID.**

Actual information was provided for 13/14 radial (Urban and Rural) feeder lengths, load, rating, feeder type and voltage level.

Estimated information was provided for 13/14 and 09/10 feeder lengths for feeders with in the CBD High voltage feeder type (mesh networks); 09/10 radial (urban and rural) feeder lengths; growth rates and high voltage feeder type for feeders that don't have a reliability classification.

These variables are a part of Regulatory Template 2.4 – Augex Model

10.1 Consistency with Reset RIN Requirements

Table 8.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 10.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
If an asset of Energex does not exactly match the definitions in appendix F, Energex must include the asset in the regulatory template that most closely reflects its primary nature. Energex must clearly label such assets and note such assets in the basis of preparation document(s).	Demonstrated in section 10.3.2 Approach – List all reportable feeders and originating substation
Complete the regulatory template by:	Demonstrated in section

Requirements (instructions and definitions)	Consistency with requirements
i. inserting a row for each high voltage feeder on Energex's network; and ii. inputting the required details.	10.3.2 Approach
Each row should represent data for an individual circuit. i. Each high voltage feeder must be identified by a unique ID number.	Demonstrated in section 10.3.2 Approach – List all reportable feeders and originating substation
The high voltage feeder rating should be based upon the main trunk segment exiting the substation.	Demonstrated in section 10.3.2 Approach – Rating
The maximum demand should be the demand measured at the feeder exit from the associated substation.	Demonstrated in section 10.3.2 Approach – Maximum Demand
For each high voltage feeder, input maximum demand weather corrected at 50 per cent probability of exceedance. If Energex does not have maximum demand weather corrected at 50 per cent probability of exceedance, input raw adjusted maximum demand, noting such instances in the basis of preparation document(s). i. The historical maximum demand should reflect the demand for planning purposes, and exclude abnormal operating conditions. ii. Forecast maximum demand growth rate must be the most realistic expectation of demand at the time of responding to the regulatory information notice, which may or may not be the forecast maximum demand used in developing proposed capital or operating expenditure. iii. The forecast maximum demand growth rate should reflect the approach typically used for planning purposes.	Demonstrated in section 10.3.2 Approach – Maximum Demand
In the basis of preparation document(s), explain how the maximum demand data reported in the regulatory template was prepared. Where relevant, this explanation should include: i. How the values reported relate to the maximum demand measures that would be used for normal planning purposes. ii. Whether the values reported are based upon measured values and, if so, where the measurement point is and how abnormal operating conditions were addressed. iii. Whether the historical values reported are based on estimated (rather than actual measured) demand, and, if so, the basis of the estimation process and how the values were validated. iv. How the forecast growth rate was determined. v. The relationship of the values provided to raw unadjusted maximum	Demonstrated in section 10.3.2 Approach – Maximum Demand and 10.3.2 Approach – Average per annum growth rate in annual high voltage feeder maximum demand from 2013/14 to 2019/20

Requirements (instructions and definitions)	Consistency with requirements
demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year.	
In the basis of preparation document(s), explain how the asset rating values reported in the regulatory template were determined. Where relevant, this explanation should include: i. The basis of the calculation of the ratings reported, including asset data measured and assumptions made. ii. How the ratings reported for the same assets may be used in augmentation planning and/or the operation of the distribution network. A. If alternative ratings are used in augmentation planning and/or the operation of the distribution	Demonstrated in section 10.3.2 Approach – Rating

Actual information was provided for:

- 13/14 radial (Urban and Rural) feeder lengths;
- Load;
- Rating;
- Feeder type; and
- Voltage level.

Whilst estimated information was provided for:

- Both 13/14 and 09/10 feeder lengths for feeders with in the CBD High voltage feeder type (mesh networks);
- 09/10 radial (Urban and Rural) feeder lengths;
- Growth rates; and
- High Voltage feeder type for feeders that don’t have a reliability classification

10.2 Sources

Table 10.2, over page, sets out the sources from which Energex obtained the required information:

Table 10.2: Information sources

Variable	Source
High voltage feeder ID	NetPlan
High voltage feeder type	NetPlan
Voltage level	NetPlan
Originating substation	NetPlan
Route line length as at 30 June in 2013/14 and 2009/10	DINIS and NFM
Maximum demand (weather corrected at 50% PoE) – 2013/14 and 2009/10	NetPlan, NMP
Thermal rating and operational rating in 2013/14 and 2009/10	NetPlan, NMP
Average per annum growth rate in annual high voltage feeder demand (50% PoE) from 2013/14 to 2019/20	NetPlan
Network segment ID.	NetPlan

10.3 Methodology

- The data presented in Reset RIN Table 2.4.2 has been prepared by sourcing data from corporate data sources and published Annual Network Management Plan (NMP) reports wherever data was no longer available.
- NetPlan is a tool used by Energex to forecast and plan the 11kV network. NetPlan includes ratings, loads, forecasts and asset relationships and future approved projects as required for identifying emerging 11kV network limitations in the business as usual functions of the Energex distribution network planning.

10.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- That all meshed network construction is to CBD standards.
- That load growth associated with block loads between 2013/14 and 2016/17 will trend between 2016/17 and 2019/20.

- Conversion between maximum demand recorded in amps and MVA have assumed 11 kV and unity power factor. MW calculation assumes 11 kV.

10.3.2 Approach

Energex applied the following approach to obtain the required information:

1) NetPlan and DINIS network models were used to provide the majority of information.

2) Where data was unavailable in NetPlan or DINIS then NFM data or data previously reported in the NMP were used as supplementary sources.

3) Calculations were made from source data to provide information in the format requested.

List all reportable feeders and originating substation

- NetPlan was used to obtain a list of unique feeder names and their originating substation that were commissioned for the 2009/10 period and/or for the 2013/14 period.

- The list of feeders commissioned for summer 2009/10 was cross-referenced against the list of feeders with forecast summer loads in the NMP. If a feeder was found to be missing from NetPlan's 2009/10 data, then it was added to the list of feeders.

Feeder types

- NetPlan contains records for the current reliability classification of feeders. In the instances where there was a feeder with historic load that did not have categorisation data available it was given a category based on the majority of other feeders connected to the same originating zone substation.

Voltage Level

- All HV feeders in the Energex network are 11 kV.

Route Length

- For 2013/14 the feeder length data was captured from the DINIS network model using automated loadflow results that were run in June 2014. The lengths for radial feeders were able to be recorded directly from the loadflow results that were recorded. Feeder lengths for meshed network areas were calculated by taking the length of the complete mesh and dividing by the number of zone substation feeders in the mesh.

- For 2009/10 the feeder length data was taken from the NFM database. For mesh networks the NFM data source does not allow the tracking of mesh feeder membership for cables between switching stations. The lengths reported only represent the length from the zone substation to the first switching station as the data available does not allow the association between the cables between switching sites and the mesh that they were part of at a point in time. Due to name changes in the system some radial feeder historic lengths were unable to be identified in NFM data. If these feeders also exist in the 2013/14 data then this value was used.

Maximum Demand

- As part of the forecasting process Energex assesses the 50% PoE maximum demand after each season for each 11 kV feeder. This involved allowing for abnormal operating conditions by identifying and removing any temporary (abnormal) loads and transfers; then analysing daily peak loads for day and night to identify the load expected at a 50% and 10% PoE temperature. This assessment is recorded in amps. The data does not capture voltage or power factor at that point in time. The maximum demand presented assumes unity power factor and 11 kV in the conversion to MW and MVA.

- For 126 feeders, the historic (2009/10) maximum demand was no longer available in NetPlan. In these cases the forecast peak demand from the NMP was used. This forecast value was based on weather correction of 2008/09 loads and growth rates and block loads at the time and allows the overall load growth of the period to be captured for the network segments.

- The peak demand shown is reported at the season (summer day, summer night, winter day, and winter night) of peak utilisation for that feeder. The maximum demand data provided in Reset RIN table 2.4.2 align with maximum demand forecast used in Energex's normal planning process.

Rating

- NetPlan captures the current and future changes to rating only and does not record historic changes to ratings.

- The 2013/14 ratings are from NetPlan and are presented for the same season (summer day, summer night, winter day, and winter night) that was used for the peak demand, i.e. the season of maximum utilisation.

- The 2009/10 ratings are presented from the Network Management Plan 2009/10 to 2013/14.

- Thermal ratings and operational ratings are the same. Energex has used the feeder trunk assumption as recommended in section 5.1.2 of the Augex guidelines. The rating used is the lowest rating of the first three segments of the feeder.

Average per annum growth rate in annual high voltage feeder maximum demand from 2013/14 to 2019/20

- The growth rate for each feeder was calculated using the maximum demand at 2013/14 and the forecast load for 2016/17. For feeders that are forecast to be decommissioned (or renamed) the growth is shown as -100%. For feeders forecast to be added after 2013/14 the load has been allocated to another feeder within the same Network segment ID. Once all loads were allocated then the compound annual growth rate for each feeder was calculated by the following:

$$Growth\ Rate = \left(\sqrt[3]{\frac{Load\ 2016/17}{Load\ 2013/14}}\right) - 1$$

Network segment ID

- The Network segment ID was allocated by using the feeder type for CBD, urban and rural feeders. CBD radial and 2 feeder mesh networks are separated from mesh networks with 3 or more feeders. The network segments are then further divided based on growth rate.

10.4 Estimated Information

Estimated data has been used for the following variables:

- Both 2009/10 and 2013/14 feeder lengths for feeders within the CBD High voltage feeder type (mesh networks) and partially for 2009/10 radial (Urban and Rural) feeder lengths;
- Average per annum growth rate in annual high voltage feeder maximum demand (50% PoE) from 2013/14 to 2019/20.
- High Voltage feeder type for feeders that don't have a reliability classification. Details are provided in Table 10.3 below.

Table 10.3: High Voltage Feeders without Reliability Classifications

High Voltage Feeder ID	High Voltage Feeder ID	High Voltage Feeder ID
AFD3A	HMT9A	RLA7A
ARG9A	JDL4A	SBH13A
CHL11A	LHM1A	SPE20A
CHL6A	LHM4A	TWG15A
CLD1A	MDH3A	WCL10A
CMV11A	MFD11A	WCL11A
CPL5A	MLS9A	WED20A
CSE21A	NDH5A	ZMR4A

High Voltage Feeder ID	High Voltage Feeder ID	High Voltage Feeder ID
CSE23A	NMK17A	
CSE27A	RBY7A	
GYM7A	RBY9A	
HMT10A	RLA4A	
HMT3A	RLA5A	

10.4.1 Justification for Estimated Information

- For line length data for CBD feeders where meshed networks are used it was necessary to estimate required information because the length of the individual feeders making up the mesh cannot be determined as there are no open points to denote segregation of the feeders that form the mesh. For CBD feeders in 2009/10, where NFM data was used to source data for route length, there are no records to associate cables between switching sites with mesh networks or the zone substation feeders. As a result it is necessary to use a different estimate to populate the length of the CBD feeders in 2009/10.

- For determining the average per annum growth rate in annual high voltage feeder maximum demand (50% PoE) from 2013/14 to 2019/20 it was necessary to estimate the required information because it is derived from load forecasts.

- Where a feeder was unable to be identified in the available reliability classification data, an estimate was required to properly allocate feeders to appropriate feeder type and subsequent segment IDs.

10.4.2 Basis for Estimated Information

Lengths

- For 2013/14 route length data for CBD feeders where meshed networks are used it was necessary to estimate required information because the length of individual feeders cannot be determined as there are no open points to denote segregation of the feeders that form the mesh. To provide a length for each feeder individually the length of the cable in the mesh was divided by the number of feeders in that particular mesh. This estimate is appropriate because it is based on actual data for the assets involved and is the best method to provide data on a per feeder basis as required by the Reset RIN.

- For the 2009/10 route length data there was no DINIS model available so NFM data was used for feeder lengths. For CBD areas the NFM data gives cables between switching sites a unique name but does not associate them with the mesh that they were part of at that point in time. Consequently the best estimate available is to provide either the 2013-14 length or where that feeder is not in the 2013/14 DINIS model (has been decommissioned) then use the length from the GIS between the zone substation and the first switching station to which it connects.

Where urban or rural feeders were not able to be identified in the historic NFM data, then the 2013/14 lengths were used.

Growth rates

- The average per annum growth rate in annual high voltage feeder maximum demand (50% PoE) from 2013/14 to 2019/20 was estimated using the NetPlan forecast maximum demand for 2016/17 and the recorded weather corrected maximum demand for 2013/14. Due to volatility in long range forecasting of localised load growth on 11kV feeders this shorter period is more reflective of longer term trends.
- NetPlan includes network changes that are planned as part of approved projects. Consequently there are network changes such as feeder renaming and load shifts which affect individual feeders. The 2016/17 forecast maximum demand also includes feeders that do not currently exist (with load transfers to them from existing feeders). These proposed feeders have zero load in the 2013/14 maximum demand so growth on these feeders cannot be modelled as a growth rate. To ensure that this data reflects the overall network growth the load forecast from these new feeders has been allocated to another feeder from that category which has load in 2013/14.

Feeder types

- The feeder type was obtained from the NetPlan database. Where the feeder type was not available in NetPlan the feeder was assigned the feeder type of the majority of the feeders from the originating substation. The feeder was also assigned the relevant Network Segment ID for that feeder type.

11 BoP 2.4.4 – Augex Model Inputs - Distribution

This Basis of Preparation relates to Table 2.4.4 as set out in worksheet 2.4 – Augex Model.

RIN Table 2.4.4 includes both historic and forecast data. This BoP applies only to historic data.

The AER requires Energex to provide the following information relating to table 2.4.4 – Augex model inputs – asset status – distribution substations:

- **Distribution substation category ID**
- **Description of substation category**
- **Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substation category that were within the specified utilisation bands – 2013/14.**
- **Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substation category – MVA – 2013/14**
- **Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substation category that were within the specified utilisation bands – 2009/10.**
- **Aggregate of the normal cyclic ratings of all individual distribution substations in the distribution substation category – MVA – 2009/10**

All data was Estimated Information.

These variables are a part of Regulatory Template 2.4 – Augex Model

11.1 Consistency with Reset RIN Requirements

Table 11.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 11.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
As it will be difficult to provide data for individual distribution substations, distribution substation categories should be formed that capture sets of distribution substations on Energex's network, based upon factors such as: i. pole-mounted or ground-mounted distribution substations, ii. distribution substation ratings or iii. the area types supplied (i.e., CBD, urban, rural).	Refer section 11.3.1 Assumptions - Define Network Segments

Requirements (instructions and definitions)	Consistency with requirements
Each distribution substation category must be identified by a unique ID number.	Categories include unique numbers
The description provided for each distribution substation category should identify characteristics such as pole-mounted or ground-mounted, range of ratings covered, area types supplied, etc.	Refer section 11.3.1 Assumptions - Define Network Segments
Where actual maximum demand is not measured at individual distribution substations within a category, estimate maximum demand and utilisation based on customer types and numbers supplied from the distribution substation.	Refer section 11.3.1 Assumptions - Utilisation profile 2013-14
Input specified information relating to maximum demand weather corrected at 50 per cent probability of exceedance. If Energex does not have maximum demand weather corrected at 50 per cent probability of exceedance, input specified information relating to raw adjusted maximum demand, noting such instances in the basis of preparation document(s).	
i. The historical maximum demand should reflect the demand for planning purposes, and exclude abnormal operating conditions.	Refer section 11.3.1 Assumptions - Utilisation profile 2013-14
ii. Forecast maximum demand growth rate must be the most realistic expectation of demand at the time of responding to the regulatory information notice, which may or may not be the forecast maximum demand used in developing proposed capital or operating expenditure.	Refer section 11.3.1 Assumptions - Growth Rates
iii. The forecast maximum demand growth rate should reflect the approach typically used for planning purposes.	Refer section 11.3.1 Assumptions - Growth Rates
In the basis of preparation document(s), explain how the maximum demand data reported in the regulatory template was prepared. Where relevant, this explanation should include:	-
i. How the values reported relate to the maximum demand measures that would be used for normal planning purposes.	Refer section 11.3.1 Assumptions - Utilisation profile 2013-14
ii. Whether the values reported are based upon measured values and, if so, where the measurement point is and how abnormal operating conditions were addressed.	Refer section 11.3.1 Assumptions - Utilisation profile 2013-14
iii. Whether the historical values reported are based on estimated	Refer section 11.3.1

Requirements (instructions and definitions)	Consistency with requirements
(rather than actual measured) demand, and, if so, the basis of the estimation process and how the values were validated.	Assumptions - Utilisation profile 2013-14 and Utilisation profile 2009-10
iv. How the forecast growth rate was determined.	Refer section 11.3.1 Assumptions - Growth Rates
v. The relationship of the values provided to raw unadjusted maximum demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year	Refer section 11.3.1 Assumptions - Growth Rates Energex does not produce 10% PoE and 50% PoE forecasts for distribution substations
In the basis of preparation document(s), explain how the asset rating values reported in the regulatory template were determined. Where relevant, this explanation should include: i. The basis of the calculation of the ratings reported, including asset data measured and assumptions made. ii. How the ratings reported for the same assets may be used in augmentation planning and/or the operation of the distribution network. If alternative ratings are used in augmentation planning and/or the operation of the distribution network, explain and define these alternative ratings.	Refer section 11.3.1 Assumptions - Installed capacity

11.2 Sources

Table 11.2 below sets out the sources from which Energex obtained the required information.

Table 11.2: Information sources

Variable	Source
Utilisation Profile	NFM & HeadEnd Database
Aggregate of the normal cyclic ratings	NFM
Growth Rate	NetPlan

- NetPlan is an Energex developed distribution planning tool and database.
- Network Facility Management (NFM) is the main database used by Energex to record and manage asset data and information regarding asset outages.
- The Headend database stores metering data collected through the metering collection engine.

11.3 Methodology

A summary of the process applied is as follows:

- Define network segments
- Establish installed capacity of distribution transformers in 2013-14 for each network segment
- Calculated utilisation profile of known population using metering and MDI data
- Applied utilisation profile to distribution transformers in all network segments based on installed capacity
- Calculate forecast growth rate
- Back cast 2009-10 utilisation profile based on forecast growth rate

11.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Calculating the Growth Rates only the underlying growth has been included within the model, as works initiated from block loads are considered customer initiated.
- Urban and Rural network segments have been assumed to be Domestic customers thus a normal cyclic rating for the utilisation threshold for domestic has been applied to both categories. Similarly CBD network segments have been assumed to be Dry Type Transformers.

11.3.2 Approach

Energex applied the following approach to obtain the required information:

Define network segments

- Energex defined distribution substation segment groups largely based on feeder categories for CBD, urban and rural, as specified in the STPIS. Energex does not have any long rural distribution substations.

- Energex disaggregated the segment groups based on distribution transformer capacity in kVA:
  - ≤25 kVA distribution transformers (Only Urban and Rural)
  - 30 kVA to 63 kVA distribution transformers (Only Urban and Rural)
  - 75 kVA to 100 kVA distribution transformers (Only Urban and Rural)
  - 150 kVA to 315 kVA distribution transformers
  - 500 kVA distribution transformers
  - 750 kVA distribution transformers
  - 1000 kVA distribution transformers
  - ≥1500 kVA distribution transformers
- Categories include pole, ground mounted and indoor transformers.
- The network segmentation for Distribution Substations and LV was based on the current construction standards and the population of existing transformers.

Installed capacity

- Installed capacity for each transformer was extracted from NFM. The extract included all distribution transformer assets with site IDs beginning with SS (within substation), SP (pole mounted), SG (ground mounted) and SC (substation cubical).
- Asset capacity has been provided based on the nameplate rating each transformer. Normal cyclic ratings have been taken into account in the development of the Utilisation threshold parameters provided in table 2.4.5 of the reset RIN. Normal cyclic ratings are used to trigger distribution transformer augmentation based on record demand at specific transformers.

Utilisation profile 2013-14

Energex calculated the utilisation profile for all distribution transformers based on a sample of 23% transformers over the last four years. Energex applied the following approach to calculate the utilisation profile:

1) Four years of MDI readings were used with records starting from January 2010 to May 2014 taken at different periods throughout the year with 9714 individual records. MDI readings were only available for transformers with a capacity of 200 kVA and above.

2) Digital Meter readings for a 6 month period starting from 1/10/2013 were also extracted, this period was taken as it coincided with the system peak on the 22nd of January 2014 at 3:00pm. The top 2% of all recorded peak values from digital meters were removed to exclude any switching peaks.

3) The MDI readings and the Digital meter readings were then combined, with the Digital Meter readings taking precedence over the MDI readings if data was available for both, totalling 11,013 individual records.

4) A distribution profile was developed with the combined data by taking all available utilisation data for all transformers regardless of name plate rating and developing a profile of the percentage utilisation.

5) The transformer utilisation profile was applied to the summated transformer capacity (MVA) for each transformer size to determine an overall utilisation profile which was applied to each network segment

MDI and digital meter readings are used by Energex to trigger distribution transformer augmentation.

Growth rates

- The growth rates for each network segment were calculated based on the HV feeder demand forecast methodology, excluding customer block loads. Block loads were excluded from growth rate as they were addressed through customer initiated projects.

- The growth rates for each HV feeder were extracted from the Netplan database, the average of each reliability category was used for corresponding distribution substation categories.

- MDI and digital meter readings are used by Energex to trigger distribution transformer augmentation. Energex does not develop 10% PoE or 50% PoE maximum demand forecasts for individual distribution transformers.

Utilisation profile 2009-10

- Energex does not record historic distribution transformer utilisation profiles. The utilisation profile for 2009-10 was calculated by de-escalating the 2013-14 utilisation profile using the forecast growth rates for CBD, urban and rural distribution substations.

11.4 Estimated Information

- All date provided in table 2.4.4 is estimated due to the process required to provide data consistent with the Reset RIN.

11.4.1 Justification for Estimated Information

- Energex does not record annual data for all distribution transformers, therefore estimates were required to provide data for 2013-14 and 2009-10.

11.4.2 Basis for Estimated Information

- Estimates are based on data recorded against 23% of the total population in the last 4 years; this data provides the best estimate of current distribution transformer utilisation.

12 BoP 2.4.5 – Augex Model Inputs – Network Segment Data

This Basis of Preparation relates to Table 2.4.5 as set out in worksheet 2.4 – Augex Model. RIN Table 2.4.5 includes both historic and forecast data. This BoP applies only to historical data.

The AER requires Energex to provide the following information relating to table 2.4.5 – Augex model inputs – network segment group:

- **Network segment ID**
- **Network segment title**
- **AER segment group**
- **Average unit cost of augmentation for the network segment for the next regulatory control period ($000's per MVA)**
- **Capacity factor for the period**
- **Mean value of the utilisation threshold**
- **Standard deviation of the utilisation threshold for the period**

All data was estimated.

These variables are a part of Regulatory Template 2.4 – Augex Model

12.1 Consistency with Reset RIN Requirements

Table 12.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 12.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
All *historic opex* and *historic capex* provided to the AER in response to this *Notice* must be in nominal dollars, unless specified otherwise.	Advice received from the AER (Via email correspondence) instructed that historic augmentation unit cost should be reported in Real June 2015 $.
Energex must define the most appropriate network segments. • Individual network segments should be defined to capture differences in the main drivers of augmentation, such as growth in maximum demand, augmentation unit costs, or utilisation thresholds. • In forming individual network segments, it should be considered that this data will be used for the Augex model, which is intended to	Refer to section 1.1.1.1 - Network segments

Requirements (instructions and definitions)	Consistency with requirements
forecast at an aggregate level and not for specific circumstances.	
In completing the AER segment group details in the regulatory template, select the most appropriate group from the following list: i. subtransmission lines (ID number: 1) ii. subtransmission substations and subtransmission switching stations (ID number: 2) iii. zone substations (ID number: 3) iv. high voltage feeders – CBD (ID number: 4) v. high voltage feeders – urban (ID number: 5) vi. high voltage feeders - short rural (ID number: 6) vii. high voltage feeders - long rural (ID number: 7) viii. distribution substations – CBD, including downstream low voltage network (ID number: 8) ix. distribution substations – urban, including downstream low voltage network (ID number: 9) x. distribution substations – short rural, including downstream low voltage network (ID number: 10) xi. distribution substations – long rural, including downstream low voltage network (ID number: 11)	Refer to 1.1.1.1.1 - Segment groups
In the basis of preparation document(s), provide a definition and description of each network segment reported in the regulatory template, including details on: i. boundaries with other connecting network segments; and ii. the main reason why the network segment was reported as an individual network segment and not bundled with other network segments.	Refer to section 1.1.1.1.2 - Network segments composition
In the basis of preparation document(s), explain how the unit costs and capacity factors reported in the regulatory template were calculated for each network segment. This must cover the following:	
i. The methodology, data sources, and assumptions used to derive the augmentation unit cost or capacity factor.	Refer to section 1.1.1.2.1 - Methodology, data sources and assumptions
ii. The relationship of the parameters to actual historical augmentation projects, including the capacity added through these projects and the cost of these projects.	Refer to section 1.1.1.2.2- Relationship to historical augmentation

Requirements (instructions and definitions)	Consistency with requirements
iii. The possibility of double-counting in the estimates (for example, when an individual project may add capacity to multiple network segments), and the process applied to ensure that this is appropriately addressed.	Refer to section 1.1.1.3.3- Possibility of double counting
iv. The process applied to verify that the augmentation unit costs and capacity factors reported are a reasonable estimate for the network segment.	Refer to section 1.1.1.4.5 - Verification of parameters
In the basis of preparation document(s), explain of how the utilisation thresholds reported in the regulatory template were calculated for each network segment. This must cover the following:	
i. The methodology, data sources, and assumptions used to derive the utilisation threshold.	Refer to section 1.1.1.2.1 - Methodology, data sources and assumptions
ii. The relationship to internal and/or external planning criteria that define when an augmentation is required.	Refer to section 1.1.1.4.4 - Relationship to internal or external planning criteria
iii. The relationship to actual historical utilisation at the time that augmentations occurred for that network segment.	Refer to section 1.1.1.4.2 - Relationship to historic utilisation
iv. Views on the most appropriate probability distribution to simulate the augmentation needs of that network segment.	Refer to section 1.1.1.4.3 - Probability distribution
v. The process applied to verify that the utilisation thresholds are a reasonable estimate of the utilisation limit for the network segments.	Refer to section 1.1.1.4.5 - Verification of parameters

All historic data in Reset RIN table 2.4.5 is Estimated Information.

12.2 Methodology

Data provided in Reset RIN table 2.4.5 has been developed in accordance with the AER's Augex model handbook November 2013.

1.1.1.1 Network segments

1.1.1.1.1 Segment groups

- The segment groups are specified by the AER in Regulatory Template 2.4.5 and are defined in Table 4.12.2 below.

Table 4.12.2 - AER Segment group definitions

ID	Segment group	AER Definition
1	Subtransmission lines	A distribution line with a nominal voltage that is above 33 kV, and connects a sub-transmission substation to a zone substation. Includes all connected lines and cables from the point of origin to the normally-open points or line/cable terminations.
2	Subtransmission substations and switching stations	A substation on a distribution network that transforms any voltage to levels above 33 kV or switching station that connects to multiple circuits above 33 kV but does not contain a transformer. For the purposes of populating regulatory template 2.4 (Augex model), a sub-transmission substation is a substation on a distribution network that transforms any voltage to levels above 22 kV and is not a bulk supply point. Refer to the QLD Reset RIN 2015 Appendix F for further details regarding this definition.
3	Zone substations	A substation on a distribution network that transforms any voltage above 33 kV to levels at or below 33 kV but above 1 kV. Refer to the QLD Reset RIN 2015 Appendix F for further details regarding this definition.
4	HV feeders – (by feeder category)	A distribution line with a nominal voltage that is at or below 33 kV and above 1 kV, and connects distribution substations to a zone substation. Includes all connected lines and cables from the point of origin (typically a zone substation) to the normally-open points or line/cable terminations. Feeder categories have the meaning described in the Service Target Performance Incentive Scheme, November 2009.

5	Distribution substation – (by feeder category and including downstream LV network)	A substation on a distribution network that transforms voltage of levels at or below 33 kV but above 1 kV to levels below 1 kV. Feeder categories have the meaning described in the Service Target Performance Incentive Scheme, November 2009.

1.1.1.1.1.1 Departures from the AER's definitions

- The following sections list the differences between AER and Energex definitions of asset groups, and provide justification for a departure from the AER's definitions.

1.1.1.1.1.1.1 Sub-transmission lines

- Energex uses a different definition for sub-transmission in its normal day to day operations. The key difference is that Energex considers sub-transmission to include 33 kV lines, as the purpose of those lines is to provide interconnection between zone substations, not to connect zone substations to distribution substations as indicated by the Reset RIN HV feeder definitions.
- Energex has therefore applied its own definition of sub-transmission lines for the purposes of the Augex model and considers that this is consistent with the intention of the AER definition.

1.1.1.1.1.1.2 Zone substations

- Energex uses a different definition for zone substations in its normal day to day operations. If Energex was to adopt the Reset RIN definitions, all of its 33/11 kV substations would not be classed as zone substations. This appears contrary to the intended operation of the model to have a clear separation of elements with different cost structures and growth drivers.
- Energex has therefore applied its own definition relating to zone substations for the purposes of the Augex model and considers that this is consistent with the intention of the AER definition.

1.1.1.1.2 Network segments composition

- The Augex model requires that the segment groups established by the AER be disaggregated into network segments. The network segments must reflect the broad grouping of network components where the same planning and operating processes would be applied, where they have a similar network topology and a similar utilisation.
- Energex has applied this approach in disaggregating segment groups into network segments for the purposes of the Augex model. All network segments, by segment group, are listed in Table 4.12.3.

Table 4.12.3 – Augex network segments

Segment group	Network segment
Sub-transmission lines	110 & 132 kV Feeders OH Radial
	110 & 132 kV Feeders UG DCCT Radial
	110 & 132 kV Feeders OH DCCT Radial
	110 & 132 kV Feeders OH 3CCT Mesh
	110 & 132 kV Feeder UG Mesh Dual Source
	110 & 132 kV Feeder OH Mesh Dual Source
	33 kV Feeders UG Radial
	33 kV Feeders OH Radial
	33 kV Feeders UG DCCT Radial
	33 kV Feeders OH DCCT Radial
	33 kV Feeders UG 3CCT Mesh
	33 kV Feeders OH 3CCT Mesh
	110 & 132 kV Feeders OH Radial (zero growth)
	110 & 132 kV Feeders UG DCCT Radial (zero growth)
	110 & 132 kV Feeders OH DCCT Radial (zero growth)
	110 & 132 kV Feeders OH 3CCT Mesh (zero growth)
	110 & 132 kV Feeder UG Mesh Dual Source (zero growth)
	110 & 132 kV Feeder OH Mesh Dual Source (zero growth)
	33 kV Feeders UG Radial (zero growth)
	33 kV Feeders OH Radial (zero growth)
	33 kV Feeders UG DCCT Radial (zero growth)
	33 kV Feeders OH DCCT Radial (zero growth)
	33 kV Feeders UG 3CCT Mesh (zero growth)
	33 kV Feeders OH 3CCT Mesh (zero growth)
Sub-transmission substations and sub-transmission switching stations	Bulk Supply Substation with 2 transformers
	Bulk Supply Substation with 3 transformers
	Bulk Supply Substation with 2 transformers (zero growth)
	Bulk Supply Substation with 3 transformers (zero growth)
Zone substations	Zone Substation with 1 transformer
	Zone Substation with 2 transformers
	Zone Substation with 3 transformers
	Direct Transformation Substation with 2 transformers
	Direct Transformation Substation with 3 transformers
	Zone Substation with 1 transformer (zero growth)
	Zone Substation with 2 transformers (zero growth)
	Zone Substation with 3 transformers (zero growth)
	Direct Transformation Substation with 2 transformers (zero growth)
	Direct Transformation Substation with 3 transformers (zero growth)
High voltage feeders - CBD	CBD 2 Feeder mesh
	CBD 3 Feeder mesh
	CBD 2 Feeder mesh (zero growth)
	CBD 3 Feeder mesh (zero growth)
High voltage feeders - urban	Urban radial
	Urban radial (zero growth)
High voltage feeders - short rural	Rural radial
	Rural radial (zero growth)
Distribution substations - CBD (including downstream LV network)	Distribution Substation CBD – 150kVA to 315kVA
	Distribution Substation CBD – 500kVA
	Distribution Substation CBD – 750kVA
	Distribution Substation CBD – 1000kVA
	Distribution Substation CBD – 1500kVA
Distribution substations - urban (including downstream LV network)	Distribution Substation Urban – ≤25kVA
	Distribution Substation Urban – 30kVA to 63kVA
	Distribution Substation Urban – 75kVA to 100kVA
	Distribution Substation Urban – 150kVA to 315kVA
	Distribution Substation Urban – 500kVA
	Distribution Substation Urban – 750kVA
	Distribution Substation Urban – 1000kVA
	Distribution Substation Urban – 1500kVA
Distribution substations - short rural (including downstream LV network)	Distribution Substation Rural – ≤25kVA
	Distribution Substation Rural – 30kVA to 63kVA
	Distribution Substation Rural – 75kVA to 100kVA
	Distribution Substation Rural – 150kVA to 315kVA
	Distribution Substation Rural – 500kVA

	Distribution Substation Rural – 750kVA
	Distribution Substation Rural – 1000kVA
	Distribution Substation Rural – 1500kVA

- Broadly, the segments groups are disaggregated based on a range of parameters, being:
  - Operating voltage
  - Network topology
  - Overhead and underground construction
  - Demand growth
  - Capacity

This is discussed in further detail below.

1.1.1.1.2.1 Sub-transmission lines

- The AER requires reporting against sub-transmission lines as one segment group. The following sections discuss the disaggregation and composition of each network segment of this segment group.

1.1.1.1.2.1.1 Definition and reasoning for composition

- Energex disaggregated the network group into 24 unique network segments. The segments were disaggregated based on the following four parameters:
  - Operating voltage
  - Network topology
  - Overhead and underground construction
  - Demand growth

Operating voltage

- Energex has disaggregated sub-transmission lines based on the following voltage categories:
  - 110 & 132 kV
  - 33 kV
- The voltage of assets has a material impact on the augmentation unit cost and capacity factors required by the Augex model.

Network topology

- Network topology has a material impact on the capacity factor required by the Augex Model and was therefore considered an appropriate basis on which to disaggregate this segment group, in line with AER requirements. Energex therefore reviewed its sub-transmission network and defined four network topologies. Each category was internally consistent in relation to how the network is operated and the augmentation approach should additional capacity be required. This review was undertaken using the PSS/E and PSS/SINCAL models used for modelling and planning the network.

- Energex has disaggregated sub-transmission lines based on the following four topology categories:
  - Single radial feeder
  - Double radial feeder
  - Triple radial feeder
  - Mesh/complex feeders
- A single radial feeder connects a sub-transmission substation or switching station to another sub-transmission substation or zone substation. Loss of the feeder results in total loss of supply downstream.
- A double radial feeder includes two separate lines that connect a sub-transmission substation or switching station to another sub-transmission substation or zone substation. Loss of a feeder does not result in total loss of supply downstream, but may result in partial loss of supply and leaves the network vulnerable to other events.
- A triple radial feeder includes three separate lines that connect a sub-transmission substation or switching station to another sub-transmission substation or zone substation. Loss of a feeder does not result in total loss of supply downstream, but will change the power flows in the remaining feeders.
- Mesh/Complex (Mesh) feeders include multiple feeders from multiple sources connecting to a substation such that the substation can be supplied from either source. Loss of a feeder does not result in loss of supply downstream, but will change the power flows in the remaining feeders.

Overhead and underground construction

- Energex also disaggregated sub-transmission lines into underground and overhead segments. The construction of assets as either overhead or underground has a material impact on augmentation unit costs required for the Augex model.
- Disaggregation between overhead and underground segments was based on the total length. If the existing network was greater than 50% overhead, it was assumed that future augmentation would be overhead. Likewise, if the existing network was greater than 50% underground, it was assumed that future augmentation would be underground.

Demand growth

- The network segments were also disaggregated by demand growth, as the Augex model is highly sensitive to the demand growth rate factor. Zero growth segments include assets with a forecast growth below zero per cent.

1.1.1.1.2.1.2 Boundary issues

- Energex did not identify any significant boundary issues relating to the sub-transmission network. All take over points between sub-transmission and HV feeders (distribution) are well defined and consistently specified as a switch or disconnector.

1.1.1.1.2.2 Sub-transmission and Zone substations

- For substations the AER requires reporting against two segment groups, being:
  - Sub-transmission substations and sub-transmission switching stations
  - Zone substations
- The following sections discuss how Energex defined these segment groups and the composition of each network segment within these segment groups.

1.1.1.1.2.2.1 Definition and reasoning for composition

- Energex disaggregated the two network groups into 14 unique network segments:
  - four network segments for sub-transmission substations and sub-transmission switching stations, which included bulk supply substations
  - ten network segments for zone substations.
- The segments were disaggregated based on the following parameters:
  - Operating voltage
  - Network topology
  - Demand growth

Operating Voltage

- The operating voltage of the substations has a material impact on augmentation unit cost, capacity factor and utilisation threshold parameters of the Augex model and was therefore considered an appropriate basis on which to disaggregate this segment group, in line with AER requirements.
- The zone substations segment group was therefore disaggregated into zone substations (33/11 kV) and direct transformation substations (132/11 kV or 110/11 kV).
- The sub-transmission substations and sub-transmission switching stations segment group included only sub-transmission substations (132/33 kV or 110/33 kV) and was not disaggregated by operating voltage.

Network topology

- The number of transformers in a substation has a material impact on the capacity factor and utilisation threshold parameters of the Augex model and was therefore considered an appropriate basis on which to disaggregate this segment group, in line with AER requirements.
- Energex disaggregated sub-transmission lines based on the following three topology categories:
  - Single transformer substations
  - Double transformer substations
  - Triple transformer substations
- A single transformer substation connects the sub-transmission network to the next voltage level through one transformer. Loss of the transformer results in total loss of supply downstream.
- A double transformer zone substation connects the sub-transmission network to the next voltage level through two transformers operating in parallel. Loss of a transformer does not result in total loss of supply downstream, but may result in partial loss of supply which requires transfers or generators to restore.
- A triple transformer zone substation connects to the sub-transmission network to the next voltage level through three transformers operating in parallel. Loss of a transformer does not result in total loss of supply downstream, but may result in partial loss of supply which requires transfers or generators to restore.

Demand growth

- The network segments were also disaggregated by demand growth. This was required due to high sensitivity of the Augex model to the demand growth factor. Zero growth segments include assets with forecast growth below zero per cent.

1.1.1.1.2.2.2 Boundary issues

- A boundary issue relating to the zone substation network segments was that typical zone substation projects can include works related to additional network segments. This may include:
  - The construction of sub-transmission lines to connect the primary side of the transformer to the sub-transmission network. This was considered a cost associated with a substation as the work would not otherwise be undertaken and was therefore, allocated to zone substations.
  - 11 kV feeder augmentation works that may be undertaken as part of the project scope. The cost/MVA allocated under the Augex model assumes minimal 11 kV feeder works i.e. only the costs associated with diverting existing HV feeders into the new substation. This was considered a cost associated with a substation as the work would not otherwise be undertaken.

- Energex has addressed these issues through the development of network segments including the augmentation unit costs and capacity factors respectively.

1.1.1.1.2.3 HV feeders

- For HV feeders the AER required reporting against four segment groups, being:
  - High voltage feeders - CBD
  - High voltage feeders - urban
  - High voltage feeders - short rural
  - High voltage feeders - long rural
  - The following sections discuss how Energex has defined the segment groups and the composition of each network segment.

1.1.1.1.2.3.1 Definition and reasoning for composition

- The network segmentation of HV feeders was developed on the basis of the type of augmentation that would be applied in each case and the construction methodology associated with the area.

- Energex initially defined HV feeder segment groups based on feeder categories for CBD, urban and rural, as specified in the Service Target Incentive Scheme (STPIS). Energex does not have any long rural HV feeders.

- The segments were further disaggregated based on the following parameters:
  - Demand growth
  - Network topology

Demand growth

- The network segments were disaggregated by demand growth, as the Augex model is highly sensitive to the demand growth rate factor. Zero growth segments include assets with a forecast growth below zero per cent.

Network topology

- CBD feeders were also disaggregated into additional network segments to account for the complexity of the network and the degree to which it is meshed. Urban and short rural segment groups were not disaggregated further. The network topology is set out in Table 4.12.4.

Table 4.12.4 - HV feeder topology

Network topology	Description	Typical Augmentation
Rural radial	Rural construction will be an almost entirely overhead network.	Typical augmentation will be a new feeder with overhead construction and load transfers between adjacent feeders to balance network loading.
Urban radial	Urban construction will be a mix of overhead and underground network.	Typical augmentation will be a new feeder with a mix of overhead and underground construction and load transfers between adjacent feeders to balance network loading.
CBD 2 Feeder mesh	Underground construction	Typically augmented with an additional feeder to create a 3 feeder mesh when threshold is reached.
CBD 3 Feeder mesh	Underground construction.	Typically augmented with an additional 3 feeder mesh when threshold is reached.

1.1.1.1.2.3.2 Boundary issues

- Energex did not identify any boundary issue relating to the HV feeder network segments that are additional to those discussed above.

1.1.1.1.2.4 Distribution Substations (including LV network)

- For distribution substations the AER established four segment groups, being:
  - Distribution substations - CBD (including downstream LV network)
  - Distribution substations - urban (including downstream LV network)
  - Distribution substations - short rural (including downstream LV network)
  - Distribution substations - long rural (including downstream LV network)
  - The following sections discuss how Energex defined the segment groups and the composition of each network segment within those groups.

1.1.1.1.2.4.1 Definition and reasoning for composition

- Energex defined distribution substation segment groups largely based on feeder categories for CBD, urban and rural, as specified in the STPIS. Energex does not have any long rural distribution substations.
- Energex disaggregated the segment groups based on distribution transformer capacity in kVA:

– ≤25 kVA distribution transformers (Only Urban and Rural)
– 30 kVA to 63 kVA distribution transformers (Only Urban and Rural)
– 75 kVA to 100 kVA distribution transformers (Only Urban and Rural)
– 150 kVA to 315 kVA distribution transformers
– 500 kVA distribution transformers
– 750 kVA distribution transformers
– 1000 kVA distribution transformers
– ≥1500 kVA distribution transformers

- The network segmentation for Distribution Substations and LV was based on the current construction standards and the population of existing transformers.

1.1.1.1.2.4.2 Boundary issues

- Energex did not identify any boundary issues with distribution substation and LV networks.

1.1.1.2 Augmentation unit cost

- The AER requires Energex to provide an augmentation unit cost used to define the cost of additional capacity that is added to the system through the Augex model. The term augmentation unit cost is italicised in this section to indicate the unit costs derived for the purposes of the Augex model, as opposed to project and program estimates derived by Energex as part of its normal augmentation planning processes.
- In order to calculate the augmentation unit cost for each network segment the following process was applied:
  – Each project was assigned to an Augex model network segment.
  – Cost and capacity added for each asset (or project for historical data) was then used to calculate the augmentation unit cost per MVA for that asset.
  – The augmentation unit cost per MVA for a network segment was the average augmentation cost per MVA for all of the assets within the network segment.
- Energex developed a generic unit cost for each network segment through its estimating system.

1.1.1.2.1 Methodology, data sources and assumptions

1.1.1.2.1.1 Sub-transmission and zone substation network segments

- Energex applied the same approach to all sub-transmission network segments, being the network segments in the following AER segment groups:

- sub-transmission lines
- sub-transmission substations and sub-transmission switching stations
- zone substations

1.1.1.2.1.1.1 Forecast methodology

- To cater for the network average nature of the network segments, 12 separate generic project scopes were developed and assigned a unit cost and capacity. The project types and high level scopes of work are set out in Table 4.12.5.

Table 4.12.5 - Project scopes overview

Project type	Overview of key scope items
110/132 kV SCCT OH line 180MVA	13 km of feeder with 2 x feeder bays (one at each sub), including all civil works
110/132 kV SCCT UG line 240MVA	3.5 km of feeder with 2 x feeder bays (one at each sub), including all civil works
33 kV SCCT OH line 40MVA	9 km of feeder and 1 x feeder bay, including all civil works
33 kV SCCT UG line 40MVA	4 km of feeder and 1 x feeder bay, including all civil works
Rural Zone sub upgrade 33/11 (8MVA)	Skid substation, including all civil works, 4km OH 11kV feeder works and 2km OH 33kV feeder works
Urban Zone Sub upgrade 33/11 (25MVA)	2nd module, including all civil works, 2 km OH 11 kV feeder works, 2km UG 11kV feeder works, 1 km UG DCCT 33 kV feeder works and 33 kV feeder tail cutover
Urban zone Sub upgrade 110/11 (30MVA)	30MVA 110/11kV transformer, 110 kV and 11 kV ID bus (masonry building), including all civil works, 4km OH 11kV feeder works and 110 kV UG feeder tails cutover
Rural zone Sub upgrade 110/11 (30 MVA)	30 MVA 110/11kV transformer, 110 kV OD and 11kV ID prefab bus, including all civil works, 4km OH 11kV feeder works, 110 kV OH feeder tails cutover
Urban zone Sub upgrade 110/11 (60 MVA)	60 MVA 110/11/11kV transformer, 110 kV and 11kV ID bus (masonry building), including all civil works, 4km UG 11kV feeder works, 110 kV UG feeder tails cutover
Urban Bulk Sub upgrade 110/33 (80 MVA)	80 MVA 110/33 kV transformer, 110kV and 33 kV ID bus (masonry building), including all civil works, 110 kV and 33 kV UG feeder tails

	cutover
Rural Bulk Sub upgrade 110/33 (80 MVA)	80 MVA 110/33 kV transformer, 110 kV OD and 33kV ID prefab bus, including all civil works, 110 kV and 33 kV OH feeder tails cutover
Urban Bulk Sub upgrade 110/33 (120 MVA)	120 MVA 110/33 kV transformer, 110 kV and 33 kV ID bus (masonry building), including all civil works, 110kV and 33 kV UG feeder tails cutover

- Each network asset identified in Reset RIN tables 2.4.1 and 2.4.3 was allocated to a project type. The unit cost was calculated on the average unit cost of assets comprising the network segment.

1.1.1.2.1.1.2 Historical methodology

- A sample of 64 Planning Approval Reports was reviewed for the network segments of sub-transmission lines, sub-transmission substation, and zone substation to estimate the historic augmentation unit cost. The sample size for each network segment is shown in Table 4.12.6. The list of projects reviewed contained projects with project expenditure greater $5 million that were commissioned between 2009/10 and 2013/14.

Table 4.12.6 - Review of past projects

Segment group	Number of projects reviewed
Sub-transmission Lines	14
Sub-transmission Substations	8
Zone Substations	42

1.1.1.2.1.1.3 Sources

- Standard cost estimation used for forecast augmentation unit cost was sourced from the Ellipse Estimation Systems and modules, particularly the Compatible Units and Estimation Modules.

- Historic parameters were recorded from Planning Approval Reports.

1.1.1.2.1.1.4 Assumptions

- Typical project scopes developed reflect the expected augmentations in the forthcoming regulatory control period.

1.1.1.2.1.2 HV feeder network segments

1.1.1.2.1.2.1 Forecast methodology

- The list of projects developed and high level scopes of work are shown in Table 4.12.7. These scopes were apportioned in terms of capacity added and cost contributions to each Augex model network segments for the purpose of deriving unit costs.

Table 4.12.7 - Project scopes overview

Project type	Overview of key scope items
11kV feeder tie	1.5 km of new underground cable, switchgear and associated civil works.
11kV CBD mesh add new feeder to 2fdr mesh	1.2km of new underground cable and associated civil works.
11kV CBD mesh works - new 3fdr mesh	1.2km of new underground cable and associated civil works.
11kV CBD mesh works - cutovers	1.2km of new underground cable and associated civil works.
11kV new overhead feeder	0.9km new underground cable, 1km of reconductored overhead, 1km new overhead, associated switchgear and civil works
11kV new underground feeder	1.8km new underground cable, 1km of reconductored overhead, switchgear and civil works.

1.1.1.2.1.2.2 Historical methodology

- An analysis of a sample of 98 projects was undertaken to estimate historic augmentation unit cost. Projects included in the review consisted of projects commissioned between 2008 and 2013 where the project cost was greater than $500,000 and one or more of the following system events were logged by NetPlan:
  - 11 kV Load transfer;
  - 11 kV feeder rating change; or
  - New 11 kV feeder.

- HV feeder projects include tie feeders that enable transfer between feeders but do not add to the network capacity for the purposes of the Augex model. This issue was recognised by the AER in its Augmentation Model Handbook8.

1.1.1.2.1.2.3 Sources

- Standard cost estimation was sourced from the Ellipse Estimation Systems and modules, particularly the Compatible Units and Estimation Modules. The Plant Rating9 Manual was used to identify typical additional capacity added corresponding with each of the project scopes.

1.1.1.2.1.2.4 Assumptions

- Typical project scopes were developed to be reflective of the expected augmentations in the forthcoming regulatory control period.

1.1.1.2.1.3 Distribution substations including LV network segments

1.1.1.2.1.3.1 Forecast methodology

- The methodology applied to forecast unit costs for distribution substation and LV network segments used a standard cost estimate generated through the Ellipse Estimation System. The cost per MVA for each segment was determined by taking the weighted average cost per MVA installed for each Standard Estimate under the applicable network segment. Table 4.12.8 sets out the standard estimates applicable for each network segment.

Table 4.12.8 – Standard Estimates overview

Network Segment	Standard Estimate Description
≤25kVA Transformers	Upgrade Transformer from 25kVA 3 Phase TO 100kVA 3 Phase
	Upgrade Transformer from 25kVA 3 Phase TO 200kVA 3 Phase
	Upgrade Transformer from 25kVA 3 Phase TO 315kVA 3 Phase
	Upgrade Transformer from 25kVA 3 Phase TO 63kVA 3 Phase
30kVA to 63kVA Transformers	Upgrade Transformer from 63kVA 3 Phase TO 100kVA 3 Phase
	Upgrade Transformer from 63kVA 3 Phase TO 200kVA 3 Phase
	Upgrade Transformer from 63kVA 3 Phase TO 315kVA 3 Phase
75kVA to 100kVA Transformers	Upgrade Transformer from 100kVA 3 Phase TO 200kVA 3 Phase
	Upgrade Transformer from 100kVA 3 Phase TO 315kVA 3 Phase
150kVA to 315kVA Transformers	Upgrade Transformer from 200kVA 3 Phase TO 315kVA 3 Phase
	Upgrade Padmount Transformer from 315kVA 3 Phase TO 500kVA 3 Phase RECTANGLE
	Upgrade Padmount Transformer from 315kVA 3 Phase TO 500kVA 3 Phase SQUARE
	Upgrade Padmount Transformer from 315kVA 3 Phase to 750kVA 3 Phase SQUARE
	Upgrade Padmount Transformer from 315kVA 3 Phase TO 750kVA 3 Phase

[8] Australian Energy Regulator, AER augmentation model handbook, November 2013 section 5.1.3
[9] Energex, Plant Rating Manual, January 2008

	RECTANGLE
	Upgrade Padmount Transformer from 315kVA 3 Phase TO 1000kVA 3 Phase RECTANGLE
	Upgrade Padmount Transformer from 315kVA 3 Phase TO 1000kVA 3 Phase SQUARE
500kVA Transformers	Upgrade Transformer from 500kVA 3 Phase TO 750kVA 3 Phase SQUARE
	Upgrade Transformer from 500kVA 3 PH TO 750kVA 3 Phase RECTANGLE
	Upgrade Transformer from 500kVA 3 Phase TO 1000kVA 3 Phase SQUARE
	Upgrade Transformer from 500kVA 3 Phase TO 1000kVA 3 Phase RECTANGLE
750kVA Transformers	Upgrade Transformer from 750kVA 3 Phase TO 1000kVA 3 Phase RECTANGLE
	Upgrade Transformer from 750kVA 3 Phase TO 1000kVA 3 Phase SQUARE
1000kVA Transformers	Upgrade Ground Transformer from 1000kVA 3 Phase TO 1500kVA 3 Phase
1500kVA Transformers	Install a New 11kV – Ground Transformer 1500kVA (Dry Type)

1.1.1.2.1.3.2 Historical methodology

- Energex undertook a review of 227 historical distribution transformer and LV augmentation projects and used the weighted average to determine the historical augmentation unit cost. Projects included in the review consisted of distribution transformers projects commissioned between 2008 and 2013 that could be cross referenced to a capacity increase in NFM.

1.1.1.2.1.3.3 Sources

- Historical data was sourced from Ellipse project reports cross referenced against asset data held in NFM.
- Standard cost estimation was sourced from the Ellipse Estimation Systems and modules, particularly the Compatible Units and Estimation Modules. The Plant Rating10 Manual was used to identify typical additional capacity added corresponding with each of the project scopes.

1.1.1.2.1.3.4 Assumptions

- Typical project scopes reflect the expected augmentations in the forthcoming regulatory control period.

1.1.1.2.2 Relationship to historical augmentation

1.1.1.2.2.1 Sub-transmission network segments

- There was some variability in augmentation unit cost compared to historical augmentation projects, which was due to the large differences between the scope of historical projects and the typical augmentations used in the Augex model. This effect was exaggerated by the relatively small populations of each network segment, and was most obvious when considering sub-transmission lines, which have a particularly high variability due to:

[10] Energex, Plant Rating Manual, January 2008

- surroundings (population density).
- environments (imposing requirements relating to vegetation and wildlife).
- traffic conditions (imposing requirements relating to traffic control, under-boring and time of day where works can be carried out).
- soil conditions, specific council guidelines and community requirements (imposing requirements relating to undergrounding).
- changes in legislation and external approval requirements over time.

- Route length which the Augex model is not able to account for (it only considers unit cost as $/MVA). Assumptions of typical route length for sub-transmission lines are set out in Table 4.12.3 of section 1.1.1.1.2.
- Energex takes all of these factors into account by producing bottom-up estimate for each sub-transmission projects as part of the normal planning process.
- Energex takes all of these factors into account by producing bottom-up estimate for each sub-transmission projects as part of the normal planning process.

1.1.1.2.2.2 HV feeders

- There was some variability in augmentation unit costs compared to historical augmentation projects, which was due to the differences in project scopes (including route length); and the mix of 11 kV project types within the program. Specifically, the number of tie feeder projects has a large impact on the augmentation unit cost as they do not add network capacity for the purposes of the Augex model.

1.1.1.2.2.3 Distribution substations including LV

- There was some variability in augmentation unit costs compared to historical augmentation projects, because forecast augmentation unit cost used in the Augex model was based on standard estimates of typical augmentation. However, when these types of augmentations typically occur network limitations are usually packaged into larger projects to improve overall efficiency. This can lead to variation between historic and forecast augmentation unit cost.

1.1.1.2.3 Possibility of double counting

- The possibility of double counting the augmentation unit cost was minimised by clearly defining network segments (as set out in section 1.1.1.1.2) and ensuring that the inputs into augmentation unit cost only included those associated with the network segment.

1.1.1.2.4 Verification of parameters

- Energex considers that augmentation unit cost are a reasonable estimate for each network segment the following reasons:
  - augmentation unit costs provided were commensurate with the network average approach implemented in the Augex model.
  - The data used for the calculation of the parameters was sourced from business as usual systems used by Energex to plan network augmentation. The data in these systems is reviewed on a regular basis by the network capital strategy and planning group.

- Parameters were calculated in accordance with the Augex Model Handbook guidelines.

1.1.1.3 Capacity factors

- The AER requires Energex to provide a capacity factor that is used to define the amount of additional capacity that is added to the system in the Augex model. Where actual historical data is not available, the AER allows the derivation of the capacity factor from the normal practices of network planning or policy decisions to increment capacity in standard steps. The capacity factor must be greater than zero.

- The Augex model requires an average capacity factor for each network segment, implying that a similar solution is applied to all network limitations. It is important to note that Energex does not take this approach when determining its augmentation expenditure requirements, instead it prepares a bottom up forecasts based on detailed option analysis.

- The Capacity factor represents the capacity added, as a percentage, of the capacity of the existing network segment being augmented11. The formula for calculating the capacity factor is specified by the AER and is shown below:

$$\text{Capacity Factor} = \frac{\text{Capacity Added}}{\text{Capacity Requiring Augmentation}}$$

Where:

- Capacity Added is the amount of capacity added to the network through new assets being installed

- Capacity Requiring Augmentation is the amount of capacity provided by the asset currently on the network which requires augmentation.

1.1.1.3.1 Methodology, data sources and assumptions

1.1.1.3.1.1 Sub-transmission network segments

- Energex applied the same methodology to all sub-transmission network segments, being the network segments in the following AER segment groups:
  - Sub-transmission lines
  - Sub-transmission substations and sub-transmission switching stations
  - Zone substations
  - A different methodology was applied to the derivation of forecast and actual parameters, as set out below.

[11] AER augmentation model handbook, November 2013, section 4.4.2

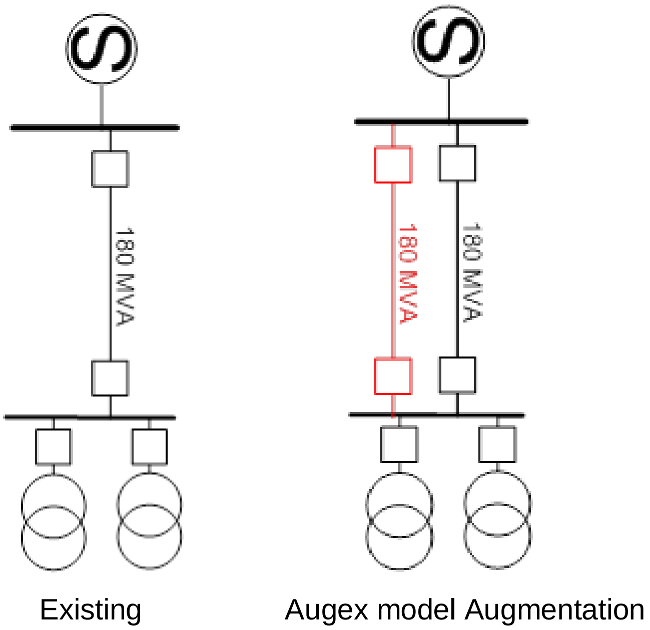
1.1.1.3.1.1.1 Forecast parameter methodology

- Energex calculated the forecast capacity factor for network segments in the above segment groups using standard planning processes and incremental unit increases added during normal augmentation projects

Single radial feeder

- The Augex model augmentation involves connecting a second feeder in parallel between the two substations. Figure 1 shows the topology before and after augmentation.

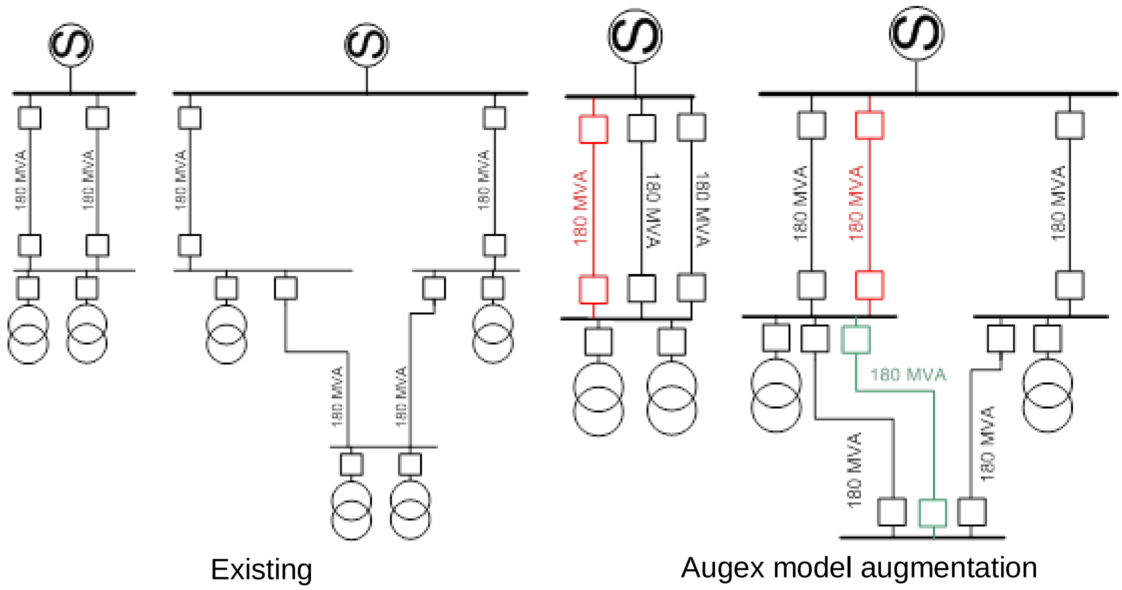
Figure 1 - Single radial feeder showing Augex augmentation



Double radial feeder

- Augex model augmentation involves connecting a third feeder in parallel between the two substations. Figure 2 shows the various arrangements of this topology that are included in this network segment and how these segments would be augmented.

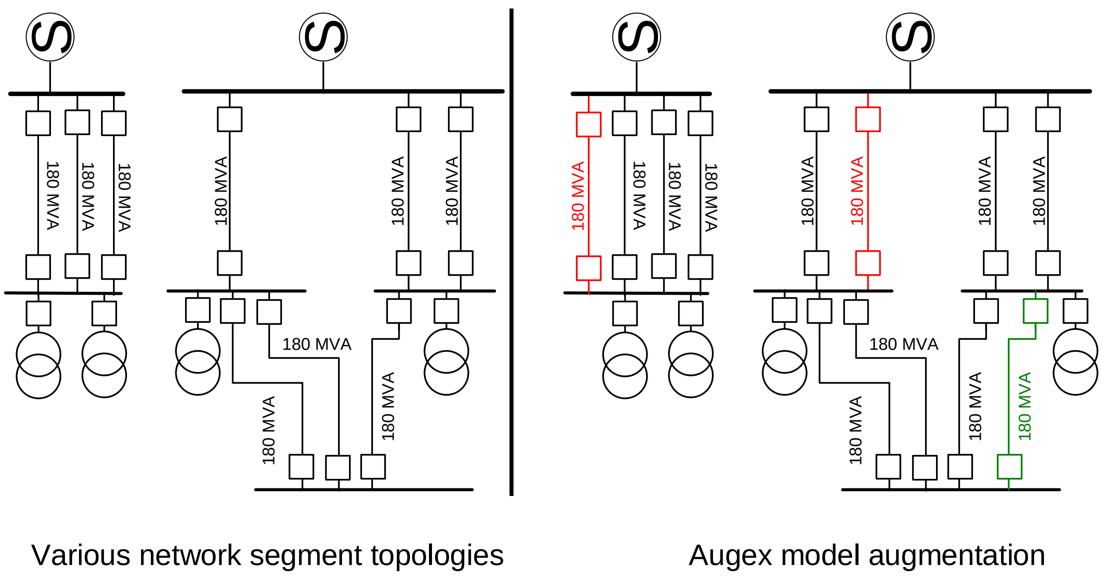
Figure 2 - Double radial feeder variations showing Augex augmentation



Triple mesh feeder

- Augex model augmentation involves connecting a fourth feeder in parallel between the two substations. shows the various arrangements of this topology that are included in this network segment and how these segments would be augmented.

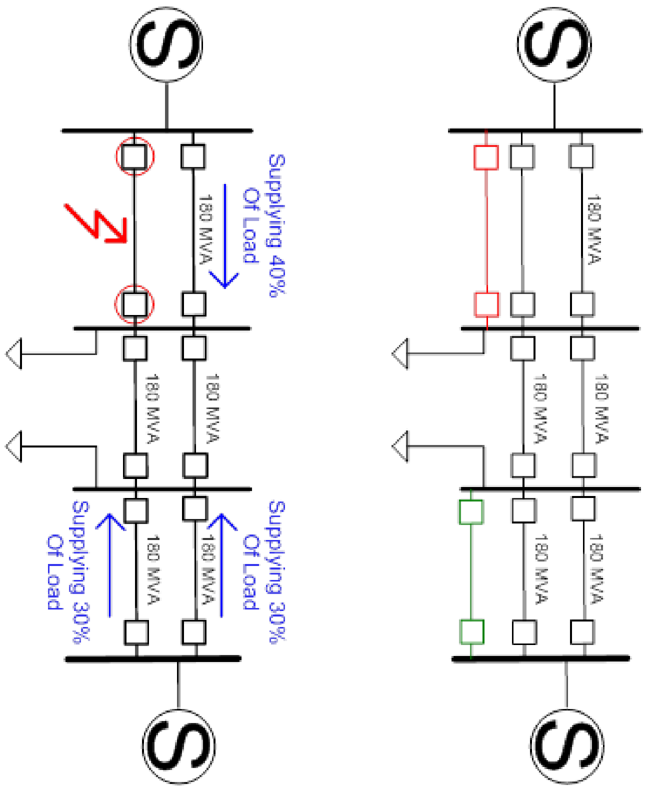
Figure 3 - Triple mesh feeder variations showing Augex model augmentation



Mesh/complex feeders

- Augex model augmentation involves connecting an additional feeder in parallel between each of the sources and the substation. Figure 4 shows the various arrangements of this topology that are included in this network segment and how these segments would be augmented.

Figure 4 - Mesh feeder variations showing Augex model augmentation



Example of mesh feeder arrangement

Example of mesh feeder Augex model augmentation

Single transformer substations

- Augex model augmentation involves connecting an additional transformer to provide redundancy and additional capacity

Double transformer substations

- Augex model augmentation involves connecting an additional transformer to provide redundancy and additional capacity.

Triple transformer substations

- Augex model augmentation involves connecting an additional transformer to the network, establishment of a new substation, or replacing multiple transformers with higher capacity units.

1.1.1.3.1.1.2 Historical parameter methodology

- A sample of 64 Planning Approval Reports was reviewed to establish the asset utilisation at the time of augmentation for the network segments of sub-transmission lines, sub-transmission substation, and zone substation. The sample size for each network segment is shown in Table 4.12.9. The list of projects reviewed contained projects with project expenditure greater $5 million that were commissioned between 2009/10 and 2013/14.

Table 4.12.9 - Review of past projects

Segment group	Number of projects reviewed
Sub-transmission Lines	14
Sub-transmission Substations	8
Zone Substations	42

1.1.1.3.1.1.3 Sources

- Forecast capacity added was sourced from Energex's Network Building Blocks12. This manual includes standard capacities for sub-transmission network assets.
- Historical capacity added was sourced from planning approval reports.

1.1.1.3.1.1.4 Assumptions

- Existing and proposed network capacity does not vary between project approval and project commissioning.

1.1.1.3.1.2 HV Feeder network segments

1.1.1.3.1.2.1 Forecast and historic parameter methodology

- Energex undertook a review of 98 historical HV feeder augmentation projects to determine the capacity factors, and capacity added through these projects, at the time of replacement. Energex utilised historic capacity factor data for HV feeder network segments, where sufficient historic data was available.
- The sample size for each network segments is shown in Table 4.12.10. Projects included in the review consisted of projects commissioned between 2008 and 2013 where the project cost was greater than $500,000 and where one or more of the following system events were logged by NetPlan:
  - 11 kV Load transfer

[12] Energex document 00303 – Standard Network Building Blocks, 2012

- 11 kV feeder rating change
- New 11 kV feeder

Table 4.12.10 - Review of past projects

Segment group	Number of projects reviewed
High voltage feeders - CBD	5
High voltage feeders - urban	61
High voltage feeders - short rural	32

1.1.1.3.1.2.2 Sources

- The NetPlan database was used to provide historic augmentation capacity.

1.1.1.3.1.2.3 Assumptions

- For the HV Feeders - CBD network segment there was little historic data available regarding the two feeder mesh network portion of this network segment. Parameters for HV Feeders – CBD are based on the historic three feeder mesh values.

1.1.1.3.1.3 Distribution transformers (including LV) network segments

- Energex applied the same methodology distribution transformers and low voltage network segments, being the network segments in the following AER segment groups:
  - Distribution substations - CBD (including downstream LV network)
  - Distribution substations - urban (including downstream LV network)
  - Distribution substations - short rural (including downstream LV network)

1.1.1.3.1.3.1 Forecast and historic parameter methodology

- Energex undertook a review of 227 historical distribution transformer and low voltage augmentation projects and used the weighted average to determine the historical and forecast capacity factors. Projects included in the review comprised distribution transformers projects commissioned between 2008 and 2013 that could be cross referenced to a capacity increase in NFM.

1.1.1.3.1.3.2 Sources

- Historic data was sourced from Ellipse project reports cross referenced against asset data held in NFM.

1.1.1.3.1.3.3 Assumptions

- No significant assumptions have been applied in the calculation of capacity factors for distribution transformers and low voltage network segments.

1.1.1.3.2 Relationship to historic augmentation

- The calculation of capacity factor was heavily dependent on the existing asset, network configuration and drivers of augmentation.
- Historic and forecast sub-transmission capacity factors can vary significantly due to:
  – Small sample size of historical projects in each network segment
  – Large variation in ratings of existing feeders
  – Changes in security standards
  – For HV feeders, distribution substations and LV networks historic capacity factors have been used as the forecast parameters.

1.1.1.3.3 Possibility of double counting

- The possibility of double counting the capacity factors was minimised by clearly defining network segments (as set out in section 1.1.1.1.2) and ensuring that the inputs into capacity factor only included those associated with the network segment.

1.1.1.3.4 Verification of parameters

- Energex considers that capacity factors are reasonable estimates for each network segment the following reasons:
  – Capacity factors provided are commensurate with the network average approach implemented in the Augex model.
  – The data used for the calculation of the parameters was sourced from business as usual systems used by Energex to plan network augmentation. The data in these systems is reviewed on a regular basis by the network capital strategy and planning group.
- Parameters were calculated in accordance with the Augex Model Handbook guidelines.

1.1.1.4 Utilisation threshold

- The AER requires Energex to provide the utilisation threshold statistics, mean and standard deviation, for each network segment defined in Reset RIN table 2.4.5. The AER defines the utilisation threshold as the point when assets need to be augmented, that is where the asset will breach reliability standards or exceed the economic point of maximum utilisation13. This section explains the utilisation threshold statistics provided and justifies the approach taken.

- Table 2.4.5 of the Reset RIN requires both historic and forecast utilisation threshold parameters. Section 1.1.1.4.1 details the methodology used to calculate the forecast and historic parameters.

1.1.1.4.1 Methodology, data sources and assumptions

- This section sets out the methodology, data sources and assumptions used to derive the utilisation threshold statistics provided for each network segment defined by Energex in Reset RIN table 2.4.5.

1.1.1.4.1.1 Sub-transmission and zone substation network segments

- Energex applied the same methodology to all sub-transmission network segments, being the segments in the following AER segment groups:
  - Sub-transmission lines
  - Sub-transmission substations and sub-transmission switching stations
  - Zone substations.

1.1.1.4.1.1.1 Forecast parameter methodology

- For each individual network segment, Energex:
  - Extracted the Normal Cyclic Capacity (NCC) from the Load flow models/ERAT2 (feeders) or SIFT (substations) database for system normal conditions.
  - Extracted the emergency cyclic rating (ECC) from SIFT (substations) database as the “N-1 emergency” capacity. The capacity for feeders was considered the same as NCC as there was no ECC for feeders.
  - Applied consistent assumptions to each network segment for the average available transfers and generation as shown in Table 4.12.12.
  - Calculated the utilisation threshold for each network segment using Equation 1 below.
  - Calculated the mean and standard deviation for the data series using Equations 2 and 3 below.

[13] AER augmentation model handbook, November 2013, sections 3.2 and 4.2.2

- Equation 1 below outlines the methodology in obtaining the utilisation threshold:

$$\text{Utilisation Threshold} = \frac{\text{ECC + Average Transfers + Generation}}{\text{NCC}} \times 100\% \text{ ....Eqn 1}$$

$$\frac{N-1\ Capacity + Avg\ Transfers + Max\ S\imath ed}{NC\ Capacity} \times 100\%$$

Where:

- – ECC is the emergency cyclic capacity under outage conditions
- – NCC is the normal cyclic capacity
- – Average Transfers is average transfer capacity available through network switching
- – Generation is the amount of generation capacity available to the asset

- The maximum utilisation threshold based on 50% PoE load was capped at 88%, as Energex plans the network to support 10% PoE load under system normal configuration.
- The utilisation for each asset was calculated and allocated to the data series for the network segment.
- Equations 2 and 3 below outline the methodology used to calculate the mean utilisation threshold and standard deviation for that network segment using the data series:

$$\text{Mean utilisation threshold} = \frac{\sum_1^N \mathrm{UT}}{\mathrm{N}} \text{ ………………………………..……….Eqn 2}$$

$$\text{Utilisation threshold standard deviation} = \sqrt{\frac{\sum(\mathrm{UT}-\overline{\mathrm{UT}})^2}{\mathrm{N}}} \text{……………………..….Eqn 3}$$

Where:

- N is the number of asset in the network segment
- UT is the utilisation threshold of the data point and
- $\overline{\mathrm{UT}}$ is the mean utilisation threshold of the data series.

1.1.1.4.1.1.2 Historic parameter methodology

- A sample of 64 Planning Approval Reports was reviewed for the network segments of sub-transmission lines, sub-transmission substation, and zone substation to establish the asset utilisation at the time of augmentation. The sample size for each network segments is shown in Table 4.12.11. The list of projects reviewed contained projects with project expenditure greater than $5 million that were commissioned between 2009/10 and 2013/14.

Table 4.12.11 - Review of past projects

Segment group	Number of projects reviewed
Sub-transmission Lines	14
Sub-transmission Substations	8
Zone Substations	42

1.1.1.4.1.1.3 Sources

- Energex calculated the utilisation threshold for each feeder using the remaining capacity under an outage condition, plus any available load transfers and generation. The outage condition capacities were obtained from ERAT2, the available load transfers were calculated as a network average based on load flow studies, and the available generation was assumed to be the maximum amount allowed by the Safety Net Targets14.
- Historic parameters were recorded from Planning Approval Reports.

1.1.1.4.1.1.4 Assumptions

- The following assumptions were applied to derive the utilisation threshold statistics:
- Single radial does not apply to CBD substations.
- Double radial and triple radial assume all feeders/transformers have equal impedances and therefore carry an equal share of the load.
- Available transfer capacity and generation assumptions are as described in Table 4.12.12 below:

Table 4.12.12 Transfer and generation capacity assumptions

	Substations			Feeders		
Assumption	**Single**	**Double**	**Triple**	**Single**	**Double**	**Triple**
Urban Zone Average Transfer Capacity	6 MVA	6 MVA	6 MVA	-	-	-
Rural Zone Average Transfer Capacity	1 MVA	1 MVA	1 MVA	-	-	-
Bulk Supply Average Transfer Capacity	N/A	18 MVA	18 MVA	-	-	-

[14] Energex Distribution Authority – Schedule 3

	Substations			Feeders		
Urban allowable generation	4 MVA	4 MVA	4 MVA	4 MVA	4 MVA	2 MVA
Rural allowable generation	10 MVA	10 MVA	10 MVA	10 MVA	10 MVA	5 MVA
Urban Sub-Transmission Lines Average Transfer Capacity	-	-	-	6 MVA	6 MVA	3 MVA
Rural Sub-Transmission Lines Average Transfer Capacity	-	-	-	1 MVA	1 MVA	0.5 MVA
Transmission Lines Average Transfer Capacity	-	-	-	18 MVA	18 MVA	9 MVA

1.1.1.4.1.2 HV feeders network segments

- Energex applied the same methodology to all HV feeder network segments, being the segments in the following AER segment groups:
  - High voltage feeders - CBD
  - High voltage feeders - urban
  - High voltage feeders - short rural
- The approach taken for each segment group was based on the Energex planning standards.

1.1.1.4.1.2.1 Historic and forecast parameter methodology

HV feeders (Urban and short rural)

- A sample of 93 historic projects was reviewed for the segment groups to estimate the historic asset utilisation at the time of augmentation. The sample size for each network segment is shown in Table 4.12.13.

Table 4.12.13 - Review of past projects

Segment group	Number of projects reviewed
High voltage feeders - urban	61
High voltage feeders - short rural	32

- With regard the forecast parameter, Energex determined a target maximum utilisation (TMU) for each 11 kV feeder based on network topology. The TMUs are reported in Energex's DAPR and have historically been 75% for urban and short rural 11 kV feeders.

- Energex recently increased the TMU for urban and short rural 11 kV feeders from 75% to 80% due to an increased focus on 11 kV feeder tie capability. To account for this change in approach, the historic utilisation was increased by 5% to give the forecast utilisation parameter.

HV Feeders (CBD)

- A sample of five historic CBD projects was reviewed to estimate the historic asset utilisation at the time of augmentation of CBD three feeder mesh networks.
- For the CBD three feeder mesh network segment, there was no change in Energex's TMU hence, the historic utilisation threshold was used as the forecast parameter.
- For the CBD two feeder mesh network segment, there was no change in Energex's TMU however, sufficient historic projects were not available to estimate the historic asset utilisation at time of augmentation. The utilisation threshold for this network segment was estimated based the CBD three feeder mesh parameters taking into account the difference in TMUs of three feeder mesh (66% TMU) and two feeder mesh (50% TMU) networks.

1.1.1.4.1.2.2 Sources

- The NetPlan database was used to provide historic utilisation at time of project commissioning.

1.1.1.4.1.2.3 Assumptions

- The following assumptions were applied to derive the utilisation threshold statistics to HV feeders:
  - The difference between new planning TMU and average utilisation threshold will remain the same for radial network segments. The difference between the historic average utilisation threshold from sample projects and the TMU was maintained but increased to reflect the increase in TMU used by Energex for radial feeders.
  - The difference between the planning TMU and average historic utilisation threshold was consistent between CBD three feeder mesh and CBD two feeder mesh network segments.

1.1.1.4.1.3 Distribution transformers (including LV) network segments

- Energex applied the same methodology to all distribution substation network segments, being the segments in the following AER segment groups:
  - Distribution substations - CBD (including downstream LV network)
  - Distribution substations - urban (including downstream LV network)
  - Distribution substations - short rural (including downstream LV network)

1.1.1.4.1.3.1 Methodology

- Energex has not historically recorded the utilisation of time augmentation for distribution substations in a corporate system.

- The mean utilisation threshold for the purposes of the Augex model was therefore provided for distribution transformers and LV network segments based on Energex's Plant Rating Manual. Specifically:

  - The Plant Rating Manual states that the NCC for transformers classified as domestic is 135% of the nameplate rating, and this utilisation threshold was reported for network segments categorised as urban and rural.
  - The Plant Rating Manual states that transformers classified as Commercial and Industrial substations typically utilise dry type transformers that have a NCC rating of 100% of the name plate rating and this was reported for transformers classified in the CBD network segment.

1.1.1.4.1.3.2 Sources

The Energex Plant Rating Manual[15].

1.1.1.4.1.3.3 Assumptions

- The following assumptions were applied to derive the utilisation threshold statistics distribution transformers and low voltage network segments:

- The network segment categorised as urban and rural were domestic customers

- Transformers classified in the CBD network segment were all substations for Commercial and Industrial customers.

1.1.1.4.2 Relationship to historic utilisation

- The utilisation threshold was largely defined by network security standards at the time of project approval. However the approach to determining the utilisation threshold has not materially changed between forecast and historic parameters

1.1.1.4.3 Probability distribution

- Due to the general nature of the Augex model Energex does not see any reason to depart from the normal distribution for the purpose of reporting against the AER's network segments in Reset RIN table 2.4.5.

- Energex does not apply probability distributions when forecasting network augmentation requirements on a business as usual basis, instead it applies more rigorous processes and detailed estimated techniques to ensure the development of robust forecasts, such as a bottom up forecast based on detailed option analysis required to deliver compliance with the Distribution Authority.

[15] Energex, Plant Rating Manual, January 2008

1.1.1.4.4 Relationship to internal or external planning criteria

- The utilisation threshold parameters provided in Reset RIN table 2.4.5 were calculated based on internal planning criteria.

- The Augex Model Handbook required that asset utilisation be provided based on normal cyclic ratings using 50% PoE loads16. However, Energex typically uses 50 PoE load forecasts with emergency ratings under outage conditions and uses 10% PoE load forecasts with normal cyclic ratings for normal conditions. These differences were taken into account when calculating the asset utilisation parameters.

- Further, Energex does not apply statistical distributions when calculating utilisation of assets. The normal planning process undertaken is described in Energex's DAPR.

1.1.1.4.5 Verification of parameters

- Energex considers that the methodology applied and the assumptions made are suitable for use in the Augex model for the following reasons:
  - Parameters provided were commensurate with the network average approach implemented in the Augex model.
  - The data used for the calculation of the parameters was sourced from business as usual systems used by Energex to plan network augmentation. The data in these systems is reviewed on a regular basis by the network capital strategy and planning group.
- Parameters were calculated in accordance with the Augex Model Handbook guidelines.

12.3 Estimated Information

- All data provided in Reset RIN table 2.4.5 is Estimated Information due to the process required to provide data consistent with the Reset RIN requirements.

12.3.1 Justification for Estimated Information

- Energex does not record project information in the required categories, therefore data was provided based on a sample of recently completed projects.

12.3.2 Basis for Estimated Information

- All estimated data has been compiled based on requirements set out in the AER's augmentation model handbook, November 2013. In addition to this, the AER requires the average unit cost of augmentation ($/MVA) to be presented as real June 2015.

- The escalation factors used are set out in Table 4.12.14. The escalation factors were calculated from the ABS values for CPI based on the eight capital city average.

[16] AER augmentation model handbook, November 2013, sections 5.1.2 and 5.1.6

Table 4.12.14 Summary of escalation factors

Financial Year	Escalation Factor
2002 FY	1.419
2003 FY	1.389
2004 FY	1.344
2005 FY	1.31
2006 FY	1.281
2007 FY	1.244
2008 FY	1.215
2009 FY	1.165
2010 FY	1.137
2011 FY	1.105
2012 FY	1.069
2013 FY	1.052
2014 FY	1.029
2015 FY	1

12.4 Explanatory notes

- Energex does not have any HV feeders or distribution substations classified as long rural.
- Historic parameters for zero growth segments are based on normal growth segments, i.e. 33 kV Feeders UG Radial (minimal growth) shares the same historic parameters as 33 kV Feeders UG Radial.

13 BoP 2.4.6 – Capex and Net Capacity Added by Segment Group

This Basis of Preparation relates to Table 2.4.6 as set out in worksheet 2.4 – Augex Model.

RIN Table 2.4.6 includes both historic and forecast data. This BoP applies only to projects with expenditure between 2009-10 and 2013-14.

The AER requires Energex to provide the following information relating to table 2.4.6 – Capex and net capacity added by segment group:

- **Capex ($000's, real June 2015)**
- **Net capacity added (MVA) for all purposes**

All data was estimated.

13.1 Consistency with Reset RIN Requirements

Table 13.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 13.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
If an asset of Energex does not exactly match the definitions in appendix F, Energex must include the asset in the regulatory template that most closely reflects its primary nature. Energex must clearly label such assets and note such assets in the basis of preparation document(s).	Refer section 13.3.1 - Assumptions
The type of net capacity should match the various types of rating indicated in regulatory templates 2.4.1 to 2.4.4 (on regulatory template 2.4). For example, for zone substations: i. type 1 reflects the name plate (in service) rating; ii. type 2 reflects the normal cyclic rating; and iii. type 3 reflects the N-1 emergency rating.	Refer section 13.3.1 - Net capacity added
For the purposes of the regulatory template, 'customer-initiated & capacity-related augmentation' refer to activities for which incurred costs are attributed to at least one of the following AER expenditure categories:	Refer section 13.3.1 - Assumptions

Requirements (instructions and definitions)	Consistency with requirements
i. New connection - augmentation to subtransmission lines ii. New connection - augmentation to subtransmission substations and subtransmission switching stations iii. New connection - augmentation to zone substations iv. New connection - augmentation to HV CBD feeders v. New connection - augmentation to HV urban feeders vi. New connection - augmentation to HV short rural feeders vii. New connection - augmentation to HV long rural feeders viii. New connection - augmentation to distribution substations, CBD (including downstream LV network) ix. New connection - augmentation to distribution substations, urban (including downstream LV network) x. New connection - augmentation to distribution substations, short rural (including downstream LV network) xi. New connection - augmentation to distribution substations, long rural (including downstream LV network)	
For the purposes of the regulatory template, 'NSP-initiated & capacity-related augmentation' refer to activities for which incurred costs are attributed to at least one of the following AER expenditure categories: Regulatory Information Notice under Division 4 of Part 3 of the National Electricity Law 66 i. NSP-initiated & capacity-related augmentations - subtransmission lines ii. NSP-initiated & capacity-related augmentations - subtransmission stations iii. NSP-initiated & capacity-related augmentations - zone substations iv. NSP-initiated & capacity-related augmentations - HV CBD feeders v. NSP-initiated & capacity-related augmentations - HV urban feeders vi. NSP-initiated & capacity-related augmentations - HV short rural feeders vii. NSP-initiated & capacity-related augmentations - HV long rural feeders viii. NSP-initiated & capacity-related augmentations - distribution substations, CBD (including downstream LV network) ix. NSP-initiated & capacity-related augmentations - distribution substations, urban (including downstream LV network)	Refer section 13.3.1 - Allocation of projects

Requirements (instructions and definitions)	Consistency with requirements
x. NSP-initiated & capacity-related augmentations - distribution substations, short rural (including downstream LV network) xi. NSP-initiated & capacity-related augmentations - distribution substations, long rural (including downstream LV network)	

13.2 Sources

Table 13.2 below sets out the sources from which Energex obtained the required information.

Table 13.2: Information sources

Variable	Source
Capex ($000's, real June 2015)	EPM
Net capacity added - Subtransmission	Substation Investment forecast tool (SIFT), Planning Approval Reports (PARs)
Net capacity added – HV Feeders	EPM
Net capacity added – Distribution substations	EPM

13.3 Methodology

- A summary of the process applied is as follows:
  - Augmentation expenditure was allocated at the project level based on the primary segment group impacted by the project.
  - Augmentation Projects that were trigged by demand growth were included as modelled augmentation.
  - Remaining expenditure was then assigned to the unmodelled augmentation category.
- Energex does not allocate expenditure to the network segments used in the Augex model as part of normal internal reporting practices.

13.3.1 Assumptions

- Energex applied the following assumptions to obtain the required information:

- Actual expenditure and capacity added was allocated to table 2.4.6 at the project level consistent with reporting in Reset RIN Regulatory Template 2.3 (Augex). Information regarding customer initiated augmentation was include in the Reset Regulatory Template 2.5 (Connections) and not reproduced in Reset RIN table 2.4.6.
- Net capacity added is calculated based on the year of project commissioning.
- Net capacity is based on summer ratings.
- New HV feeder capacity is based on the Energex Network Building Blocks manual.

13.3.2 Approach

- Energex applied the following approach to obtain the required information:
  - Allocation of projects to Augex model segment groups
  - Allocation of augmentation expenditure based on project allocation
  - Calculation of net capacity added for each Augex model segment groups
  - Escalation of expenditure to real June 2015

Allocation of projects

- Reset RIN table 2.4.6 was populated based on same lists of projects used to populate Reset RIN table 2.3.4 of template 2.3 (Augex). This ensured consistency in allocation of augmentation expenditure.
- The allocation process required all augmentation projects to be assigned to one of the categories in Reset RIN table 2.4.6. This was completed using 3 lists of augmentation, these project lists were:
  - Projects with forecast expenditure between 2014-15 and 2019-20
  - Projects with expenditure during 2013-14
  - Projects with expenditure between 2009-10 and 2012-13
- The project lists were reviewed sequentially to allocate projects to the Augex model segment groups. As augmentation projects typically span multiple years it was not uncommon for projects to appear in all 3 lists. The project lists were reviewed sequentially to ensure that project allocations remained consistent between the 3 lists.
- Projects with forecast expenditure between 2014-15 and 2019-20 were allocated following review of project documentation including, PARs and planning proposals depending on the current phase of the project.
- The remaining project lists included 7018 projects with expenditure between 2009-10 and 2013-14. Due to the large quantity of projects it was not practical to review each projects to the same degree as projects with forecast expenditure between 2014-15

and 2019-20. These projects were allocated by analysis of high level project information including:

– Financial activity codes
– Budget codes
– NAMP codes

- The financial activity, budget and NAMP codes allocated to Unmodelled augmentations as set out in Table 13.3.

Table 13.3: Unmodelled financial activity and budget codes

Energex codes	description
C2030, C2050	Reliability and power quality projects
C2070	Land acquisition projects
C2075	Easement acquisition projects
C2565 (except NAMPs CA03 and CA04)	Minor company initiated distribution projects
C2080	Demand side management initiatives

- Projects were then allocated based on keyword searches on the project description. Examples of key words are set out in Table 13.4.

Table 13.4: Key word allocation

Key word	description	Allocation
CA03	NAMP code – Uprate pole mounted transformer	modelled
CA04	NAMP code – Uprate pad mounted transformer	modelled
MDI	Maximum demand indicator – projects to uprate distribution substations based on inspections of the maximum demand indicator	modelled
Fault, ftl	Fault level driven project	unmodelled
Prot, ACO, POPS,	These keywords all refer to secondary systems	unmodelled

RTU, VVR, UFLS, 61850, ALFC		
Cap	Project to upgrade capacitor bank for reactive voltage support	unmodelled
SVR, regulator	Static voltage regulator - used to manage voltage limitation on distribution networks.	unmodelled
Tie	Project description to install a tie between two 11kV feeders to improve network security.	modelled
TSCMS	SCADA Comms driven projects	unmodelled

- Remaining projects were then assumed to be driven by maximum demand and allocated as modelled augmentation.
- For projects allocated as modelled augmentation further keyword analysis was used to allocate them each to the specific Augex model segment groups.

Allocation of expenditure

- All projects except distribution substations were able to be allocated to the specific Augex model segment group. Therefore, the annual expenditure was simply the sum of allocated projects in the each year.
- For distribution substations it was not practical to allocate 55% of distribution substation projects to a reliability category based on project description. These projects and associated expenditure, was allocated to urban and short rural distribution substations based on the proportions of known projects, 66% urban and 34% short rural.
- Expenditure associated with projects not driven by demand growth was allocated to the unmodelled augmentation segment group.

Net capacity added

- Total net capacity added was required for the period 2013-14 to 2014-15. This data therefore includes forecast information. Capacity added was provided for the following types set out in the Reset RIN:
  - type 1 reflects the name plate (in service) rating;
  - type 2 reflects the normal cyclic rating; and
  - type 3 reflects the N-1 emergency rating.
- HV feeders and distribution substations only required type 1 (nameplate) ratings to be provided.

- Rating information is constant with other tables in regulatory template 2.4 (Augex Model).
- Net capacity added is not required for unmodelled augmentation.
- The following section will describe the process for each asset class.

Subtransmission lines, subtransmission substations and subtransmission switching stations and zone substations

Energex applied the following approach to determine the net capacity added:

1) A list of projects was obtained from the “Project Dates and Costs” report in SIFT. The list was filtered based on the “PS Commission Date” and “Bus Obj Commission Date” to give projects with a date between 1/7/2013 to 30/6/2015.
2) The relevant PARs were used to confirm the scope of work for each project.
3) For substation projects, the SIFT “Rating calculation by date” function was used. This function allowed the user to calculate the substation ratings based on the active plants at specific point in time. Where there are discrepancies between planning approval and SIFT, the PAR values were used.
4) For subtransmission feeder projects, the pre-project rating of the feeders was obtained from relevant PARs. The post-project ratings were obtained from Erat2.

High voltage feeders and distribution substations

- Due to the large number of HV feeder and distribution substation projects it was not practical to review individual projects and calculate net capacity added. The net capacity added was calculated by applying the “average unit cost of augmentation” from Reset RIN table 2.4.5 (Augex model inputs).
- Net capacity added for 2013-14 to 2014-15 was calculated separately for each year and combined to populate table 2.4.6 or the Reset RIN. 2013-14 capacity was calculated using the historical average unit cost of the relevant AER segment group. 2014-15 was calculated using the forecast average unit cost of the relevant AER segment group.
- The “average unit cost of augmentation” was applied to nominal expenditure prior to being escalated to real June 2015.

Escalation of expenditure

- Reset RIN table 2.4.6 requires all historic expenditure information to be real June 2015. The escalation factors used are set out in Table 13.5. The escalation factors were calculated from the ABS values for CPI based on the eight capital city average.

Table 13.5: Summary of escalation factors

Financial year	Escalation factor to June 2015
2010 FY	1.137
2011 FY	1.105
2012 FY	1.069
2013 FY	1.052
2014 FY	1.029
2015 FY	1

13.4 Estimated Information

- All data provided in Reset RIN table 2.4.6 is estimated due to the allocation process required to provide data consistent with the AER's categories.

13.4.1 Justification for Estimated Information

- Energex does not record expenditure in the same categories as required by the AER, therefore estimates were required to populate Reset RIN table 2.4.6.
- Net capacity added was estimated as it combines forecast and historic data.

13.4.2 Basis for Estimated Information

- Estimates are based on assumptions relating to project drivers and scope. Due to the large number of projects it was not practical to review each project individually to assign it to a segment group, thus the data driven process detailed in the approach was required to generate the data. The data driven approach was validated through peer review of the project lists to improve the reliability of the data.

13.5 Explanatory notes

- Energex does not have any HV feeders classified as long rural.
- Energex has not reported any expenditure or capacity associated with distribution substations – CBD. Energex has only included augmentation expenditure in Reset RIN table 2.4.6. CBD distribution substation expenditure is typically customer initiated and therefore is included in Reset RIN Regulatory Template 2.5 (Connections).

14 BoP 2.5.1 – Connections

The AER requires Energex to provide the following information relating to RIN Table 2.5.1 – Connections Descriptor Metrics:

- Residential Connections
  - Distribution Metrics
  - Augmentation Metrics
- Commercial/Industrial Connections
  - Distribution Metrics
  - Augmentation Metrics
- Subdivision Connections
  - Underground and Overhead Connections
  - Distribution Metrics
  - Augmentation Metrics
  - Cost per Lot
- Embedded Generation Connections
  - Underground and Overhead Connections
  - Distribution Metrics
  - Augmentation Metrics

The AER requires Energex to provide the following information relating to RIN Table 2.5.2 – Connections Cost Metrics (Expenditure and Volume metrics):

- Residential Connections
  - Simple connections expenditure only
  - Complex connections expenditure and volume
- Commercial/Industrial Connections
  - Simple connections expenditure only
  - Complex connections expenditure and volume
- Subdivision Connections
  - Simple connections expenditure and volume
  - Complex connections expenditure and volume
- Embedded Generation Connections
  - Simple connections expenditure and volume
  - Complex connections expenditure and volume

Estimated Information was provided for all figures.

These variables are a part of Regulatory Template 2.5 – Connections.

Please Note: remaining information relating to Regulatory Template 2.5 is covered by the Basis of Preparation in the following section.

14.1 Consistency with Reset RIN Requirements

Table 14.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 14.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must ensure that the data provided for connection services reconciles to internal planning models used in generating Energex's proposed revenue requirements.	Data provided for connection services reconciles to internal planning models.
Energex is not required to distinguish expenditure for connection services between standard or ACS in Regulatory Template 2.5.	No distinction was made between SCS and ACS.
Energex is not required to distinguish expenditure for connection services as either capex or opex in Regulatory Template 2.5.	No distinction was made between opex and capex.
Energex must report expenditure data as a gross amount, by not subtracting customer contributions from expenditure data.	No Cash contributions were included in these tables
Energex must report data for non-contestable, regulated connection services. This includes work performed by third parties on behalf of Energex.	Only data for regulated services was reported.
Energex must not report data in relation to gifted assets, negotiated connection services or connection services which have been classified as contestable by the AER.	No contestable data was reported and no gifted assets were included.
For augmentation metrics, 'km added' refers to the net addition of circuit line length resulting from the augmentation work of complex connections.	Km added takes into account the effect of multiple circuits.
The definitions of *complex connections* in appendix F provide guidance on the types of augmentation works which must be reported as *connection services*, as descriptor metrics for Table 2.5.1 and as cost metrics for Table 2.5.2.	Complex connections were reported in line with the AER's definitions.
Energex must only report augmentation for connections in Regulatory Template 2.5 relating to customer connection requests, as per the definition of connection expenditure in appendix F. Energex must not double count augmentation requirements by twice reporting augmentation data in Regulatory Templates 2.3 and 2.5.	Connection data has not been duplicated across the Regulatory Templates 2.3 and 2.5.
Energex must report the MVA added for distribution substations installed for connection services. Where MVA added must be calculated by Energex as the sum of the nameplate rating of all the distribution	MVA was calculated as the sum of the nameplate

Requirements (instructions and definitions)	Consistency with requirements
substations installed for the relevant year.	ratings.

Estimated Information was provided for all figures.

14.2 Sources

Table 14.2 below sets out the sources from which Energex obtained the required information.

Table 14.2: Information sources

Variable	Source
Table 2.5.1 – Descriptor Metrics	
Residential	
Distribution Substation Metrics	Corvu (FIN027), Ellipse, EPM materials report
Augmentation Metrics	Corvu (FIN027), Ellipse, EPM materials report
Commercial/Industrial	
Distribution Substation Metrics	Corvu (FIN027), Ellipse
Augmentation Metrics	Corvu (FIN027), Ellipse, EPM materials report
Subdivision	
Underground and Overhead Connections	Report Explorer ELL00197 -number of lots commissioned
Distribution Substation Metrics	Corvu (FIN027), Ellipse, EPM materials report
Augmentation Metrics	Corvu (FIN027), Ellipse, EPM materials report
Cost per Lot	Calculated field (Total cost / no. of lots.
Embedded Generation	
Underground and Overhead Connections	PEACE, Network Connection Contracts

Variable	Source
Distribution Substation Metrics	NA
Augmentation Metrics	Corvu (FIN027), Ellipse, EPM materials report
Table 2.5.2 – Cost Metrics	
Residential	
Simple Connection LV	Corvu (FIN027), EPM materials report
Complex Connection LV	Corvu (FIN027), EPM materials report
Complex Connection HV	Corvu (FIN027), EPM materials report
Commercial/Industrial	
Simple Connection LV	Corvu (FIN027), EPM materials report
Complex Connection HV (Customer Connected At LV, Minor HV Works)	Corvu (FIN027), EPM materials report
Complex Connection HV (Customer Connected At LV, Upstream Asset Works)	Corvu (FIN027), EPM materials report
Complex Connection HV (Customer Connected At HV)	Corvu (FIN027), EPM materials report
Complex Connection Sub-Transmission	Corvu (FIN027), EPM materials report
Subdivision	
Complex Connection LV	Corvu (FIN027), EPM materials report
Complex Connection HV (No Upstream Asset Works)	Corvu (FIN027), EPM materials report
Complex Connection HV (With Upstream Asset Works)	Corvu (FIN027), EPM materials report
Embedded Generation	
Simple Connection LV	PEACE, Network Connection Contracts
Complex Connection HV (Small Capacity)	NA
Complex Connection HV (Large Capacity)	NA

14.3 Methodology

All values covered by this Basis of Preparation were developed using the project listings for the relevant financial years. Based on materials booked to projects, project financial activities or project descriptions, these projects were classified into their respective categories required in RIN Tables 2.5.1 and 2.5.2, and the required expenditure and quantities have then been reported.

14.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

General

- HV was defined as anything over 1 kV and LV is defined as anything equal or under 1 kV.

All Residential Variables

- Residential connections were assumed to be equivalent to the Energex financial activity code “C2510 – Domestic and Rural Customer Requested Works” less any projects where the project number begins with ‘S’ (this is considered a subdivision project). Residential variables also include an apportionment of activity code “C2570 – OH Service Connections” for simple LV works based on volume of Residential and Commercial and Industrial connections.

- Any project with a transaction against the Energex expense element “6270 – Capital Contributions Non-cash” that is greater than 90% of the total direct cost of the project was excluded based on the AER’s instructions to exclude gifted assets. Projects with less than 90% gifted were considered to have additional work completed after the asset was gifted and therefore should be included in this Regulatory Template.

- For the volume of connections, it is assumed that each top project represents one connection.

All Commercial/Industrial Variables

- Commercial and Industrial connections were assumed to be equivalent to the Energex financial activity code “C2550 – Commercial and Industrial Customer Requested Work” less any projects where the project number that begins with ‘S’ (this is considered a subdivision project). Commercial/Industrial variables also include an apportionment of activity code “C2570 – OH Service Connections” for simple LV works based on volume of Residential and Commercial and Industrial connections.

- Commercial and Industrial also includes any projects with a C20 or a C35 activity code. Any projects with a customer requested activity, ie C2095 or C2096, are removed as per the reset RIN definition.

- Any project with a transaction against the Energex expense element “6270 – Capital Contributions Non-cash” that is greater than 90% of the total direct cost of the project was excluded based on the AER’s instructions to exclude gifted assets. Projects with less than 90% gifted were considered to have additional work completed after the asset was gifted and therefore should be included in this Regulatory Template.
- For the volume of connections, it is assumed that each top project represents one connection.

All Subdivision Variables

- Subdivision connections were assumed to be any project that has a project number beginning with ‘S’.
- Any project with a transaction against the Energex expense element “6270 – Capital Contributions Non-cash” that is greater than 90% of the total direct cost of the project was excluded based on the AER’s instructions to exclude gifted assets. Projects with less than 90% gifted were considered to have additional work completed after the asset was gifted and therefore should be included in this Regulatory Template.
- For the volume of connections, a query was run from Ellipse to extract the lots commissioned for each project. The percentage of lots for each category was applied to the total figure reported in template 2.5.1.
- Complex connection HV (upstream works) were assumed to be HV connection projects with Energex expenditure greater than $250k. The assumption is based on the definition of Complex subdivision connection high voltage (with upstream asset works). The definition states that the connection may contain:
  - extension or augmentation of HV feeders including major upstream works; and is intended to capture the cost of developing the network to serve new estates and possible upstream shared asset alterations that may be required.
- As “major upstream works” were not defined in the RIN a financial value was used to distinguish projects.

Embedded Generation

- Connection expenditure for large embedded generation projects were excluded as these assets were either gifted, or don’t involve any works. Connection volumes were included.
- Connections expenditure for PV connections is excluded as it is included in Regulatory Template 4.2 (metering). Connection volumes were included.

14.3.2 Approach

Energex applied the following approach to obtain the required information:

- All individual projects undertaken by Energex within each respective year were extracted using the FIN027 report. This report detailed all projects along with the following items:
  - Project description
  - Financial activity code
  - Expenditure
- An extract from EPM of the materials used on each project was joined to the list of projects cost by year. These material transactions were broken down by stock codes which were used to categorise projects into the individual connection classifications. These material transactions were also used to calculate the MVA added and net circuit kilometres added. A large amount of the stock code analysis was leveraged from work undertaken for Regulatory Template 2.2 Repex.
- A number of projects were excluded from the project list to ensure only projects consistent with the connections definition specified by the AER were reported. Table 14.3 provides the details of the project types excluded:

Table 14.3: Projects Excluded from Connections calculations

Exclusions	Reason
Street lighting (defined by activity codes C2560 and C3560 non gifted)	Street lighting projects were not to be included within the connections Regulatory Template.
Projects with gifted assets (defined by projects with any transaction in element 6270)	Where a project costs is 90% or more attributed to the gifted asset element, these projects were excluded.
Incorrectly set up projects (defined by projects under the activity codes C2545 and C2565)	Some projects were incorrectly setup and should not were included in the project list for connections.
Relocation of connection assets	Any projects that were deemed to be relocating connection assets were excluded as they were alterations to the network rather than connections. This included beautification projects.

Table 2.5.1 – Descriptor Metrics

- Once the project list was defined, each project was assigned to be either a distribution substation, augmentation HV or augmentation LV classification by analysing the stock codes charged to each project. The following logic was applied:

- A project was deemed to be a distribution substation project if a transformer was transacted against that project between 2006-07 and 2013-14. Note that the stock codes were analysed in the years prior to and years after the reportable period to ensure that a project was not inadvertently misclassified.
- A project was deemed to be a HV or LV project based on the highest proportion of cable (based on expenditure) booked to the project. Cable figures were analysed from 2006-07 to 2013-14 to ensure a project was not inadvertently misclassified. If a project had a higher dollar figure of HV cable across these years then it would be classified as a HV project and vice versa. If there was no material to indicate voltage, then the project was assumed to be HV.

Residential

- Distribution Substation Installed Metrics
  - Residential connections with distribution substations were determined to be those projects with an activity code "C2510 – Domestic and Rural Customer Requested Works" where the project code does not start with 'S' and had distribution transformers transacted against the project. The MVA added was calculated by analysing the stock code transactions against each applicable project. This involved assigning an MVA added for each stock code transaction based on the stock item description and quantity and then each figure was summated to give the total.
  - The number of distribution substations was calculated as the frequency of projects that were classified as distribution substation.
  - The total spend figure was calculated as the cost incurred for each project for each respective year.
- Augmentation HV Metrics
  - Residential connections with HV augmentation were determined to be those projects with an activity code "C2510 – Domestic and Rural Customer Requested Works" where the project code does not start with 'S' and had a majority of HV cable transacted against the project. The circuit length added was calculated by analysing the stock code transactions against each applicable project. This involved assigning a circuit length added for each stock code transaction based on the item description and length of cable, adjusting for cables with multiple circuits and then each figure was summated to give the total.
  - The total spend figure was calculated as the total project cost for each respective year.
- Augmentation LV Metrics
  - Residential connections with LV augmentation were determined to be those projects with an activity code "C2510 – Domestic and Rural Customer Requested Works" where the project code does not start with 'S' and had a majority of LV cable transacted against the project. Added to this was also an

apportionment of projects with the activity code “C2570 – Service Connections”. The projects under C2570 were allocated between Residential and Commercial/Industrial customers based on the proportional amount of connection volumes for each respective year.

  – The circuit length added was calculated by analysing the stock code transactions against each applicable project. This involved assigning a circuit length added for each stock code transaction based on the item description and length of cable, adjusting for cables with multiple circuits and then each figure was summated to give the total.

  – The total spend figure was calculated as the total project cost for each respective year for projects under C2510 as well as the apportionment of project cost to the residential classification from C2570.

Commercial/Industrial

- Distribution Substation Installed Metrics
  – Commercial/Industrial connections with distribution substations were determined to be those projects with an activity code “C2550 – Commercial and Industrial Customer Requested Works” where the project code does not start with ‘S’, or a funding type of C20 or C35 that had distribution substations transacted against the project. The MVA added was calculated by analysing the stock code transactions against each applicable project. This involved assigning an MVA added for each stock code transaction based on the item description and quantity and then each figure was summated to give the total MVA.
  – The number of distribution substations was calculated as the frequency of projects that were classified as distribution substation.
  – The total spend figure was calculated as the total project cost for each respective year.
- Augmentation HV Metrics
  – Commercial/Industrial connections with HV augmentation were determined to be those projects with an activity “C2550 – Commercial and Industrial Customer Requested Works” where the project code does not start with ‘S’ or a funding type of C20 or C35 that had a majority of HV cable transacted against the project. The circuit length added was calculated by analysing the stock code transactions against each applicable project. This involved assigning a circuit length added for each stock code transaction based on the item description and length of cable, adjusting for cables with multiple circuits and then each figure was summated to give the total.
  – The total spend figure was calculated as the total project cost for each respective year.
- Augmentation LV Metrics
  – Commercial/Industrial connections with LV augmentation were determined to be those projects with an activity code “C2550 – Commercial and Industrial

Customer Requested Works" where the project code does not start with 'S' or a funding type of C20 that had a majority of LV cable transacted against the project. Added to this was also an apportionment of projects with the activity code "C2570 – Service Connections". The projects under C2570 were allocated between Residential and Commercial/Industrial customers based on the proportional amount of connection volumes for each respective year.

  – The circuit length added was calculated by analysing the stock code transactions against each applicable project. This involved assigning a circuit length added for each stock code transaction based on the item description and length of cable, adjusting for cables with multiple circuits and then each figure was summated to give the total.
  – The total spend figure was calculated as the total project cost for each respective year for projects under C2550 as well as the apportionment of project cost to the residential classification from C2570.

Subdivision

- Underground and Overhead Connections
  – To obtain the split between overhead and underground lots gifted to Energex in a financial year, Energex reviewed the lots contracted for the financial periods required. This allowed Energex to identify the number of lots contracted that were UG and the number OH. It applied this ratio to the number of lots gifted to Energex in the financial period.
- Distribution Substation Installed Metrics
  – Subdivision connections with distribution substations were determined to be those projects with a project code beginning with 'S' that had distribution substations transacted against the project. The MVA added was calculated by analysing the stock code transactions against each applicable project. This involved assigning an MVA added for each stock code transaction based on the item description and quantity and then each figure was summated to give the total MVA.
  – The number of distribution substations was calculated as the frequency of projects that were classified as distribution substation.
  – The total spend figure was calculated as the total project cost for each respective year.
- Augmentation HV Metrics
  – Subdivision connections with HV Augmentation were determined to be those projects with a project code beginning with 'S' that had the majority of HV cable transacted against the project. The circuit length added was calculated by analysing the stock code transactions against each applicable project. This involved assigning a circuit length added for each stock code transaction based on the item description and length of cable, adjusting for cables with multiple circuits and then each figure was summated to give the total.

- – The total spend figure was calculated as the total project cost for each respective year.

- Augmentation LV Metrics
  - – Subdivision connections with LV Augmentation were determined to be those projects with a project code beginning with ‘S’. The MVA added was calculated by analysing the stock code transactions against each applicable project. This involved assigning an MVA added for each stock code transaction based on the item description and quantity and then each figure was summated to give the total MVA.
  - – The total spend figure was calculated as the total project cost for each respective year.

- Cost per Lot
  - – To obtain the cost per lot, Energex used the total cost reported in RIN Table 2.5.1 for subdivisions divided by the number connections reported in overhead and underground connections for Subdivisions for the year.

Embedded Generation

- Underground and Overhead Connections
  - – Small solar PV system connections (<30 kW) were extracted from the PEACE customer Information System through report FRC213.
  - – The split of connections into the underground and overhead categories was done using the connection type found in the FRC213 report. Where connections did not have a connection type the residual connections were allocated to underground and overhead based on the proportions of known connection types.
  - – The number of large connections (>30 kW) were determined by reviewing network connection contracts.
  - – The total number of connections reported was the sum of connections >30kW and <30kW.
  - – No augmentation costs or volumes were allocated to embedded generation. The main costs of solar PV relate to metering works to enable to connection. Metering costs relating to solar PV were included in Regulatory Template 4.2.

Table 2.5.2 – Cost Metrics

Once the project list was defined the variables required with Table 2.5.2 were calculated as follows:

Residential

- Simple Connection LV (expenditure only)
  - – All expenditure for projects under the activity code “C2570 – Service Connections” was extracted. The total expenditure figure was then allocated

between Residential and Commercial/Industrial customers based on the proportional amount of connection volumes for each respective year.

- Complex Connection LV
  - Residential complex connections were defined as being those projects under the activity code “C2510 – Domestic and Rural Customer Requested Works” where the project code does not start with ‘S’. The split between LV and HV was made using an analysis of stock codes transacted against each project. LV was defined as any project that did not include a transformer and had cable installed that was less than or equal to 1kV. Where a project included both LV and HV cables the project was allocated based on the cable type with the highest expense value.
  - The expense values were calculated as the total project expenses for each respective year. The volumes of connections were calculated by using the frequency of projects for each year.
- Complex Connection HV
  - Complex connection HV was defined as those projects under activity code “C2510 – Domestic and Rural Customer Requested Works” where the project code does not start with ‘S’ and that included a transformer, high voltage cable (>1kV) or both. For projects in activity C2510 where there were no materials to indicate voltage, these projects were assumed to be HV.
  - The expense values were calculated as the total project expenses for each respective year. The volumes of connections were calculated by using the frequency of projects for each year.

Commercial/Industrial

- Simple Connection LV (expenditure only)
  - All expenditure for projects under the activity code “C2570 – Service Connections” was extracted. The total expenditure figure was then allocated between Residential and Commercial/Industrial customers based on the proportional amount of connection volumes for each respective year. Added to this was expenditure for selected projects under the activity code “C2550 – Commercial and Industrial Customer Requested Works” where the project code does not start with ‘S’. These projects were identified as being LV projects by analysis of the project description.
- Complex Connection HV (Customer Connected At LV, Minor HV Works)
  - This classification was determined to be the remainder of projects under the activity code “C2550 – Commercial and Industrial Customer Requested Works” where the project code d not start with ‘S’.
  - The expense values were calculated as the total project expenses for each respective year. The volumes of connections were calculated by using the frequency of projects for each year.

- Complex Connection HV (Customer Connected At LV, Upstream Asset Works)
  - This classification was determined to be the remainder of projects under the C20 or C35 funding type.
  - The expense values were calculated as the total project expenses for each respective year. The volumes of connections were calculated by using the frequency of projects for each year.
- Complex Connection HV (Customer Connected At HV)
  - This classification was determined to be projects under the C20 funding type that were identified as HV projects. The projects were identified as being HV by analysis of the stock codes under each project.
  - The expense values were calculated as the total project expenses for each respective year. The volumes of connections were calculated by using the frequency of projects for each year.
- Complex Connection Sub-Transmission
  - This classification was determined to be projects under the C20 funding type that were identified as sub-transmission projects. The projects were identified as being sub-transmission by analysis of the project description.
  - The expense values were calculated as the total project expenses for each respective year. The volumes of connections were calculated by using the frequency of projects for each year.

Subdivision

- Complex Connection LV
  - This classification was determined to be projects with a project number starting with 'S'. The split between LV and HV was made using an analysis of stock codes transacted against each project. LV was defined as any project that did not include a transformer and had cable installed that was less than or equal to 1kV. Where a project included both LV and HV cables the project was allocated based on the cable type with the highest expense value.
- Complex Connection HV (No Upstream Works)
  - This classification was determined to be projects with a project number starting with 'S' and that included a transformer, high voltage cable (>1kV) or both. For projects that start with an 'S' where there were no materials to indicate voltage, these projects were assumed to be HV.
- Complex Connection HV (Upstream Works)
  - This classification was determined to be projects with a project number starting with 'S' where the expense was greater than $250,000.

Embedded Generation

- Simple Connection LV

  - No expenditure data was supplied in this category as per assumptions stated above.
  - Volume data was based on Small solar PV system connections (<30 kW) plus volumes extracted from network connection contracts.

- Complex Connection HV (Small Capacity)
  - No expenditure data was supplied in this category, as per assumptions.
  - Volume data was based on network connection contracts.

- Complex Connection HV (Large Capacity)
  - No expenditure data was supplied in this category, as per assumptions.
  - Volume data was based on network connection contracts.

14.4 Estimated Information

- The simple LV connection expenditure from activity C2570 which is apportioned over Residential and Commercial/Industrial is considered to be an estimate.

- All data is estimated as the apportionment to each category is based on materials booked to the project, project description or financial activity code.

14.4.1 Justification for Estimated Information

- Data is not captured in the categories required in RIN Tables 2.5.1 and 2.5.2, therefore costs were required to be apportioned.

14.4.2 Basis for Estimated Information

- Each cost and quantity was manually categorised using multiple descriptors within the data. For full details please refer to the approach section above.

14.5 Explanatory notes

- The connection counts were based upon the count of projects that were determined to fall in the particular categories required in Regulatory Template 2.5. Where a project was done over multiple years it may be counted more than once, however the effect of this is immaterial. All MVA added and circuit kilometres added metrics were based on the stock codes charged to the project in each particular year and will therefore not be double counted.

- LV connection expenditure is largely based on activity C2570. This activity includes approximately $93 million in metering expenditure. This is detailed in Regulatory Template 4.2. Expenditure associated with metering was removed from activity C2570 prior to allocation in Regulatory Template 2.5.

- A general reduction in MVA installed and costs associated with it is due to the reduction in load forecasts, and therefore reduced requirements for customer driven demand spend. The variability of the commercial MVA installed is driven by the types of projects commissioned for a particular financial year. This can include allowance for future growth.

- Historical data within the Reset RIN differs from information submitted in the Category Analysis (CA) RIN due to the updated definition of connection expenditure in the Reset RIN which makes the exclusion of relocation of assets explicit. Per the Reset RINs updated definition, relocation of assets expenditure was excluded from data presented including prior years.

- It should be noted that, whilst extracting and analysing data and applying an exclusion for metering costs for the Reset RIN for the 2013/14 year an error was identified in relation to information previously reported for the CA RIN. This error relates to the incorrect exclusion of some costs reported for connections in the CA RIN. This error has been corrected but has resulted in inconsistencies between data reported in the CA RIN and that reported in the Reset RIN.

15 BoP 2.5.2 – Connections – UG, OH and Simple Connections

The AER requires Energex to provide the following information relating to Connection Descriptor Metrics:

- **Underground Connections (Residential, Commercial/Industrial & Embedded Generation)**
- **Overhead Connections (Residential, Commercial/Industrial & Embedded Generation)**
- **Mean days to connect a residential customer with LV single phase connection**
- **Volume of GSL breaches for residential customers**
- **Volume of customer complaints relating to connection services**

The AER requires Energex to provide the following information relating to Cost Metrics by Connection Classification:

- **Simple Connection LV (Residential and Embedded Generation)**

Actual information was provided for the volume of connections, complaints and GSLs whilst estimated information was provided for the volume of underground and overhead connections.

These variables are a part of worksheet 2.5– Connections

15.1 Consistency with Reset RIN Requirements

Table 15.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 15.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must provide information within the relevant reportable year for the following; Volume of connections for residential, commercial and industrial customers	Demonstrated in section 15.3.
GSL payments made to residential customers	Demonstrated in section 15.3.
Volume of complaints relating to connection services	Demonstrated in section 15.3.
Connection means a physical link between a distribution system and a retail customers premises to allow the flow of electricity.	Demonstrated in section 15.3

Simple connection low voltage is defined as a single/multiphase customer service connection.	Demonstrated in section 15.3
Complaint is defined as a written or verbal expression of dissatisfaction about an action, or failure to act, or in respect of a product or service offered or provided by an electricity network distributor.	Demonstrated in section 15.3

Actual information was provided for

- Residential Simple Connection LV
- Commercial/Industrial Simple Connection LV
- Embedded Generation Simple Connection LV
- Volume Of GSL Breaches For Residential Customers
- Volume Of Customer Complaints Relating To Connection Services
- Mean Days To Connect Residential Customer With LV Single Phase Connection

Estimated information was provided for

- Residential Underground Connections
- Residential Overhead Connections.
- Commercial/Industrial Underground Connections
- Commercial/Industrial Overhead Connections.
- Embedded Generation Underground Connections
- Embedded Generation Overhead Connections.

15.2 Sources

Table 15.2 below sets out the sources from which Energex obtained the required information.

Table 15.2: Information sources

Variable	Source
Connections & Embedded Generation Volumes	PEACE (FRC213)
Complaints	Cherwell & FROG

GSL Payments	Cherwell & GUS

15.3 Methodology

- Data provided in table 2.5.2 and 2.5.1 is derived from the business objects report FRC213 which extracts data from PEACE CIS system. FRC213 is automatically run each day to extract details of any service order that reached a status of “service order response sent” (for Retailer initiated work) on the previous business day. The FRC213 report also identifies the market outcome status for each service order. This market outcome status identifies whether the service order was completed, attempted but unable to be completed, or cancelled.

- Due to the above parameters, the FRC213 report details service order jobs based on the date the service order response was sent to the requesting retailer and not the date the job was completed in the field. As such, at times there may be a variance between the date the job is completed in the field and the date the job appears in FRC213.

- Complaint data is derived from a feedback report which extracts information from the FROG system (for volumes in 2008-09 and 2009-10) and the Cherwell system (for volume in 2010-11 onwards) and encompasses all complaints received to Energex (via phone, letter or email). The report details the date the complaint was received and is categorised by the Customer Relations team using the systems feedback structure.

- Guaranteed Service Level (GSL) data is derived from a report which extracts information from the Guaranteed Service Level Utility System (GUS) for volumes in 2008-09 and 2009-10, and the Cherwell system for volumes from 2010-11 onwards. The report details the type of GSL, the amount paid to a customer and the relevant date the payment was made.

15.3.1 Assumptions

- Data provided includes New Connections, Connection Alterations and Basic Embedded Generation Connection as defined by the National Electricity Rules.

- Connections have been collated based on customer initiated work requests within the reportable period.

- For the volume of connections, it is assumed that each top project represents one connection which was determined as per basis of preparation in table 2.5.1. all remaining connection not associated with a project were determined to be simple.

- New connection service orders include both permanent and temporary connections thereby making it possible for more than one new connection service to occur for the same premises (NMI) within the reportable period.

- Mean days to connect residential customer with LV single phase connection has been determined by calculating the average days between the earliest work start date and the actual completion date (field worker completes work in field) for a connection associated with the same NMI. The earliest work start date is defined as the latest date of either;
  - B2B Received Date + 1
  - B2B Obligation Start Date
  - Form 2 Received Date + 1
  - Form 2 Ready for Test Date.
  - Appointment Date
- Mean days to connect may be artificially inflated where obligation timeframes have been renegotiated with a customer in line with the Electricity Industry Code. In these circumstances the earliest work start date is not updated to reflect new timeframes thereby inflating the average days to connect despite obligation timeframes having been changed and connections completed within required timeframes.
- GSLs are payable to small NMI class customers only therefore data provided has been based on the assumption that a small NMI classification is that of a residential customer.

15.3.2 Approach

Energex applied the following approach to obtain the required information:

Connections

1) Collation of monthly reports for financial year
2) Total volumes of connections to the network are established by summing the total volume of connection service orders (from the FRC213 reports) where the market outcome status was “complete” for the financial year.
3) Calculation of underground and overhead connections estimates were applied where data was unavailable

Complaints

1) Collation of monthly reports for financial year
2) Exclusion of complaints not categorised as the following:
   a. New connection
   b. Existing connection
3) Total volumes of complaints relating to connections are established by summing the total volume of the above complaint categories for the financial year.

GSLs

1) Collation of monthly reports for financial year

2) Exclusions of GSLs not categorised as the following

   a. New Connection

3) Total volumes of GSLs are established by summing the total volume of the New Connection GSLs paid for each financial year.

15.4 Estimated Information

Energex applied the following estimates to obtain the required information of overhead and underground connection types:

- As connection data is based upon business to business (B2B) information, the connection type taken from FRC213 is used to determine the total number of underground and overhead connections. Where a connection type was not able to be attained these reflect instances where a retailer has not supplied this information within the B2B.

15.4.1 Justification for Estimated Information

- When submission of a B2B from a Retailer does not indicate the connection type, the extracts obtained from PEACE CIS will not return any value. It was necessary to estimate required information as it is not possible to obtain the level of detail elsewhere.

15.4.2 Basis for Estimated Information

- Where there was insufficient data Energex has adopted an apportionment approach. That is, of the total connections where a connection type was supplied, the percentage of these connection types within the relevant year was applied to the instances where insufficient connection type information was available. This approach has been used as it represents a fair and valid calculation for those occasions where a connection type cannot be identified.

15.5 Explanatory notes

- Energex's service order timeframe performance during 2011/12 year was impacted by a substantial increase in volumes of solar photovoltaic (PV) service order requests. This was driven by changes to the Federal Government's Renewable Energy Certificate (RECs) scheme which, from 30 June 2011, reduced the number of RECs available for solar PVs. This was the main contributor the increase in Average Days to connect customer during the 2010/11 and 2011/12 periods.

- New Connection GSLs paid in during the 2008/09 period were impacted by the PEACE system upgrade which took effect in July 2008 in line with the commencement of Full Retail Contestability (FRC). These service orders failed to transition to the PEACE system in order to be completed within the obligated timeframes.

- Embedded Generation volumes experienced considerable decline in 2013/14 year when compared to prior years reported. This is a reflection of changes in Government rebate schemes and the subsequent decline in consumer appetite.
- Historical data for the number of connections reported in the Reset RIN differs from that reported in the Category Analysis (CA) RIN due to a change in the methodology applied. Instead of adding the number of connection projects to the connection numbers (as was the case when collating data for the CA RIN) the Reset RIN data assumes that volumes should reconcile to the connection numbers and therefore each top project represents one connection which was determined as per basis of preparation in table 2.5.1. All remaining connections not associated with a project were determined to be simple.

16 BoP 2.6.1 – Non-Network – IT & Communications

The AER requires Energex to provide the following information relating to Non-Network Expenditure and annual descriptor metrics for years 2008/09 to 2013/14:

- **Client Devices Opex and Capex**
- **Recurrent Opex and Capex**
- **Non-Recurrent Opex and Capex**
- **Employee Numbers, users numbers and number of devices**

Actual Information was provided for all variables.

This document provides information regarding Energex total expenditure on IT and Communications (i.e. includes SPARQ costs which are charged to Energex as operating costs)

These variables are a part of Regulatory Template 2.6 – Non-Network Expenditure.

16.1 Consistency with Reset RIN Requirements

Table 16.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER

Table 16.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
If expenditure is directly attributable to an expenditure category in this Regulatory Template 2.6 it is a Direct Cost for the purposes of this Regulatory Template. Report all capex and/or opex Direct Costs as required, irrespective of whether any Direct Costs are also classified as Corporate Overheads, Network Overheads or other capex or opex categories. To the extent this results in multiple reporting of expenditures, identify this in accordance with instructions at paragraph 2.3 above.	Energex has reported all figures inclusive of Direct costs and on-costs but excluding overheads as per the Energex CAM approved by the AER.
The AER defines Non-network IT & Communication - user numbers as Active IT system log in accounts used for standard control services work scaled for standard control services use (i.e. an account used 50% of the time for standard control services work equals 0.5 active IT log in accounts)	Information reported in table 2.6.2 is in line with this definition.
The AER defines Non-network It & Communications – device numbers as the number of client devices used to provide standard control services scaled for standard control services use (i.e. a device used 50% of the time	Information reported in table 2.6.2 is in line with this definition.

Requirements (instructions and definitions)	Consistency with requirements
for standard control services work equals 0.5 devices). Client Devices are hardware devices that accesses services made available by a server and may include desktop computers, laptops, tablets and thin client interfaces and handheld end user computing devices including smart phones.	
The AER defines Non-network IT & Communications - Non Recurrent Expenditure as IT & Communications - Non Recurrent is all IT & Communications Expenditure that is Non-recurrent Expenditure excluding any expenditure reported under IT & Communications Expenditure - Client Devices Expenditure.	Information reported in table 2.6.1 is in line with this definition.
Non-network IT & Communications Expenditure as Is all non-network expenditure directly attributable to IT and communications assets including replacement, installation, operation, maintenance, licensing, and leasing costs but excluding all costs associated with SCADA and Network Control Expenditure that exist beyond gateway devices (routers, bridges etc.) at corporate offices. IT & Communications Expenditure includes: • costs associated with SCADA and Network Control that exist at the Corporate office side of gateway devices (routers, bridges etc.). For example, this would include cost associated with SCADA master systems/control room and directly related equipment • IT & Communications Expenditure related to management, dispatching and coordination, etc. of network work crews (e.g. phones, radios etc.). • any common costs shared between the SCADA and Network Control Expenditure and IT & Communications Expenditure categories with no dominant driver related to either of these expenditure categories. For example, a dedicated communications link used for both corporate office communications and network data communications with no dominant driver for incurring the expenditure attributable to either expenditure category should be reported as IT & Communications Expenditure. • expenditure related to network metering recording and storage at non network sites (i.e. corporate offices/sites) • Sub categories of Non-network IT& Communications	Information reported in table 2.6.1 is in line with this definition.

Requirements (instructions and definitions)	Consistency with requirements
Expenditure are: • Client Devices Expenditure • Recurrent Expenditure (excluding any client devices expenditure) Non-Recurrent Expenditure (excluding any client devices expenditure).	
The AER defines Non-network IT & Communications Expenditure - Client Devices Expenditure as expenditure related to a hardware device that accesses services made available by a server. Client Devices Expenditure includes hardware involved in providing desktop computers, laptops, tablets and thin client interfaces and handheld end user computing devices including smart phones.	Information reported in table 2.6.1 is in line with this definition.
The AER defines Non-network IT & Communications Expenditure – Descriptor Metric – employee numbers as the average number of employees engaged in standard control services work over the year scaled for time spent on standard control services work (i.e. an employee spending 50% of their time on standard control services work equating to 0.5ASLs for the purposes of the labour metrics would be 0.5 employees). This metric does not include labour engaged under labour hire agreements.	Information reported in table 2.6.2 is in line with this definition.
The AER defines Non-network IT & Communications Expenditure - Recurrent Expenditure as all IT & Communications Expenditure that is Recurrent Expenditure excluding any expenditure reported as IT & Communications Expenditure - Client Devices Expenditure.	Information reported in table 2.6.1 is in line with this definition.

Actual Information was provided for all variables.

16.2 Sources

The following sources were used by SPARQ Solutions to extract information for Energex:

- The financial data provided in Table 2.6.1 was extracted from monthly billing invoices provided to Energex by SPARQ Solutions in relation to ICT services rendered as recorded in the SPARQ Solutions finance system.
- Non-financial data provided in Table 2.6.2 was sourced as follows:
  – Employee numbers – Energex Annual Stakeholder Reports contained on the Energex website.

- User numbers – from software licencing compliance reports for the period 2008/09 & 2009/10 and for the period 2010/11 to 2013/14 from Microsoft Active Directory reports (these were not prepared prior to 2010/11 FY)
- Number of devices – the data reported was sourced from reports used for demonstrating compliance to Microsoft for the licensing obligations associated with the Microsoft applications used by these devices. These counts were determined using System Centre Configuration Manager (SCCM) and Microsoft Active Directory reports.
- SCCM is a Microsoft product used for systems management which has the ability to auto discover devices on the network and determine what software etc. is running on them.
- Active Directory is a Directory Service product produced by Microsoft and used by SPARQ Solutions to manage network user accounts and computer objects. All employees were given a user account within Active Directory. Underpinning the directory service is a database which contains unique identifiers for each object as well as various attributes associate with those objects. Reports were run against this database to determine the number of employees, active computers etc.

- The following sources were used in the generation of the ICT figures:
  - EPM – FIN032 Divisional Profit and Loss
  - Ellipse – "Accounting Entry Report – incl Proj & WO Desc (ECA90W)"
  - Regulatory Accounts
  - SPARQ Solutions information as per RIN – Financial System Ellipse

Table 16.2 below sets out the sources from which Energex obtained the required information.

Table 16.2: Information sources

Variable	Source
Client Device Expenditure – OPEX ($000's)	SPARQ Solutions information based on invoices issued to Energex
Client Device Expenditure – CAPEX ($000's)	Accounting Entry Report per Ellipse
Recurrent Expenditure – OPEX ($000s)	Profit and Loss for SPARQ Solutions division from EPM for Cost of Sales, Telecommunications, Asset Usage Fee, Finance Fee & SLA
Recurrent Expenditure – CAPEX ($000s)	Capex expenditure per Regulatory accounts less Client Devices per Accounting Entry Report
Non-Recurrent Expenditure – OPEX	Profit and Loss MOPEX RC 2310, account 4940 for 08/09

Variable	Source
($000s)	Profit and Loss MOPEX RC 1025, account 4940 for 09/10 to 12/13 Profit and Loss MOPEX RC 1020, account 4940 for 13/14
Non-Recurrent Expenditure – CAPEX ($000s)	Not applicable
Employee numbers	Sourced from annual shareholders reports of Energex
User numbers	Active IT system log in account used in the year
Number of devices	Client devices used as provided IT services

16.3 Methodology

- The ICT figures for the RESET RIN were developed by Energex with the assistance of SPARQ Solutions, the Energex ICT provider. SPARQ Solutions was created as its own entity to be the joint ICT provider for both Energex and Ergon in 2008/09. The employees for SPARQ Solutions came from the original ICT functions within Energex and Ergon.

- The cost information provided in RIN Table 2.6.1 is as sourced from the SPARQ Solutions financial system and is stated "as billed" to Energex. The treatment of these costs as operating or capital expenditure is determined by Energex using its Cost Allocation Model.

- Costs billed by SPARQ Solutions were not allocated to specific Energex business operations as this is dealt with internally by Energex using the Cost Allocation Model. In providing the sub-category financial data, SPARQ Solutions applied the definitions provided by the AER on the following basis:
  - Non recurrent expenditure comprises costs incurred for Energex projects which may be reported as either operating or capital costs in Energex (this allocation was determined by Energex).
  - Client device expenditure reflects costs of supporting the operation and use of the Energex end user device fleet, including service desk support.
  - Recurrent expenditure comprises all other IT & communications costs incurred with SPARQ Solutions by Energex. Following recent clarification of changes in treatment provided by Energex of Network ICT costs, this sub-category includes the cost of supporting the Energex Network Control and Distribution Management Systems.

- ICT data was reconciled by Energex between the two organisations and certain items pertaining to the employee transfers in 2008/09 were required to be adjusted.

16.3.1 Approach

Energex applied the following approach to obtain the required information:

OPEX

- SPARQ Solutions provided financial data detailing the charges from SPARQ Solutions to Energex for the financial years as per the breakdown required in the RESET RIN. SPARQ Solutions reconciled these charges to invoices and their audited financial statements for SPARQ Solutions from EPM by financial year. Prior to SPARQ Solutions being created, the ICT services were managed under the Energex CIO. As such, the responsibility centres in the years 2008/09 and 2009/10 were part of the original area of the “Chief Information Officer”. The number of responsibility centres for 2010/11 onwards was then rationalised down to a virtual unit called “SPARQ” with 3 responsibility centres. The following responsibility centres were used for the EPM reports:
  - 08/09 – 2310, 2311, 2312, 2313, 2315, 2320, 2330, 2335, 2340, 2350, 2360
  - 09/10 – 2310, 2311, 2312, 2313, 2315, 2320, 2330, 2335, 2340, 2350, 2360, 1020, 1025, 1030, 1390
  - 10/11 to 13/14 – SPARQ division within EPM
- Energex then reconciled the SPARQ Solutions data to profit and loss reports from EPM. The SPARQ Solutions data was reconciled to the following accounts:
  - 4940 - Sparq Contractor
  - 4945 - Contr- Sparq Asset Usage Fee
- Any variances were investigated and identified to ensure the SPARQ Solutions information matched the Energex financial records.
- Client Devices Opex – SPARQ Solutions has populated the Opex component on behalf of Energex based on their invoices issued to Energex for client devices.
- Recurrent Opex – Calculated as the total of the Cost of Sales, Telecommunications Costs, Asset Usage Fee, Finance Fee and SLA from Energex EPM reports. The "Cost of Sales" expenditure relates to the purchase for small ICT equipment. The telecommunications costs relates to reclass of telecommunication costs for Metering Dynamics and some small item CAPEX purchases sent through the SLA. These figures were reconciled to the SPARQ Solutions RIN information.
- Inventory is capitalised in Energex accounts and as such it was excluded from the recurrent expenditure charge.
- As the provision for annual leave and long service leave was held in Energex, when leave was taken by SPARQ Solutions employees who original employed by Energex, the expenses were invoiced to Energex via a SPARQ Solutions invoice and allocated against the balance sheet provision. Annual Leave in 08/09 and 09/10 which is treated as operating costs in SPARQ Solutions was excluded as the costs went directly to the Balance Sheet for Energex to offset the existing provision.

- Non-recurrent Opex, as per the definition, is deemed to be the Energex MOPEX payments. MOPEX costs were Energex project related costs which were expensed in the Energex Profit and Loss. These costs relate to project scoping and development costs which in accordance with Energex Finance Policy cannot be capitalised. MOPEX costs were costed to one separate Responsibility centre (for the period 08/09 RC 2310, for the period 09/10 to 12/13 RC 1025 and for the period 13/14 RC 1020) and were sourced from the relevant EPM report for that RC.

CAPEX

- Client devices Capex – Client devices capex was identified from the Accounting Entry Report for each year, as extracted from Ellipse.
- Recurrent Capex – Recurrent CAPEX is calculated as the difference between total Energex ICT Capex as recorded in the Regulatory accounts less the client devices calculated above.
- Non-recurrent Capex – in accordance with the RIN definitions there is no non-recurrent ICT Capex for Energex

Descriptor Metrics

- Employee Numbers – The employee numbers were extracted directly from the Energex annual shareholders reports.
- User Numbers – The number of users was extracted as the number of active IT system log-in accounts used during each year.
- Number of Devices – The number of devices was extracted as the number of client devices used as provided by SPARQ Solutions.

16.4 Estimated Information

Energex has not used estimated data in preparation of this RIN.

16.5 Explanatory notes

- SPARQ Solutions does not prepare Regulatory Accounting Statements as it is not a regulated entity in its own right. However the financial data provided in RIN Table 2.6.1 is sourced from SPARQ Solutions financial systems and is verifiable by reference to its audited Statutory Accounts. In addition, the financial data used to determine costs specific to Energex (i.e. monthly billing invoices) was subject to periodic Internal Audit reviews in the 2008/09 to 2012/13 period to demonstrate the integrity of cost allocation and billing processes to its clients.

The following items caused significant movement between financial years:

- Recurrent expenditure CAPEX ($000s)

  - 2009/10 - Newstead Fitout $4,535,176 (work order SD3106) and MS Enterprise Agreement $3,947,050
  - 2010/11 - Newstead Fitout $3,244,640 (work order SD3106)

- Client Devices CAPEX ($000s)
  - 2011/12 - ToughBooks $3,308,719 (work order SD5059)

- Non Recurrent Expenditure OPEX ($000s) - Relates to MOPEX expenditure
  - 2011/12 - Blueprinting $2,031,526 (work order SD5025) and Ellipse 8 $3,557,536 (work order SD5003)

16.6 Accounting policies

The Accounting Policies that have been adopted by Energex during these Regulatory Years covered by the Notice have not materially changed in nature.

17 BoP 2.6.2 – Non-Network – Fleet, Tools and Equipment

The AER requires Energex to provide the following variables relating to RIN Table 2.6.1 Non-Network Expenditure:

- **Motor Vehicles – Opex and Capex**
- **Other Non-Network Expenditure Fleet Tools & Equipment – Opex and Capex**

The AER requires Energex to provide the following variables relating to RIN Table 2.6.3 Non-Network Expenditure:

- **Motor Vehicles Descriptor Metrics**

Actual Information was provided for all figures.

These variables are a part of Regulatory Template 2.6 Non-Network.

17.1 Consistency with Reset RIN Requirements

Table 17.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 17.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
If expenditure is directly attributable to an expenditure category in this regulatory template 2.6 it is a Direct Cost for the purposes of this regulatory template 2.6. Report all capex and/or opex Direct Costs as required, irrespective of whether any Direct Costs are also classified as Corporate Overheads, Network Overheads or other capex or opex categories. To the extent this results in multiple reporting of expenditures, identify this in accordance with instructions at paragraph 2.3 above.	All Direct Costs have been reported as required. Any instances of multiple reporting of expenditure have been identified in accordance with paragraph 2.3 and recorded as a balancing item.
In relation to the Non-network Other expenditure category, if Energex has incurred $1 million or more (nominal) in capital expenditure over the last five regulatory years for a given type or class of assets (e.g. mobile cranes), Energex must insert a row in the regulatory template and report that item separately.	Energex has nominated, and reported separately, expenditure for the following Service Sub-categories and Asset Categories: • Other – Other Fleet: Mobile Generators – Other Fleet: Trailers – Other: Tools & Equipment – Other

Requirements (instructions and definitions)	Consistency with requirements
The AER defines a Car as Motor Vehicles other than those that comply with the definition of Light commercial vehicle, Heavy commercial vehicle, Elevated work platform (LCV) or Elevated work platform (HCV).	This definition has been applied.
The AER defines Light commercial vehicles (LCVs) as Motor Vehicles that are registered for use on public roads excluding elevated work platforms that: • are rigid trucks or load carrying vans or utilities having a gross vehicle mass greater than 1.5 tonnes but not exceeding 4.5 tonnes; • or have cab-chassis construction, and a gross vehicle mass greater than 1.5 tonnes but not exceeding 4.5 tonnes; or are buses with a gross vehicle mass not exceeding 4.5 tonnes.	This definition has been applied.
The AER defines Heavy commercial vehicles (HCVs) as Motor Vehicles that are registered for use on public roads excluding Elevated Work Platform (HCV)s that: • have a gross vehicle mass greater than 4.5 tonnes; or • are articulated Vehicles; or are buses with a gross vehicle mass exceeding 4.5 tonnes	This definition has been applied.
The AER defines Elevated work platforms (HCV) as Motor Vehicles that have permanently attached elevating work platforms that would be HCVs but for the exclusion of elevated work platforms from the definition of HCV.	This definition has been applied.
The AER defines Elevated work platforms (LCV) as Motor Vehicles that have permanently attached elevating work platforms that are not Elevated work platform (HCV).	This definition has been applied.
The AER defines Non-Network Other Expenditure as all expenditure directly attributable to the replacement, installation, maintenance and operation of Non-network assets, excluding Motor Vehicle assets, Building and Property assets and IT and Communications assets and includes: • non road registered motor vehicles; non road motor vehicles (e.g. forklifts, boats etc.);	This definition has been applied.

Requirements (instructions and definitions)	Consistency with requirements
• mobile plant and equipment; tools; trailers (road registered or not); and • elevating work platforms not permanently mounted on motor vehicles; and mobile generators.	

Actual Information was provided for all variables.

Information provided by Energex's Fleet Management Company SG Fleet Australia has also been relied upon and is considered Actual Information. This information was based on invoice payments per motor vehicle category.

17.2 Sources

Table 17.2 below sets out the sources from which Energex obtained the required information.

Table 17.2: Information sources

Variable	Source
Non-Network Opex Expenditure Motor Vehicles & Other 2008/09 - 2013/14	• Ellipse Financial Reports: – Profit & Loss Reports – Detailed Transaction Reports • Discussions with Department Managers • Operating Expenditure Reports from SG Fleet Australia Pty Limited (Fleet Managers) to allocate cost per Asset Category
Non-Network Capex Expenditure Motor Vehicles & Other 2008/09 - 2013/14	• Ellipse Financial Reports: – Capex Summary Reports – Detailed Transaction Reports • Fleet List including Terminations to cross reference Ellipse Capex reports into Asset Categories (Report provided by SG Fleet Australia Pty Limited) • Previous Annual Capex RIN reports provided by Energex External Reporting team
Non-Network Descriptor Metrics Motor Vehicles 2008/09 - 2013/14	• Ellipse Financial Reports: – Detailed Transaction Reports for Capex Purchases • Fleet List including Terminations to cross reference Ellipse Capex reports into Asset Categories (Report provided by SG Fleet

Variable	Source
	Australia Pty Limited) • Average kms per vehicle category & Units held at end of year data provided by SG Fleet Australia Pty Limited

17.3 Methodology

Below is the Approach that was taken to report the Non-Network Motor Vehicle and Other Expenditure into the Categories as outlined in the Reset RIN.

17.3.1 Approach

Energex applied the following approach to obtain the required information for **Non-Network Motor Vehicles & Other Opex Expenditure f**or 2008/09 - 2013/14:

1) Obtained Profit and Loss reports for all Departments within Fleet, Tools and Equipment and detailed transaction reports for Generator Services, Plant Workshops, Equipment Testing and Laboratory Services from Commercial services (Energex Finance team).

2) Discussed Reports and transactions with Department Managers for Generator Services, Plant Workshops, Equipment Testing and Laboratory Services to determine their nature, i.e. Tools & Equipment Testing vs Plant Testing.

3) Obtained annual expenditure reports from SG Fleet (Energex Fleet Management Company) by Asset Category by Expense type e.g. Repairs, Maintenance, Fuel & Registration. This information was used as the basis for the Asset Category split using the data in the Profit and Loss reports. Any additional costs that could not be attributed to an individual Asset Category were allocated across the Asset Categories using spend.

4) Specific spend that could be allocated to individual Asset Categories are detailed as follows:

   – Generator Services Department operate and maintain Energex mobile generator fleet. Costs associated with Energex Un-Regulated Mobile generator fleet are excluded. Costs were allocated 100% to Non-Network Other.

   – Plant Workshops Department repair, test and maintain Energex's plant e.g. Heavy Commercial Vehicles (HCV) with Elevated Work Platforms, HCV Crane Borers & HCV with Cranes. The units at the end of each financial year were used as the method of allocating costs to these two categories.

   – The Laboratory Services Department test and maintain the Energex meter assets as well as some of Energex's Tools and Equipment. The costs for this department were split using detailed transaction reports based on an analysis of work orders.

- The Equipment Testing Department electrically test and maintain Energex's tool and equipment assets as well as electrically test Heavy Commercial Vehicles (HCV) with Elevated Work Platforms. The costs for this department were split between fleet and tools & equipment using detailed transaction reports based on an analysis of work orders.
- Fringe Benefits Tax (FBT) was allocated 100% to Network Expenditure Car, as all other Motor Vehicle and Other Assets are excluded from FBT.
- Employee Contributions were allocated 100% to Non-Network Operating Expenditure Car. Some employment positions within Energex require the employee to have a vehicle. This vehicle is also available for the employee's private use. For this privilege, the employee pays a contribution to Energex to offset the value of this private use, via salary sacrifice. (Contributions are deducted from operating expenditure)

5) In all instances, depreciation was excluded from the reported opex costs.

6) In all instances, only indirect costs were reported.

In 2012-13 the reduction in the operating expenditure is due to the receipt of an accumulated $1.65M fuel tax credit for the period 2010/11 to 2012-13. For 2013-14 an amount of $1.0M in fuel tax credits was received ($0.2M relating to 2012-13) and an expected credit of approximately $0.6M p.a. every year from 2014-15 onwards.

The ATO has deemed that Energex will be liable for an additional Fringe Benefits Tax related to staff parking at the Newstead corporate office from 2014-15 onwards based on the emergence of commercial parking being available in the near vicinity.

Energex applied the following approach to obtain the required information for **Non-Network Motor Vehicles & Other Capex Expenditure** for 2008/09 - 2013/14:

1) Obtained Capital Summary reports and Detailed Capital Transaction Reports for Fleet Tools and Equipment from Commercial Services (Energex finance team). These reports were used to identify the total of the financial purchases each year.

2) The Detailed Capital Transaction report was used to report the capital purchases, using the unique Fleet Number to identify the applicable asset categories. Due to the requirement to make progress payments on certain assets due to the length of time that these assets take to build and to mitigate some of the suppliers' financial risk, transactions are recorded over several months. Assets that fall into this category were Crane Borers and Elevated Work Platforms.

3) Per Clause 10.5 of the RIN, Energex has incurred $1 million or more in capital expenditure for three classes of assets and these are reported separately. These additional asset classes are Mobile Generators, Trailers and Tools & Equipment. All other Non-Network Other Capital Expenditure is reported as Other.

4) The Complete Fleet list was obtained, including historical Fleet Terminations (sales). This report was used to cross reference the unique Fleet Number to the Ellipse

Reports (for both Unit Additions and Financial Purchase Transactions) to identify the Asset Categories. This report is provided by SG Fleet Australia Pty Limited.

5) The Annual RIN reports were obtained from External Reporting (Energex finance team) to reconcile Fleet, Tools and Equipment Capital Expenditure for the prior periods.

Energex applied the following approach to obtain the required information for **Non-Network Motor Vehicle Annual Descriptor Metrics** 2008/09 - 2013/14:

Annual kilometres:

1) Annual kilometres were calculated using the reported kilometres of all active vehicles during the financial year.

2) If the vehicle was purchased or sold during the financial year, the kilometres were annualised and the unit included in the average, as being active for the full year.

3) The vehicles were split into the Asset Categories, the kilometres totalled. The average was obtained from dividing the total kilometres by the number of vehicles. The raw annualised kilometres and Motor Vehicle data was provided by SG Fleet Australia Pty Limited. The average calculation was performed by the Non System Program Manager.

Units Purchased:

1) Units Purchased were obtained from the Detailed Capital Purchases report for Fleet Assets from Fixed Assets (Energex finance team). This report identifies the Fleet Unit by its unique Fleet Number.

2) The data was reviewed to ensure only one addition was reported per unique Fleet Number. This involved excluding transactions in subsequent financial periods that related to the original commissioning of the asset i.e. accessories purchased separately. Excluded also were transactions relating to Plant rebuilds e.g. Crane Borers and Elevated Work Platforms, as these transactions did not create a new asset.

3) The complete fleet list was obtained including historical Fleet Terminations (sales). This report was used to cross reference the unique Fleet Number to the Ellipse Reports (for both Unit Additions and Financial Purchase Transactions) to identify the Asset Categories.

Leased Units:

1) Energex does not lease any Motor Vehicles.

Number in Fleet:

1) Obtained the Fleet Units at the end of each financial year 2008/09 - 2013/14 from SG Fleet Australia Pty Limited. “Reset RIN Appendix F: Definitions” outlines that the

Number in Fleet should be the average of the units across the financial year. As this data is not available per month, the opening and closing balances were used to average the units across the financial year.

17.4 Estimated Information

Energex has not used estimated data in preparation of this 2008/09 – 2013/14 RIN.

17.5 Explanatory notes

- As mentioned in the Approach for Non-Network Motor Vehicles & Other Capex Expenditure for 2008/09 - 2013/14, careful attention has to be given to the use of this information to calculate unit rates per Asset Category.

- In must be noted that there can sometimes be a small delay between when an invoice is paid and the asset is commissioned. If either of these circumstances span a financial year, a disconnect between financial transactions and physicals (when the asset is actually commissioned) occurs. This has occurred throughout the past five financial years, and is very evident when there is expenditure and no physical in that year i.e.: 2012-13 Network Expenditure HCV – Elevated Work Platforms.

- Information in the RIN will differ from information provided in the CA RIN as Energex employee funded vehicles have been excluded from the calculation as these costs are fully funded by employees and not funded by customers. Also the km’s travelled was adjusted to reflect the average rather than the total as populated in the CA RIN

17.6 Accounting policies

The Accounting Policies that were adopted by Energex during these Regulatory Years covered by the Notice, has not materially changed in nature.

18 BoP 2.6.3 – Non-Network – Property

The AER requires Energex to provide the following information relating to Non-Network Expenditure for years 2008/09 to 2013/14.

- **Buildings and Property Opex and Capex**
- **Other Non-Network Expenditure – Plant and Equipment Capex**
- **Other Non-Network Expenditure – Office Furniture Capex**

Actual Information was provided for all variables.

These variables are a part of Regulatory Template 2.6 – Non-Network Expenditure.

18.1 Consistency with Reset RIN Requirements

Table 18.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 18.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
If expenditure is directly attributable to an expenditure category in this Regulatory Template 2.6 it is a Direct Cost for the purposes of this Regulatory Template. Report all capex and/or opex Direct Costs as required, irrespective of whether any Direct Costs are also classified as Corporate Overheads, Network Overheads or other capex or opex categories. To the extent this results in multiple reporting of expenditures, identify this in accordance with instructions at paragraph 2.3 above.	Energex has reported all figures inclusive of Direct costs and on-costs but excluding overheads as per the Energex CAM approved by the AER.
In relation to the Non-network Other expenditure category, if Energex has incurred $1 million or more (nominal) in capital expenditure over the last five regulatory years for a given type or class of assets (e.g. mobile cranes), Energex must insert a row in the Regulatory Template and report that item separately.	Energex has stated values for “Other – Plant and Equipment” and “Other – Furniture” as their totals are greater than $1 million over the last five regulatory years.
Non-network Buildings and Property Expenditure – Expenditure directly attributable to non-network buildings and property assets including: the replacement, installation, operation and maintenance of non-network buildings, fittings and fixtures. It includes expenditure related to real chattels (e.g. interests in land such as a lease) but excludes expenditure related personal chattels (e.g. furniture) that should be reported under Non-network Other	Energex records furniture as part of fixtures and fittings, however for the Reset RIN they were split out into “Other – Furniture” to align to the AER requirements.

Requirements (instructions and definitions)	Consistency with requirements
expenditure.	

Actual Information was provided in the Buildings and Property service subcategory of Non-Network Expenditure under the asset categories of Buildings and Property, Other – Plant & Equipment and Other – Office Furniture.

18.2 Sources

- EPM – FIN032 Divisional Profit and Loss
- Ellipse – "Accounting Entry Report – incl Proj & WO Desc (ECA90W)"
- Ellipse – "Account Balances by Hierarchy " ECAA01"
- Regulatory Accounts

Table 18.2 below sets out the sources from which Energex obtained the required information.

Table 18.2: Information sources

Variable	Source
Building & Property Expenditure – OPEX ($000's)	Profit and Loss Report by RC 2510 (08/09 to 13/14) & 3600 (08/09 to 12/13) Accounting Entry Report by Activity 62025 and RC 2510 for Network Property Opex activities Accounting Entry Report by Activity 62010 and RC 2510 for Non-Regulated activities
Building & Property Expenditure – CAPEX ($000's)	Regulatory Accounts
Other – Other – CAPEX ($000's) Other – Office Furniture – CAPEX ($000's) Other – Plant & Equipment – CAPEX ($000's)	Fixed Asset Register extract for Newstead project Accounting Entry Report by RC 2510 for Capex Accounting Entry Report by RC 2510 for Capex

18.3 Methodology

18.3.1 Approach

Energex applied the following approach to obtain the required information:

OPEX

1) The profit and loss statement was run from EPM by financial year for opex for the responsibility centres 2510 – Property (08/09 to 13/14) and 3600 - Network Property Data & Coordination (08/09 to 12/13).

2) Non-regulated activities were identified by financial year using the accounting entry report run for activity code 62010 and responsibility centre 2510. As the profit and loss statement includes non-regulated activities, these were subtracted to reflect SCS expenditure only.

Energex applied the following approach to obtain the required information for **Non Network Property Opex** for 2008/09 to 2012/13:

1) Obtained the full Profit and Loss reports for Property (RC 2510) and Asset Management (RC 3600). Also obtained the partial Profit and Loss report for the whole of Energex for elements, Land Tax (5320), Rent & Leases – Land & Buildings (5400) and Rates (5410).

2) Land Tax, Rent & Leases – Land & Buildings and Rates was allocated between Network and Non Network Property Opex expenditure based on the following:

   – Land Tax – The Land Tax for the period 2008/09 to 2012/13 was allocated based on the split of the 2012/13 actual tax bill between Corporate (Non Network), Network and Corporate/Network Shared Sites. The properties allocated to Corporate/Network Shared Sites were assumed to be Corporate in nature as the majority of the site would be used for corporate activities. The split between Network and Non Network is 75.3% and 24.7% respectively. This percentage was applied to period 2008/09 to 2012/13.

   – Rent & Leases – Land & Buildings – Up to 2012, Non Network rent was allocated to Responsibility Centre 2510. Network rent was allocated to responsibility centres apart from 2510. The allocation of Network and Non Network rent for the 2008/09 to 2011/12 is based on the actual spend. In 2012/13, a restructure resulted in all rent expenditure being allocated to responsibility centre 2510. As a result of the restructure which was part way through 2012/13, network rent expenditure was allocated to RC 2510, the portion to be allocated to the Network was based on the average rent per year from RC 3600 for the period 2009/10 to 2011/12.

   – Rates – Up to 2012, Non Network rates was allocated responsibility centre 2510. Network rates were allocated to responsibility centres apart from 2510. The allocation of Network and Non Network rates for the 2008/09 to 2011/12 is based on the actual spend. In 2012/13, a restructure resulted in all rates expenditure being allocated to responsibility centre 2510. As a result of the restructure which was part way through 2012/13, Network rates expenditure was allocated to RC 2510, the portion to be allocated to the Network was based on the average rates per year from responsibility centres other than 2510 for the period 2008/09 to 2011/12.

Energex applied the following approach to obtain the required information for **Non Network Property Opex** for 2013/14:

1) Obtained the full Profit and Loss report for Property (RC 2510).

2) Land Tax, Rent and Leases – Land & Buildings and Rates was allocated between Network and Non Network Property Opex expenditure based on the following:

   - Land Tax – The Land Tax for the period 2013/14 was allocated based on the split of the 2012/13 actual tax bill between Corporate (non Network), Network and Corporate/Network Shared Sites. The properties allocated to Corporate/Network Shared Sites were allocated 50% to Network and 50% to Corporate. The split between Network and Non Network is 78.5% and 21.5% respectively. This is a change in methodology from 2008/09 to 2012/13 based on further analysis provided by the Property Group. The Network Property Opex expenditure relating to Land Tax is identified by the activity 62025 and element 5320.
   - Rent & Leases – Land & Buildings – The Rent & Leases for the period 2013/14 has been identified by the activity 62025 and element 5400. These costs are allocated to the above activity and element by workorder.
   - Rates – The Rates for the period 2013/14 has been identified by the activity 62025 and element 5410. These costs are allocated to the above activity and element by workorder.

The line “Total Indirect Expense excluding On-costs & OH” from Divisional Profit and Loss allocated to “Building and Property Expenditure – OPEX”

The profit and loss took into account the direct expenditure including on-costs. Overheads and depreciation have not been included in the RESET RIN as per the AER approved CAM.

CAPEX

1) The total figure reported for Buildings and Property Capex was taken from the stated figures in the regulatory accounts. These figures included direct expenditure and on-costs but excluded general overheads in accordance with Energex AER approved CAM. These figures were consolidated within Regulatory Template 2.1, for details of this please refer to the Basis of Preparation for that Regulatory Template. These figures also include non-system land purchases.

2) Energex records furniture as part of fixtures and fittings; however as per the AER definition of buildings and property, chattels (e.g. furniture) expenditure is not to be included in the stated figures. These amounts were therefore spilt out into “Other” non-network expenditure.

3) The value for furniture contained in the Buildings and Property figures was calculated in two parts. Firstly an accounting entry report was run to show the furniture expenditure within Energex for each regulatory year. Added to this was then the furniture costs calculated for the "Newstead" project.

4) The furniture costs for the "Newstead" project were calculated separately as the project was run through a building contractor and granular figures were not available for furniture. Another accounting entry report was generated to get the total figure for the "Newstead" project for each financial year. The furniture component of the project was then calculated by using the proportion of furniture asset values to total asset values found for the "Newstead" project in the fixed asset register.

5) The values for both regular Energex furniture capex and that calculated for the "Newstead" project were then added together to give the total for furniture and subsequently subtracted from the Buildings and Property figure. Furniture capex was then stated as "Office Furniture – Capex" in the other expenditure section as the aggregate over 5 years was greater than $1m.

6) Capex expenditure values for Manual Handling System and Generator held in the Fleet part of the RIN have also been reclassified into "Other – Plant and Equipment".

18.4 Estimated Information

Energex has not used estimated data in preparation of this RIN.

18.5 Explanatory notes

OPEX movement between financial years 2009/10 to 2010/12:

- The movement in OPEX is predominately due to increase cost of rent as result of paying rent for two sites in the transition phase to new site (Charlotte St to Newstead) and increased rental charges for new site (Newstead).

Percentage split applied to the breakdown of the Newstead:

- Details of the furniture expenditure were not available as the majority of costs relating to the Newstead project came through the building contractor, i.e. office workstations.

- Chairs and tables were supplied by an independent supplier, but as part of the project completion, a quantity surveyors report was provided to capitalise the project, therefore, the fixed asset register split was used allocate Newstead project between fixtures and furniture.

- Energex records furniture as part of fixtures and fittings. As per the AER definition, furniture was spilt out to "Other".

18.6 Accounting policies

The Accounting Policies that have been adopted by Energex during these Regulatory Years covered by the Notice, has not materially changed in nature.

19 BoP 2.7.1 – Vegetation Management – Descriptor Metrics

The AER requires Energex to provide the following information relating to Table 2.7.1 – Descriptor Metrics By Zone:

For Zone 1

- **Route Line Length Within Zone (Km)**
- **Number Of Maintenance Spans (0's)**
- **Total Length Of Maintenance Spans (Km)**
- **Length Of Vegetation Corridors (Km)**
- **Average Number Of Trees Per Maintenance Span (0's)**
- **Average Frequency Of Cutting Cycle (Years)**

Actual information was provided for Route Line whilst estimated information was provided for all other variables.

These variables are a part of worksheet 2.7 – Vegetation Management.

19.1 Consistency with Reset RIN Requirements

Table 19.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 19.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
"Identify one or more vegetation management zones across the geographical area of Energex's network. To do so consider: a) areas where bushfire mitigation costs are imposed by legislation, regulation or ministerial order; and b) areas of the network where other recognised drivers affect the costs of performing vegetation management work."	Vegetation management zones have been defined as one area as legislation and cutting profiles are consistent across the Energex area. Energex fits inside one Bioregion
"Provide, on separate A4 sheets, maps showing: a) each vegetation management zone; and b) the total network area with the borders of each vegetation management zone."	The map of the Energex vegetation management zone is contained in Appendix 2 – Vegetation Management Zones Map
"For each vegetation management zone identified in 12.1 above, provide in the basis of preparation:	Please refer to section 19.3.2.

Requirements (instructions and definitions)	Consistency with requirements
a) a list of regulations that impose a material cost on performing vegetation management works (including, but is not limited to, bushfire mitigation regulations); b) a list of self-imposed standards from Energex's vegetation management program which apply to that zone; and c) an explanation of the cost impact of regulations and self-imposed standards on performing vegetation management work."	
"If Energex does not record the average number of trees per maintenance span, estimate this variable using one or a combination of the following data sources… b) Field surveys using a sample of maintenance spans within each vegetation management zone to assess the number of mature trees within the maintenance corridor. Sampling must provide a reasonable estimate and consider the nature of maintenance spans in urban versus rural environments in determining reasonable sample sizes."	Field surveys were done to estimate the variables. Please refer to section 19.3.2 for further details.
"A vegetation maintenance span is a span in DNSP's network that is subject to active vegetation management practices in the relevant year. Active vegetation management practices do not include Inspection of vegetation Maintenance Spans"	Demonstrated in section 19.3.2.
"For the purposes of calculating the average number of trees per maintenance span, a tree is a perennial plant (of any species including shrubs) that is: • equal to or greater in height than 3 metres (measured from the ground) in the relevant reporting period; and • of a species which could grow to a height such that it may impinge on the vegetation clearance space of power lines."	Energex has counted trees based solely on the AER's definition.

19.2 Sources

Table 19.2 below sets out the sources from which Energex obtained the required information.

Table 19.2: Information sources

Variable	Source
Route Line Length Within Zone (Km)	ArcGIS

Variable	Source
Number Of Maintenance Spans (0's)	Field Survey ArcGIS
Total Length Of Maintenance Spans (Km)	Field Survey ArcGIS
Length Of Vegetation Corridors (Km)	ArcGIS
Average Number Of Trees Per Maintenance Span (0's)	Field Survey ArcGIS
Average Frequency Of Cutting Cycle (Years)	Contract

19.3 Methodology

Route line length was able to be extracted from the Energex ArcGIS. Energex has calculated all other variables using a statistical sampling methodology. This was performed for both Urban/CBD and Rural areas and across each of the zones to obtain the Reset RIN figures.

19.3.1 Assumptions

A rural area is defined by the level of demand on a network. The following ranges were used to define a rural span:

- Urban/CBD: >300 kVA/km
- Rural: ≤300 kVA/km

The trees counted for the calculation the average number of trees per maintenance span were defined as a perennial plant (of any species including shrubs) that is:

- equal to or greater in height than 3 metres (measured from the ground) in the relevant reporting period; and
- of a species which could grow to a height such that it may impinge on the vegetation clearance space of power lines.

19.3.2 Approach

Definition of Vegetation Management Zones

- Vegetation management zones have been defined as one area as legislation and cutting profiles are consistent across the Energex area. Energex vegetation contracts are based around postcode areas which are modified to create suitable work packages. For previous financial years three vegetation zones were used based upon the predetermined cycle for any given postcode and postcodes with the same cycle time were bundled together. Now that Energex contracts no longer dictate cycle times and these now have flexibility based upon an approved supplier managed program, it is no longer possible or relevant to differentiate Vegetation management zones based on cycle times. Consequently the Energex area has been put into one Vegetation management zone.

- For the map of each zone with respect to the Energex network area please refer to Appendix 2 – Vegetation Management Zones Map.

Route Line Length within each Zone

- The route line length has been extracted from ArcGIS as the point to point line length within each zone (not taking into account multiple circuits). The Rural and Urban/CBD proportions were broken up by the demand on each section of the network in each zone.

Number of Maintenance Spans, Average Number of Trees per Maintenance Span and Total Length of Maintenance Spans

A sample of spans was obtained to survey the spans in Energex's network that are subject to active vegetation management practices, for both Urban/CBD and Rural areas

1) An ArcGIS shapefile was developed to separate the Energex network into Urban/CBD and Rural categories based on the level of demand stated in section 1.1.4 above. This shapefile was then used to calculate the total population sizes of Urban/CBD and Rural spans.

2) From the population sizes a minimum sample size for each population was calculated using the National Statistical Service's "Sample Size Calculator". The final number of sampled spans (2654 spans for both Urban/CBD and Rural) were deliberately higher than the minimum calculated to ensure statistical relevance of the sampling.

3) Spans were then chosen to be surveyed by repeating the following process until the span sample size for both urban/CBD and rural areas had been exceeded.

4) A pole with ID of nnnn (where n = 1 → ∞) was taken. The pole with an ID matching the last prime number before nnnn was then chosen and centred in the middle of the GIS screen. The scale of the map was then adjusted to 1:3000 for urban areas and 1:10000 for rural areas and all spans in that area were included in the sample.

5) Each span was then surveyed by Energex. The span was marked as a maintenance span if the span required active vegetation management. If a span was labelled a maintenance span the number of trees that conformed to the AER definition of a tree were counted.

6) The number of urban/CBD and rural maintenance spans was calculated by multiplying the individual proportions of maintenance spans to non-maintenance spans by their respective population sizes.

7) The total length of maintenance spans was then calculated as the number of maintenance spans multiplied by the applicable average length of a span (calculated as the route line length in each zone and feeder category divided by the respective total number of spans obtained from GIS).

8) The sample average number of trees per vegetation maintenance span for urban/CBD and rural areas was used as the average for the entire population

9) As no tree counts had been done in previous financial years the past figures were estimated. This part of the table was populated by using 13/14 as the base year and reducing proportionally the number of trees based on the change in the route line length of the network. The affected metrics are Number of maintenance spans and total length of maintenance spans.

Length of Vegetation Corridors

1) The length of vegetation corridors was estimated using 100% of the 132/110kV network .

Average Frequency of Cutting Cycle

- Energex recently changed the operating model with aligned suppliers, allowing the supplier to more efficiently manage the utilisation of their resources and make informed decisions in their area of expertise resulting in increased efficiencies and savings for Energex.

- Energex's role transitions from managing and dispatching the program to one of monitoring compliance to required standards and key performance indicators.

1) For the 2013/14 financial year the average cycle cutting time was worked out using a weighted average based upon the first 5 months of the financial year. This is due to the changeover in contract and the difficulty of combining two different programs (one managed by energex and the latter managed by contractors).

2) Table 19.3: Cycle times methodology - Urban and Table 19.4: Cycle times methodology - Rural, over page, show how the cycle times were determined from the 12/13 figures using the weighting of the proportion of each route line length in the different zones:

Table 19.3: Cycle times methodology - Urban

	route line length within zone (km)	Proportion of total	Weighting
1year	7382	84%	7382
2 Year	1158	13%	2316
4 Year	284	3%	1136
Total	8824		10834
Weighted line length divided by Route line length			1.23 years

Table 19.4: Cycle times methodology - Rural

	route line length within zone (km)	Proportion of total	Weighting
1year	7115	42%	7115
2 Year	5943	35%	11884
4 Year	3956	23%	15824
Total	17014		34823
Weighted line length divided by Route line length			2.05 years

The total in years is the figure used for the RIN template.

Legislation and self-imposed standards applicable to Vegetation Management

- Electrical Safety Act 2002
- Electrical Safety (Codes of Practice) Notice 2013
- Electrical Safety Regulation 2013
- Electricity Act 1994

- Electricity Regulation 2006
- Electrical Safety Code of Practice for Working Near Exposed Live Parts
- Mains Asset Maintenance Policy (RED 0296)
- OS119 Vegetation Worker Clearance
- Energex Health and Safety Risk Management (RED 554)

19.4 Estimated Information

Data for all variables excluding route line length are considered estimates.

19.4.1 Justification for Estimated Information

- Energex did not have actual data available for these variables therefore data was estimated.

19.4.2 Basis for Estimated Information

- The field survey method for estimation was used for these five variables as it was the most reliable and timely method available to Energex. Other methods were either not available to Energex (aerial inspection, LiDAR) or did not provide the data granularity required to estimate these variables accurately. For further detail please refer to the methodology section.

20 BoP 2.7.2 – Vegetation Management – Cost Metrics

The AER requires Energex to provide the following information relating to RIN Table 2.7.2 – Expenditure Metrics By Zone:

For Zones 1, 2 and 3

- **Tree trimming (excluding hazard trees) ($'000's)**
- **Hazard tree cutting ($'000's)**
- **Ground Clearance ($'000's)**
- **Vegetation Corridors Clearance($'000's)**
- **Inspection ($'000's)**
- **Audit ($'000's)**
- **Contract Liaison Expenditure($'000's)**
- **Tree Replacement Program Costs ($'000's)**

These variables are a part of Regulatory Template 2.7 – Vegetation Management.

All figures reported are Estimated Information.

20.1 Consistency with Reset RIN Requirements

Table 20.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 20.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Identify one or more vegetation management zones across the geographical area of Energex's network. To do so consider: c) areas where bushfire mitigation costs are imposed by legislation, regulation or ministerial order; and d) areas of the network where other recognised drivers affect the costs of performing vegetation management work.	Vegetation management zones were defined based on the required cutting cycles in each geographical area. These cutting cycles were based upon many conditions including by the growth rate of vegetation within that area.
Provide, on separate A4 sheets, maps showing: c) each vegetation management zone; and the total network area with the borders of each vegetation management zone.	The map of all Energex vegetation management zones is contained in BoP 6.2.1 Vegetation Management Descriptor

	Metrics
For each vegetation management zone identified in 12.1 above, provide in the Basis of Preparation: d) a list of regulations that impose a material cost on performing vegetation management works (including, but is not limited to, bushfire mitigation regulations); e) a list of self-imposed standards from Energex's vegetation management program which apply to that zone; and an explanation of the cost impact of regulations and self-imposed standards on performing vegetation management work.	Please refer to BoP 2.7.1 – Approach.
If hazard tree clearance expenditures are not recorded separately, include these expenditures within tree trimming expenditure and shade the cells for hazard tree clearance black. For the Regulatory Years including and after 2015, Energex must provide data on hazard tree clearance expenditure.	Hazard tree cutting expenditure is captured separately and had been reported in RIN Table 2.7.2
If *ground clearance* works are not recorded separately, include these expenditures within tree trimming expenditure and shade the cells for *ground clearance* black. For the *Regulatory Years* including and after 2015 Energex must provide data on *ground clearance* expenditure.	Ground clearance expenditure has not been reported as this is not recorded separately
Only include expenditure on inspections where Energex inspects solely for the purpose of assessing vegetation. Include inspection expenditure for inspections assessing both Energex's assets and vegetation under maintenance (Regulatory Template 2.8). If Energex does not record expenditure on inspections of vegetation separately, Energex may shade the cells black. For the Regulatory Years including and after 2015, Energex must provide data on inspection expenditure.	Inspection expenditure has not been reported as this is not recorded separately
If auditing of vegetation management work is not recorded separately, include these expenditures within inspection expenditure. If Energex does not record expenditure on audits of vegetation management work separately, Energex may shade the cells black. For the Regulatory Years including and after 2015, Energex must provide data on auditing expenditure.	Audit expenditure has not been reported as this is not recorded separately
Annual vegetation management expenditure across all categories and zones must sum up to the total vegetation management expenditure each year. In Table 2.7.2, add any other vegetation management expenditure not requested in any other part of Regulatory Template 2.7 (or added in Regulatory Template 2.8) in total annual vegetation management expenditure. In the Basis of Preparation, explain the expenditures that have been included in this table.	

Estimated information was provided for all variables.

20.2 Sources

Table 20.2 below sets out the sources from which Energex obtained the required information.

Table 20.2: Information sources

Variable	Source
All Variables	Corvu and MER ECA90W

20.3 Methodology

NAMP (Network Asset Management Plan) line costs were extracted from Corvu for each year of the 5 year period and then mapped to the RIN categories.

This information was then apportioned to the zones based on costs captured for each postcode.

20.3.1 Assumptions

- The costs for each zone were apportioned on a pro rata basis as the NAMP lines were not split by zone.

Tree trimming

- these costs were captured under NAMP lines VG02 (11kV - Vegetation Sector Based Distribution) and VG05 (LV - Customer Requested Vegetation). Costs captured by post code were used to apportion the costs between zones for financial years 2011, 2012 and 2013. As post code information was not captured before this, an average percentage based on the years 2011-2013 was used for the 2009 and 2010 financial years.

Hazard tree cutting

- these costs were captured under NAMP lines VG03 (33kV VTA) and VG04 (11kV VTA). These were then apportioned to each of the zones based on an approximation of trimming in each zone.

Vegetation Corridor Clearance

- these costs were captured under NAMP line VG01 (Transmission clearance zone maintenance), VG07 (Transmission Vegetation Spots) and VG08 (Transmission Survey). This only captures costs for the 132 kV and 110 kV networks. The corridor clearing costs for 33 kV and below lines were apportioned to tree trimming.

Tree replacement costs

- for financial years 2012 and 2013 this is captured under standard jobs linked to NAMP line VG06 (Vegetation – Tree Replacement MOU's). In previous years these costs were captured under the same standard jobs, but linked to NAMP line VG02. For 2009, 2010 and 2011, these costs were excluded from NAMP VG02 and reported as tree replacement costs for this Regulatory Template.

Contractor Liaison Expenditure

- Energex captures these costs as an indirect cost and were therefore not included in this Regulatory Template.

20.3.2 Approach

Definition of Vegetation Management Zones

- Three vegetation management zones were defined within the Energex network.
- These zones were based on the supplier managed programs which were covered under the "Energex Standing Offer for services agreement" with Energex contracted services providers. This groups postcodes into zones based on many factors including the growth rates in each particular area and specifies the required cutting cycles based on these values. These were considered appropriate divisions of the network as the cutting frequency is a key driver of the costs incurred for maintaining each zone.
- For the map of each zone with respect to the Energex network area please refer to Appendix 2 – Vegetation Management Zones Map.

20.4 Estimated Information

- All data was apportioned to the zones based on the actual costs for the financial year and is Estimated Information.

20.4.1 Justification for Estimated Information

Energex has apportioned actual data into the categories required as costs were not captured by zones.

21 BoP 2.7.3 – Vegetation Management – Unplanned Events

The AER requires Energex to provide the following information relating to Table 2.7.3 – Descriptor Metrics Across All Zones - Unplanned Vegetation Events:

- **Number Of Fire Starts Caused By Vegetation Grow-Ins (NSP Responsibility) (0's)**
- **Number Of Fire Starts Caused By Vegetation Blow-Ins And Fall-Ins (NSP Responsibility) (0's)**
- **Number Of Fire Starts Caused By Vegetation Grow-Ins (Other Party Responsibility) (0's)**
- **Number Of Fire Starts Caused By Vegetation Blow-Ins And Fall-Ins (Other Party Responsibility) (0's)**

These variables are a part of worksheet 2.7 – Vegetation Management.

Estimated information was provided for all variables.

21.1 Consistency with Reset RIN Requirements

Table 21.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 21.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In table 2.7.3, fill out the unplanned vegetation events table once, providing the requested information across Energex's entire network.	The variables supplied are across the entirety of the Energex network for the regulatory year.
Energex is not required to provide information requested in table 2.7.3 for Initial Regulatory Years where it does not currently have it, and may shade the cells black. For Regulatory Years 2015 and thereafter, Energex must provide this information.	Data was available and has been supplied for the regulatory year.

Estimated information was provided for all variables.

21.2 Sources

Table 21.2 below sets out the sources from which Energex obtained the required information.

Table 21.2: Information sources

Variable	Source
No of fire starts	Service Call Management Database (SCM) and Network Daily Outage Report until 24/5/14. Focal Point Database post 24/5/14

21.3 Methodology

The number of fire starts was determined from service calls logged in the Service Call Management Database (SCM) and from the Network Daily Outage report (for fire starts not logged in SCM).

This system was replaced when Focal Point was commissioned on 25/5/14. Each service call and outage was analysed and then summed together to obtain how many fire starts there was in each category.

21.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

> Under Queensland legislation Energex is responsible for all vegetation that can affect the electricity network. Consequently there will be zero “other party responsibility” number for all years.

21.3.2 Approach

Energex applied the following approach to obtain the required information:

1) Energex’s Service Call Management Database (SCM) records incoming calls from the public, fire brigade, police, Energex field staff and emergency services. These incoming calls become service requests (SR). All service requests were filtered and extracted from the SCM to obtain the SR jobs involving fire.

2) Each fire SR was then further disseminated to see if vegetation was involved.

3) These SRs are then filtered manually to identify actual fire starts

4) The Network Daily Outage report figures were also analysed as some incidents are not logged in SCM. All outages were filtered to show only those that related to fire

starts and these were added to the totals obtained from SCM to give the final figures.

5) Commencing May 25 all incidents in Focal Point were analysed for fire related jobs in the same process as above.

21.4 Estimated Information

21.4.1 Justification for Estimated Information

While the figures for fire starts have been taken directly from the Energex systems, anecdotal evidence suggests that post incident investigations can identify fires not reported through SCM, the Network Daily Outage Report or Focal Point.

21.4.2 Basis for Estimated Information

The number of fire starts that are not reported through Focal Point, SCM or the Network Daily Outage report cannot be determined as there is no available data for these incidents. The figures taken from these sources are therefore considered to be the best representation of the data able to be generated by Energex.

22 BoP 2.8.1 – Maintenance – Descriptor metrics

The AER requires Energex to provide the following information relating to table 2.8.1:

- **Routine and non-routine asset quantities by maintenance activity and asset category as specified by the AER for each regulatory year.**
- **Routine and non-routine asset quantities inspected and maintained by maintenance activity and asset category as specified by the AER for each regulatory year**
- **The average age of assets by maintenance activity and asset category as specified by the AER for each regulatory year**
- **Routine and non-routine inspection and maintenance cycles by maintenance activity and asset category as specified by the AER**

The following data is estimated:

- **Asset quantity - at year end**
  - **Service Lines – Number of Customers (000'S)**
- **Asset quantity inspected/maintained**
  - **All variables**
- **Average age of asset group**
  - **All variables**
- **Inspection and maintenance cycles – all data**

These variables are a part of worksheet 2.8 – Maintenance

This BoP does not relate to:

Table 2.8.1 – Maintenance Activity: SCADA and Network Control Maintenance which is covered by BoP 2.8.2

Table 2.8.2 – Cost metrics for Routine and Non-Routine Maintenance which is covered by BoP 2.8.3

22.1 Consistency with Reset RIN Requirements

Table 22.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 22.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
For each of the *maintenance* subcategories prescribed in the template, add rows for additional subcategories if these are material and necessary to disaggregate financial or non-financial data, for example, to	No additional rows have been

disaggregate asset groups according to voltage levels or to specify inspection/ maintenance cycles.	added.
For each maintenance subcategory, provide in separate columns the data for inspection cycles and maintenance cycles.	Data has been provided in accordance with this requirement
For the inspection cycle for each maintenance subcategory, express this as ‘n’ in the statement ‘every n years’. For example, if the inspection cycle is ‘every 6 years’, put ‘6’ in the inspection cycle column. Similarly, for the maintenance cycle for each maintenance subcategory, express this as ‘n’ in the statement ‘every n years’. For example, if the maintenance cycle is ‘every 3 years’, put ‘3’ in the maintenance cycle column.	Data has been provided in accordance with this requirement
For inspection and maintenance cycles, asset quantity, and average age of the asset group, use the highest-value (i.e. highest replacement cost) asset type in the asset group as the basis.	Data has been provided in accordance with this requirement
Where there are multiple inspection and maintenance activities, report the cycle that reflects the highest cost activity.	This approach has been used to provide cycle time information
For ‘Asset Quantity’, provide in separate columns: – The total number of assets (population) at the end of the regulatory year, for each asset category – The number of assets actually inspected or maintained during the regulatory year, for each asset category	Both sets of figures have been provided.

The following data is estimated:

- Asset quantity - at year end
  - Service Lines – Number of Customers (000'S)
- Asset quantity inspected/maintained
  - -All variables
- Average age of asset group
  - All variables
- Inspection and maintenance cycles
  - All data

All remaining information is actual data.

22.2 Sources

Table 22.2 below sets out the sources from which Energex obtained the required information.

Table 22.2: Information sources

Variable	Source
Asset quantity – At Year End	NFM/SIFT
Asset quantity inspected/maintained	Corvu POW 302 Reports & EPM POW016
Average age of asset group	NFM
Inspection Cycle	Substation Asset Maintenance Policy (SAMP) and Mains Asset Maintenance Policy (MAMP)
Maintenance Cycle	Substation Asset Maintenance Policy (SAMP) and Mains Asset Maintenance Policy (MAMP)
Service Cable	MARS and the OH Service Program Tracking data (Spreadsheet)

22.3 Methodology

22.3.1 Assumptions

Asset Quantities – At Year End

- Number of Poles (000'S)
  - Customer Poles have been excluded
  - All poles have been reported including streetlight poles
  - All poles have been reported in thousands
- Line Patrolled (Route km) (000'S)
  - Total quantities are reported in Megametres.
  - The conductor data does not include conductors that are in store or held for spares.
  - All lengths stated exclude any vertical components to the conductor, such as sag.
  - The length of each conductor category is the total conductor route length and not each individual phase conductor length, noting:

- 11kV routes predominately consist of 3 conductors.11kV routes also includes some single phase (2 conductors) in its total length.
- LV routes predominately consist of 4 conductors: 3 phases plus neutral; however lengths provided includes all variations.

- Underground Cable Length (Route km) (000'S)
  – Total quantities are reported in Megametres.
  – The cable data does not include cables that are in store or held for spares.
  – All lengths stated exclude any vertical components to the cable, such as vertical tails.
  – The length of each cable category is the total cable route length and not each individual phase.

Asset Quantities – Inspected/Maintained

1) Asset quantities at year end & Asset quantities inspected/maintained alignment:
   – The ‘Asset Quantity at year end’ was extracted from NFM (Network Facilities Management) historical data at the end of each financial year.
   – The Asset quantities were based on Asset Classes which are categories coded in NFM against each piece of equipment in the Energex network.
   – These Asset classes align with particular types of assets that perform the same function.
   – The ‘Asset quantity inspected/maintained’ was derived using NAMP line program codes which were mapped to the AER asset maintenance categories.
   – A NAMP line can contain work performed against multiple asset classes (from NFM).
   – In addition, asset classes (from NFM) can have work performed on them, in multiple NAMP lines.
   – In some instances, work performed against certain types of asset classes (from NFM) will be costed and counted against a NAMP line which has been mapped to a different AER asset maintenance category, based on other assumptions (such as highest expenditure).
   – Hence the method used to calculate the ‘Asset Quantity at year end’ will not always align with the ‘Asset quantities inspected/maintained’ because the asset may have been inspected or maintained against a NAMP line that is mapped to another Maintenance Asset Category.

2) NAMP codes:
   – Energex builds its operating program according to Network Asset Management Plan (NAMP) codes. NAMP codes categorise lower level activities into higher level groups of like type work. For example, ‘NAMP - BZ15 (11kV Circuit Breaker Maintenance)’ contains maintenance work over

many types of 11kV Circuit Breakers all with different criteria and cyclic frequencies.

– The NAMP codes are used for reporting purposes and have been used by Energex for the previous five years for reporting progress to plan and delivery performance.

– Typically, NAMP codes are categorised by Asset Class or created specifically to measure key focus programs.

3) Mapping NAMP codes to RIN categories:

– In order to meet the data requirements in worksheet 2.8, a matrix has been developed to map Energex's NAMP codes to equivalent AER RIN categories.

– Whilst the NAMP codes are not a one-for-one match with the RIN categories they were reasonably aligned.

– Where a single NAMP code related to multiple RIN categories, the RIN category that aligned the closest to the NAMP code was used. For example, 'NAMP - BZ25 (Oil analysis)' contains predominately oil sampling costs for Power transformers and associated tap changers. The NAMP code does, however, also include some costs for regulators and earth transformers. Therefore this NAMP code was mapped to 'Transformers – Zone Substation', as this type of equipment wore the most volume of work.

– Street lighting – Street lighting maintenance was apportioned between major roads and residential roads. Apportionment was based upon asset quantities in each category as at year end.

4) Underground cable maintenance:

– Underground cable maintenance was apportioned between CBD and non-CBD based on the amount of 11kV underground cable in the CBD area relative to total 11kV cable in the network. Table 22.3 provides the apportionment between CBD and non-CBD underground cable.

Table 22.3: Apportionment between CBD and non-CBD underground cable

Cable Category	Length of cable	Percentage of total
CBD	87,328 meters	1.71%
Network	5,116,490 meters	100.00%

22.3.2 Approach

Energex applied the following approach to obtain the required information:

Asset Quantity – At Year End

Pole Tops and Pole Inspection – Number of Poles:

1) A report was extracted from NFM that detailed the poles in the Energex network with the following corresponding information:
   a. The pole material
   b. The original installation year
   c. The number of poles.

2) Poles that have a material type of plastic have been excluded.

Plastic Poles	Quantity
< = 1 kV	13
> 1 kV & < = 11 kV	11
> 22 kV & < = 66 kV	0
> 66 kV & < = 132 kV	0

3) Poles with a site grade code of W have been excluded as this site grade code indicates that the pole is customer owned.

4) For each year the pole quantity was calculated as the sum of poles installed up to and including the appropriate year. These figures have been reported in thousands.

Service Lines – Number of Customers (000'S):

1) The number of service lines for 2014 was calculated for worksheet 5.2 – Asset Age Profile. For details of the methodology used please refer to the relevant basis of preparation for that worksheet.

2) The assets for year-end for service lines were calculated by a count of service cable across the MARS database. Replacements and overhead New Connections data was then reviewed against the current data and the data adjusted accordingly.

3) Quantities of assets inspected/maintained for service lines were based on the number of services maintained during the year, as opposed to the number of customers.

Overhead Assets – Line Patrolled (Route km) (000'S):

1) A report was run from NFM that gave the Energex overhead conductor values for each year broken down by:
   a. Conductor sizing category (Imperial, Metric or Other)

b. The circuit for each conductor

c. The Line Length

All lengths extracted exclude any vertical components to the conductor, such as sag.

2) Excluded from this report were conductors known to be owned by customers. Conductors are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets. When this occurs Energex has captured these conductors. In addition, assets that have been sold to customers and Energex believes that there is a benefit to continue to store this data, the data has not be removed from NFM.

To minimise the effect of captured customer conductors, it has been assumed that where a conductor is connected to only customer assets then that conductor is also customer owned.

Customer Conductor	2009/10	2010/11	2011/12	2012/13	2013/14
Length	8.10	7.52	7.51	8.07	8.13

3) Lengths have been reported in Megameters (km 000's)

Underground Cable Length (Route km) (000'S):

1) A report was run from NFM that gave the Energex underground cables broken down by:

    a. Snapshot point for each year (2009/10 to 2013/14)

    b. Cables constructed voltage is equal to or less than 22kV or greater than 22kV

    c. The cable length

    All lengths stated exclude any vertical components to the cable, such as vertical tails.

2) Excluded from this report were cables known to be owned by customers. Cables are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets, when this occurs Energex has captured these conductors. In addition assets that have been sold to customers and Energex believes there is a benefits to continue to store this data the data has not be removed from NFM.

    To minimise the effect of captured customer cables, it has been assumed that where a cable is connected to only customer assets then that cable is also customer owned.

Customer Cable	2009/10	2010/11	2011/12	2012/13	2013/14
Length (km)	17	16	15	14	14

3) Lengths have been reported in Megameters (km 000’s)

Distribution Substation – Number of Installed Transformers (000'S):

1) A report was extracted from NFM for each year from 2009/10 to 2013/14 that detailed the transformers in the Energex network with the following corresponding information:
    a. Location – Zone or Distribution
    b. Transformer Type – Power or Distribution
    c. Has Customers - Yes or No
    d. Installation Date

    This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

    This report also excludes all assets indicated as customer owned.

2) Report had filters applied to the following category
    a. Location equals Distribution (DIST)

3) Transformer quantities are reported in thousands.

Distribution Substation – Number of Switches (000'S):

1) A report was extracted from NFM that contained an extract for the end of each financial year 2009/10 to 2013/14 that detailed the circuit breakers and reclosers in the Energex network with the following corresponding information:
    a. Snapshot date
    b. Equipment type
    c. Install date

    This report includes all circuit breakers and reclosers that were commissioned at the relevant point in time.

    This report excludes all assets indicated as customer owned.

2) Switch quantity has been reported in the thousands.

Distribution Substation – Other Equipment:

1) The other equipment for distribution substations has been defined as all low voltage circuit breakers.

2) A report was extracted from NFM that contained data for the end of each financial year 2009/10 to 2013/14 for all circuit breakers in the Energex network with the following corresponding information:

    a. Rating of low voltage

    b. Snapshot date

    c. First recorded install date

3) Number of circuit breakers have been reported in the thousands.

Distribution Substation – Number of Distribution Substation Properties Maintained (000'S):

1) A report was extracted from NFM that contained an extract for the end of each financial year 2009/10 to 2013/14 that detailed all sites in the Energex network with the following corresponding information:

    a. Snapshot Date

    b. Sites System Unique Number

    c. First recorded install date

    This report includes all sites that contained a transformer at the relevant point in time and was filtered for distribution transformers only.

    This report excludes all assets indicated as customer owned.

2) Sites have been reported in the thousands.

Zone Substation – Number of Zone Substation Transformers (000'S):

1) A report was extracted from NFM for each year from 2009/10 to 2013/14 that detailed the transformers in the Energex network with the following corresponding information:

    a. Location – Zone or Distribution

    b. Transformer Type – Power or Distribution

    c. Has Customers - Yes or No

    d. Installation Date

    This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

This report also excludes all assets indicated as customer owned.

2) Report had filters applied to the following categories:

   a. Transformer Type equals Power (TR-PW)

   b. Location equals Zone

3) Quantities reported in thousands

Zone Substation – Number of Distribution Transformers Within Zone Substations (000'S):

1) A report was extracted from NFM for each year from 2009/10 to 2013/14 that detailed the transformers in the Energex network with the following corresponding information:

   a. Location – Zone or Distribution

   b. Transformer Type – Power or Distribution

   c. Has Customers - Yes or No

   d. Installation Date

   This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time. This report also excludes all assets indicated as customer owned.

2) Report had filters applied to the following categories:

   a. Transformer Type does not equal Power (TR-PW)

   b. Location equals Zone

   c. Has Customer equal Yes

3) Quantities reported in thousands

Zone Substation – Number of HV Transformers (000'S):

1) A report was extracted from NFM for each year from 2009/10 to 2013/14 that detailed the transformers in the Energex network with the following corresponding information:

   a. Location – Zone or Distribution

   b. Transformer Type – Power or Distribution

   c. Has Customers - Yes or No

   d. Installation Date

This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

This report also excludes all assets indicated as customer owned.

2) Report had filters applied to the following categories:

   a. Transformer Type does not equal Power (TR-PW)

   b. Location equals Zone

   c. Has Customer equal No

3) Quantities reported in thousands

Zone Substation – Other Equipment (000'S):

1) A report was extracted from NFM for each year from 2009/10 to 2013/14 for Connectivity Assets and Non Connectivity Assets:

   a. Snapshot Date

   b. Installation Date

   c. Quantity

   The Connectivity Assets report excluded all assets that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

   Connectivity Asset report also excluded the following assets:

   a. Transformers

   b. Tee Off

   c. Cable Boxes

   d. Circuit Transformers

   e. Cable Joints

   f. Fault Indicators

   g. Switch Fuses

   The Non Connectivity Assets report included the following assets

   a. Ring main units

   b. Battery Banks

Only assets within a Zone or Bulk supply substation have been included in either report.

These reports also exclude all assets indicated as customer owned.

2) Reports were combined

3) Quantities reported in thousands

Zone Substation – Number of Zone Substation Properties Maintained (000'S)

1) A report was extracted from SIFT for each year from 2009/10 to 2013/14 for Bulk and Zone substations that detailed the number of Zone Substations properties that Energex maintains.

2) Quantities reported in thousands

Public Lighting – Number of Public Lights Maintained (000'S)

1) A report was extracted from NFM for each year from 2009/10 to 2013/14 that detailed the streetlights in the Energex network with the following corresponding information:

    a. Snapshot Date

    b. Installation Date

    c. Light Category – Major or Minor

This report also excludes all asset indicated as customer owned.

2) Reports were combined and had filters applied to the following category a. Light Category

3) Quantities reported in thousands

Subtransmission Asset Maintenance – For DNSPs with Dual Function Assets

4) Not applicable to Energex as Energex does not have dual function assets.

Asset quantity inspected / maintained

1) POW302/POW016 Corvu and EPM reports for each year were used to identify the work orders that related to each of the NAMP lines.

2) This data was extracted for activities codes 41100, 41200 and 41600 (2009-10 only), which represent maintenance activities. Data was also extracted from 41500 for activity VG09.

3) Maintenance and inspection data was allocated to the appropriate RIN categories by matching the unit counts for a relevant work order back to its assigned NAMP code, and therefore in turn to the primary maintenance activity in the RIN (based on the mapping of NAMP codes to RIN Asset Categories).

4) Projects/work orders that had not been identified in the POW302/POW016 reports as being associated with specific NAMP codes were reviewed and assigned to NAMP codes where possible based upon the project / work order description.

5) The quantity of assets inspected/maintained for the following categories could not be determined from the POW302/POW016 Corvu and EPM reports as Energex does not capture the required data:

   a. Pole Top, Overhead Line & Service Line Maintenance – Service Lines – Number of Customers

   b. Pole Inspection and Treatment – All Poles – Number of Poles

   c. Overhead Asset Inspection – All Overhead Assets – Line Patrolled (Route Km)

   d. Network Underground Cable Maintenance: By Voltage – LV - 11 to 22 KV – Length (Km)

   e. Network Underground Cable Maintenance: By Voltage – 33 KV and Above – Length (Km)

   f. Network Underground Cable Maintenance: By Location – CBD – Length (Km)

   g. Network Underground Cable Maintenance: By Location – Non-CBD – Length (Km)

   Estimates were calculated for these variables by dividing the “Asset Quantity at Year End” figures in each respective year by the “Maintenance Cycle” value.

6) A zero balance is shown for “Transformers – Distribution” and “Transformers – HV”. This is because asset inspection and maintenance for these assets are conducted as part of the whole zone substation inspection, which covers all assets at a site.

7) A zero balance is shown for “Distribution Substation Switchgear“. Only a new maintenance program was reported in this line which was implemented in 2011/12 (DS09 - retrofit safelink RMU) to replace faulty mechanisms.

Average age of asset group

Pole Tops and Pole Inspection – Number of Poles:

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP5.2.1 for aging calculations.

2) To determine average age for years 2009/10 to 2013/14 the quantities for all proceeding years were removed from the calculation.

3) For example 2009/10 was the average age of all assets from 1910/11 to 2009/10.

Service Lines – Number of Customers (000'S):

1) The number of service lines and their age profile for 2013/14 was calculated for worksheet 5.2 – Asset Age Profile. For details of the methodology used please refer to the relevant basis of preparation for that worksheet.

2) The average age of service lines for prior years was calculated by removing new assets installed in each year (as identified when calculating the asset quantities above) and taking the average age of the remaining assets.

Overhead Assets – Line Patrolled (Route km) (000'S):

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP5.2.1 for aging calculations.

2) To determine average age for years 2009/10 to 2013/14 the quantities for all proceeding years were removed from the calculation.

Underground Cable Length (Route km) (000'S):

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP5.2.1 for aging calculations.

2) To determine average age for years 2009/10 to 2013/14 the quantities for all proceeding years were removed from the calculation.

Distribution Substation – Number of Installed Transformers (000'S):

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP5.2.1 for aging calculations.

2) To determine average age for years 2009/10 to 2013/14 the quantities for all proceeding years were removed from the calculation.

Distribution Substation – Number of Switches (000'S):

1) A report was extracted from NFM that contained an extract for the end of each financial year 2009/10 to 2013/14 that detailed the circuit breakers and reclosers in the Energex network with the following corresponding information:

   a. Snapshot date

   b. Equipment type

   c. Install date

This report includes all circuit breakers and reclosers that were commissioned, at the relevant point in time. This report excludes all asset indicated as customer owned.

2) The average age was then calculated using the installation dates of the assets extracted for each year.

3) All assets with an installation date of 1901 have been ignored in the calculation of average age. This is due to the asset age of 1901 being used when the age cannot be determined for an asset.

Distribution Substation – Other Equipment:

1) The other equipment for distribution substations has been defined as all low voltage circuit breakers.

2) A report was extracted from NFM that contained data for the end of each financial year 2009/10 to 2013/14 for all circuit breakers in the Energex network with the following corresponding information:

   a. Rating of low voltage

   b. Snapshot date

   c. First recorded install date

3) Average age was calculated from the first recorded install date.

Distribution Substation – Number of Distribution Substation Properties Maintained (000'S):

1) A report was extracted from NFM that contained an extract for the end of each financial year 2009/10 to 2013/14 that detailed all sites in the Energex network with the following corresponding information:

   a. Snapshot Date

   b. Sites System Unique Number

   c. First recorded install date

   This report includes all sites that contained a transformer at the relevant point in time. This report excludes all asset indicated as customer owned.

2) All assets with an installation date of 1901 have been ignored in the calculation of average age.

3) Average age was calculated from the first recorded install date.

Zone Substation – Number of Zone Substation Transformers (000'S):

1) A report was extracted from NFM for each year from 2009/10 to 2013/14 that detailed the transformers in the Energex network with the following corresponding information:

   a. Location – Zone or Distribution

   b. Transformer Type – Power or Distribution

   c. Has Customers - Yes or No

   d. Installation Date

   This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time. This report also excludes all asset indicated as customer owned.

2) Report had filters applied to the following categories:

   a. Transformer Type equals Power (TR-PW)

   b. Location equals Zone

3) All assets with an installation date of 1901 have been ignored in the calculation of average age.

4) Average age was calculated from the installation date.

Zone Substation – Number of Distribution Transformers Within Zone Substations (000'S):

1) A report was extracted from NFM for each year from 2009/10 to 2013/14 that detailed the transformers in the Energex network with the following corresponding information:

   a. Location – Zone or Distribution

   b. Transformer Type – Power or Distribution

   c. Has Customers - Yes or No

   d. Installation Date

   This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

   This report also excludes all asset indicated as customer owned.

2) Report had filters applied to the following categories:

   a. Transformer Type does not equal Power (TR-PW)

   b. Location equals Zone

c. Has Customer equal Yes

3) All assets with an installation date of 1901 have been ignored in the calculation of average age.

4) Average age was calculated from the installation date.

Zone Substation – Number of HV Transformers (000'S):

1) A report was extracted from NFM for each year from 2009/10 to 2013/14 that detailed the transformers in the Energex network with the following corresponding information:

   a. Location – Zone or Distribution

   b. Transformer Type – Power or Distribution

   c. Has Customers - Yes or No

   d. Installation Date

   This report excluded all transformers that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

   This report also excludes all asset indicated as customer owned.

2) Report had filters applied to the following categories:

   a. Transformer Type does not equal Power (TR-PW)

   b. Location equals Zone

   c. Has Customer equal No

3) All assets with an installation date of 1901 have been ignored in the calculation of average age.

4) Average age was calculated from the installation date.

Zone Substation – Other Equipment (000'S):

1) A report was extracted from NFM for each year from 2009/10 to 2013/14 for Connectivity Assets and Non Connectivity Assets:

   a. Snapshot Date

   b. Installation Date

   c. Quantity

The Connectivity Assets report excluded all asset that did not contain connectivity, as these assets were not currently in use at the relevant point in time.

Connectivity Asset report also excluded the following assets:

a. Transformers

b. Tee Off

c. Cable Boxes

d. Circuit Transformers

e. Cable Joints

f. Fault Indicators

g. Switch Fuses

The Non Connectivity Assets report included the following assets:

a. Ring main units

b. Battery Banks

Only assets within a Zone or Bulk supply substation have been included in either report.

These reports also exclude all assets indicated as customer owned.

2) Reports were combined

3) All assets with an installation date of 1901 have been ignored in the calculation of average age.

4) Average age was calculated from the installation date.

Zone Substation – Number of Zone Substation Properties Maintained (000'S):

1) A report was extracted from NFM for each year from 2009 to 2014 for Bulk and Zone substations that detailed the installation date of Zone Substations properties that Energex maintains based on the first event associated with a power transformer at the site.

2) Average age was calculated from the installation date.

Public Lighting – Number of Public Lights Maintained (000'S):

1) Reports produced for Table 5.2.1 were used to determine average age. Please refer to BoP 5.2.1 for aging calculations.

2) To determine average age for years 2009 to 2012 the quantities for all proceeding years were removed from the calculation.

Subtransmission Asset Maintenance – For DNSPs with Dual Function Assets:

1) Not applicable to Energex as Energex does not have dual function assets.

Inspection and Maintenance Cycles

1) The cyclic frequencies that Energex have reported are based on current policy requirements obtained from the Substation Asset Maintenance Policy (SAMP) and Mains Asset Maintenance Policy (MAMP). These two policies have been in place for the previous five years. However, as frequencies have been revised over the course of this five-year period, the most current frequencies have been reported.

2) Each piece of equipment used for maintenance is dependent on a range of variables, such as manufacturer, model and insulating properties. As such, each piece of equipment embodies a different frequency associated with routine maintenance. To account for this, Energex has used the frequency of the most common or biggest population of equipment in the network. This is largely due to each year being unique to the volumes of each type of equipment that is triggered for maintenance.

3) If the Asset Category was mapped to a single NAMP line which did not have a routine maintenance or inspection cycles (that is, the NAMP line was for a program completely reactive in nature), a five year cycle was applied to the maintenance cycle and inspection cycle. This was on the basis that all projects would have been visited under other NAMP lines over this period. It should also be noted that some Asset Categories are not explicitly inspected or maintained unless required, for example, 'NETWORK UNDERGROUND CABLE MAINTENANCE: BY VOLTAGE'. For these Asset Categories, the inspection cycle is covered by the Underground feeder asset inspection category. Any maintenance will only occur if it is required.

4) Asset Categories which were mapped to NAMP lines which did not have a routine maintenance cycle (that is, the NAMP lines were for programs that were demand/reactive in nature) but did have an inspection cycle, were given a maintenance cycle the same as the inspection cycle. This is largely due to maintenance being driven through the inspections and not routinely carried out.

5) Asset Categories which were mapped to NAMP lines which did not have a routine inspection cycle (that is, the NAMP lines were for programs that were demand/reactive program in nature) but did have a maintenance cycle, were given an inspection cycle the same as the maintenance cycle. This is largely due to inspections being carried out at the same time of maintenance.

6) Cycle frequencies were reported in the RIN template on the above basis and therefore will not always have associated expenditure (as expenditure may have occurred against another NAMP line which was mapped to another Asset category).

22.4 Estimated Information

The following data is estimated:

- Asset quantity - at year end
  - Service Lines – Number of Customers (000'S)
- Asset quantity inspected/maintained
  - All variables
- Average age of asset group
  - All variables
- Inspection and maintenance cycles
  - All data

All remaining information is actual data.

22.4.1 Justification for Estimated Information

Asset quantity - at year end

Service Lines – Number of Customers (000'S):

- These figures were based on the figures calculated for table 5.2.1 which were also estimated. As such the data stated is considered estimated.

Asset quantity inspected/maintained – all data:

- Certain categories were determined using NAMP lines. As the NAMP lines used to classify assets inspected/maintained are not a direct match to the categories required in table 2.8.1 the data is considered estimated. The NAMP lines are however considered to be the best representation of the categories available to Energex.
- The remaining categories for quantity of assets inspected/maintained could not be determined from the POW302/Corvu reports as Energex does not capture the required data.
- For details of the methodology by which each variable was calculated please refer to the methodology section above.

Average age of asset group

Zone Substation – Number of Zone Substation Transformers (000'S):

- These figures are estimated as when the equipment age is not available then the site age is used as the estimated value.

Zone Substation – Number of Zone Substation Properties Maintained (000'S):

- Energex does not have accurate dates as to when a substation was first used. This had to be inferred from equipment at the site which may or may not have had replacements prior to NFM implementation as only asset history on implementation of NFM is currently known.

All other Maintenance Categories:

- These figures were based on the figures calculated for table 5.2.1 which were also estimated. As such the data stated is considered estimated.

Inspection and maintenance cycles – all data

- The calculation of inspection and maintenance cycles required aggregation of the cycles of many different assets into high level figures. Within this aggregation certain assumptions were made that lead the figures to be estimated.

22.4.2 Basis for Estimated Information

- A large number of the estimates have been based on data calculated for regulatory template 5.2. For the specific methodology please refer to the basis of preparation for that worksheet.

Asset quantity inspected/maintained

- Certain values for assets inspected/maintained have been categorised into the categories required in 2.8.1 by mapping the Energex NAMP lines to the categories required. The values for “Zone Substation Inspection” and “Distribution Asset Inspection” were reallocated as the NAMP lines did not accurately reflect the category being reported.
- The remaining categories were calculated by dividing the “Asset Quantity at Year End” figures in each respective year by the “Maintenance Cycle” value.
- For details of the methodology by which each variable was calculated please refer to the methodology section above.

Inspection and maintenance cycles – all data

- Each piece of equipment used for maintenance is dependent on a range of variables, such as manufacturer, model and insulating properties. As such, each piece of equipment embodies a different frequency associated with routine maintenance. To account for this, Energex has used the frequency of the most common or biggest population of equipment in the network. This is largely due to each year being unique to the volumes of each type of equipment that is triggered for maintenance.

- If the Asset Category was mapped to a single NAMP line which did not have a routine maintenance or inspection cycles (that is, the NAMP line was for a program completely reactive in nature), a five year cycle was applied to the maintenance cycle and inspection cycle. This was on the basis that all projects would have been visited under other NAMP lines over this period. It should also be noted that some Asset Categories are not explicitly inspected or maintained unless required, for example, 'NETWORK UNDERGROUND CABLE MAINTENANCE: BY VOLTAGE'. For these Asset Categories, the inspection cycle is covered by the Underground feeder asset inspection category. Any maintenance will only occur if it is required.

22.5 Explanatory notes

- In the prior Category Analysis (CA) RIN, submitted in April 2014, Energex added and reported data for the six additional variables in table 2.8.1. Variables added are included in the table below:

Maintenance Activity	Maintenance Asset Category	Unit of Measure – Asset Quantity
Zone Substation Inspection	All Substation Assets	Number of Zone substation properties maintained (000's)
Zone Substation Inspection	All Zone Substation Assets	Number of Zone substation properties maintained (000's)
Distribution Asset Inspection	Distribution Substations	Number of Distribution substation properties maintained (000's)
Distribution Pole Mounted Plant Maintenance	All Distribution PMP (Transformers, Regulators, Sectionalisers and Reclosers)	Number of Distribution Transformers, Regulators, Sectionalisers and Reclosers (000'S)
Underground Feeder Asset Inspection	All underground Feeder Assets	Length (KM) (000's)
Pilot Cable Inspection and Maintenance	All Pilot Cables (Copper & Fibre)	Length (Meters)

- The Reset RIN does not provide for these variables to be included in table 2.8.1. Although categories/line items for "Other" Maintenance Activity and "Various Assets" maintenance activities have been included in the templates, due to variations in units of measure for each of the variables previously included it was not feasible to aggregate this information for the purposes of the Reset RIN.
- Expenditure related to these variables has been reported in Reset RIN table 2.8.2 as it was reasonable to combine expenditure incurred across all variables and report

this against one maintenance activity (Various Assets). Further information with regards to this process can be found in Maintenance BoP 2.8.3 (refer to Other Costs Supplementary information).

23 BoP 2.8.2 – Maintenance – SCADA and Network Control Maintenance

The AER requires Energex to provide the following variables relating to Table 2.8.1 Maintenance Descriptor Metrics:

- **SCADA and Network Control Maintenance**
- **Protection Systems Maintenance**

This Basis of Preparation is for the development of the following data for the variables stated above:

- **Total Asset volumes per financial year**
- **Average Age of Asset per financial year**

Estimated Information was provided for all variables covered in this Basis of Preparation.

These variables are a part of worksheet 2.8 – Maintenance.

This BoP does not relate to:

- **Maintenance Quantities for all other maintenance activity and asset category which are covered by BoP 2.8.1**
- **Routine and non-routine asset quantities inspected and maintained for all maintenance activities and asset categories which are covered by BoP 2.8.1**
- **Maintenance Cost Metrics which are covered by BoP 2.8.3**

23.1 Consistency with Reset RIN Requirements

Table 23.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
When Energex must make an estimate because it cannot populate the input cell with actual information, Energex must demonstrate that it has provided the best estimate it can.	Demonstrated in Estimates section below
For 'Asset Quantity', provide in separate columns: (a) the total number of assets (population) at the end of the regulatory year, for each asset category (b) the number of assets actually inspected or maintained during the regulatory year, for each asset category	Table 2.8.1 has been completed in accordance with this requirement

Estimated Information was provided for all variables covered in this Basis of Preparation.

23.2 Sources

Table 23.2 below sets out the sources from which Energex obtained the required information.

Table 23.2: Information sources

Variable	Source
SCADA Network and Control Maintenance (This category was an addition of RTUs, IEDs, Microwave links, DSS Head ends, DSS Radios and Multiplex equipment)	SCADA Base and project documentation, CBMD, ROSS, SAM, CNMG
Protection Systems Maintenance	IPS

23.3 Methodology

Asset Quantity at year End per financial year

SCADA Network and Control Maintenance:

- This was determined by adding up the total number of the below assets for the required financial year using age profile.
  - RTUs;
  - IED;
  - Microwave Links;
  - DSS Head Ends;
  - DSS Radios; and
  - Multiplex equipment (which included MPLS nodes).
- Various techniques were used to create the per financial year age profiles and to correct the data for each financial year, refer to the estimation section below for further details.

Protection System Maintenance:

- This variable was determined by extracting the total installation base from the IPS system and then correcting the data for the relevant financial year by analysing “Discarded” records (units that had been removed or replaced).

Average age of Asset Group per financial year:

- These variables were generated using the per financial year age profile and determining the average age.

Protection System Maintenance:

- These variables were generated using the per financial year age profile and determining the average age.

23.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- For Protection Systems Maintenance, records listed in the IPS database as “Discarded” were considered to be actual units that were replaced.
- Asset that were replaced on failure, were replaced on a one for one basis and were replaced with new equipment for the asset types associated with this Basis of Preparation.

23.3.2 Approach

Energex applied the following approach to obtain the required information for each of the categories stated above:

Total Assets per financial year

1) Age profile data was obtained. It should be noted here that during extraction of data for the 13/14 period a limitation of the IT solution was discovered that artificially reduced the number of reported IEDs. This has been corrected, but will make the extracted data for previous years in consistent with previous RIN statements.
2) The age profile was prepared for the 2012/13 and 2013/14 financial years by correcting the data collected above (relevant records were removed or total numbers estimated).
3) For financial years before 2012/13, installations identified in non-applicable financial years were removed (e.g. for 2011/12 installs from 2012/13 were removed, for 2010/11 both 2011/12 and 2012/13 were removed).
4) Age profiles were corrected by adding any information about units that were replaced in the financial years that were removed.
5) Total assets were calculated by adding up totals identified in the age profile.

Average Age of Asset per financial year

- Using the age profiles per financial year generated above, the average age of the asset base was calculated for each financial year.

Asset age profiles

- The assumptions and Estimated Information used for creating the age profiles are also reported in other Basis of Preparation documents but are reproduced here for continuity.

- Various different methods were used to obtain the required data, below is an explanation for each of the sub-asset categories. These age profiles were then added up to obtain the asset category age profile:
  - Protection relays – report from the IPS database was utilised.
  - RTUs – a review of SCADA control scheme design documentation was performed identifying when hardware was changed. Results were collated into a spread sheet.
  - IEDs – Commissioned records from SCADABase were utilised.
  - Microwave links – The CBMD application was queried to determine the commissioning dates for each link.
  - DSS Head end, radios and repeaters – The ROSS application database was queried to provide an installed / commissioning date.
  - Multiplex – No history information is available in management or finance system for these assets, the total population as at end of 12/13 was estimated and was spread based on when fibre optic cable was installed. Total number of Matrix nodes as reported from the SAM database was then added to the numbers generated.

23.4 Estimated Information

Estimated Information was provided for all variables covered in this Basis of Preparation.

23.4.1 Justification for Estimated Information

For each variable there were two main areas in which the data was required to be estimated:

1) **Estimation of age profiles for previous financial years:**

   It was necessary to estimate installation date of replaced equipment in some cases as no data was available. In these cases the average asset age was utilised to estimate when the assets were likely to have been installed.

2) **Estimation of multiplex age profile (one asset type covered under "SCADA & Network Control Maintenance"):**

No historical records were kept of multiplex installation dates. The installation of the multiplex was estimated by determining when fibre pilot cables occurred and spreading the population based on this age profile.

23.4.2 Basis for Estimated Information

1) **Estimation of age profiles for previous financial years:**

   Where no information was available about the age of a replaced unit, the average asset age was utilised to estimate when the assets were likely to have been installed.

2) **Estimation of multiplex age profile:**

   The installation of the multiplex was estimated by determining when fibre pilot cables occurred and spreading the population based on this age profile

23.5 Explanatory notes

- In the prior Category Analysis (CA) RIN, submitted in April 2014, Energex added and reported data for the six additional variables in table 2.8.1. Variables added that related to SCADA and Network Control Maintenance and/or Protection Systems Maintenance were Pilot Cables.

- The Reset RIN does not provide for these variables to be included in table 2.8.1. Although categories/line items for "Other" Maintenance Activity and "Various Assets" maintenance activities have been included in the templates, due to variations in units of measure for each previous inclusion it is not feasible to aggregate this information for the purposes of the Reset RIN.

- Expenditure related to these variables has been reported in Reset RIN table 2.8.2 as it was reasonable to combine expenditure incurred across all variables and report this against one maintenance activity (Various Assets). Further information with regards to this process can be found in Maintenance BoP 2.8.3 (refer to Other Costs Supplementary information).

- Additional variables unrelated to SCADA and Network Control Maintenance and/or Protection Systems Maintenance but previously added and reported in the CA RIN are detailed in Maintenance BoP 2.8.1.

- Historical information will differ from previously submitted CA RIN submission due to an issue identified in the extraction of data for the 13/14 period. A limitation of the IT solution was discovered that artificially reduced the number of reported IEDs. This has been corrected, but will make the extracted data for historical years reported in the Reset RIN inconsistent with previous RIN statements. This impacts the SCADA Network and Control Maintenance Asset Quantity at Year End and the Average Age of Asset Group.

24 BoP 2.8.3 – Maintenance – Cost Metrics

The AER requires Energex to provide the following information relating to Table 2.8.2:

- **Routine and non-routine maintenance costs by maintenance category as specified by the AER for each regulatory year.**

These variables are a part of Regulatory Template 2.8 – Maintenance

This BoP does not relate to:

- **Maintenance Quantities for all other maintenance activities and asset categories which are covered by BoP 2.8.1**
- **Routine and non-routine asset quantities inspected and maintained for all maintenance activities and asset categories which are covered by BoP 2.8.1**
- **SCADA and Network Control and Protection Systems Maintenance Asset quantities and ages which are covered by BoP 2.8.2**

24.1 Consistency with Reset RIN Requirements

Table 24.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 24.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
For expenditure incurred for the simultaneous inspection of assets and vegetation or for access track maintenance, report this expenditure under maintenance, not vegetation management.	Expenditure has been reported in accordance with this requirement.

24.2 Sources

Table 24.2 below sets out the sources from which Energex obtained the required information.

Table 24.2: Information sources

Variable	Source
Actual Costs by work order	SQL query that extracted data from the Ellipse GL tables
NAMP Line / Work Order alignment	Corvu POW302 Report

Variable	Source
	EPM POW016 Physicals reports

24.3 Methodology

24.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

NAMP codes

- Energex builds its operating program according to Network Asset Management Plan (NAMP) codes. NAMP codes categorise lower level activities into higher level groups of like type work. For example, ‘NAMP - BZ15 (11kV Circuit Breaker Maintenance)’ contains maintenance work over many types of 11kV Circuit Breakers all with different criteria and cyclic frequencies.
- The NAMP codes are used for reporting purposes and were used by Energex for the previous five years for reporting progress to plan and delivery performance.
- Typically, NAMP codes are categorised by Asset Class or created specifically to measure key focus programs.

Mapping NAMP codes to RIN categories

- In order to meet the data requirements in Table 2.8.2, a matrix was developed to map Energex's NAMP codes to equivalent CA RIN categories. Whilst the NAMP codes are not a one-for-one match with the RIN categories they were reasonably aligned.
- In instances where a single NAMP code related to multiple RIN categories, the RIN category that aligned the closest to the NAMP code was used. For example, ‘NAMP - BZ25 (Oil analysis)’ contains predominately oil sampling costs for Power transformers and associated tap changers. The NAMP code does, however, also include some costs for regulators and earth transformers. Therefore, this NAMP code was mapped to ‘Transformers – Zone Substation’, as this type of equipment wore the most volume of work.

Planned and unplanned maintenance

- Energex’s NAMP codes have evolved over the last 5 years as reporting requirements have changed. Energex now has separate NAMP lines for 'planned' and 'unplanned' maintenance work. When a NAMP code was split into ‘Planned’ and ‘Unplanned’, the original NAMP code became the ‘Planned’ NAMP, and the new NAMP code became the ‘Unplanned’ NAMP. These splits predominately occurred in the 2011-12 financial year when reporting against Planned & Reactive work was introduced. Prior to 2011-12, the reactive/unplanned components of these

NAMP codes were aligned to the ‘Routine Maintenance’ costs as per current NAMP mapping.

Public Lighting Maintenance

- Public lighting maintenance was apportioned between major and minor roads based on the amount asset quantities at year end for each road type.

Underground cable maintenance

- Underground cable maintenance was apportioned between CBD and non-CBD based on the amount of 11kV underground cable in the CBD area relative to total 11kV cable in the network. The table below provides the apportionment between CBD and non-CBD underground cable.

	Length of cable	Percentage of total
CBD	87,328 metres	1.71%
Entire network	5,116,490 metres	100.00%

24.3.2 Approach

Energex applied the following approach to obtain the required information:

- POW302/POW016 reports for each year were used to identify the work orders that related to each of the NAMP lines.
- Cost data for the relevant work orders was then sourced using a SQL query that extracted a report from the Ellipse GL tables. The report included the following information:
  - YEAR;
  - DSTRCT_CODE;
  - ACCOUNT_CODE;
  - RESP_CTR;
  - ACTIVITY;
  - PRODUCT;
  - ELEMENT;
  - ELECAT;
  - WORK_ORDER;
  - PROJECT_NO; and
  - AMOUNT.

- This data was extracted for activities codes 41100 (Inspections) and 41200 (Planned Maintenance), which represent maintenance activities. Data was also extracted from 41500 (Vegetation Management) for activity VG09 (Transmission Access Tracks).
- Cost data was allocated to the appropriate RIN categories by matching the cost for a relevant work order back to its assigned NAMP code, and therefore in turn to the primary maintenance activity in the RIN (based on the mapping of NAMP codes to RIN Asset Categories).
- Projects/work orders that had not been identified in the POW302/POW016 reports as being associated with specific NAMP codes were reviewed and assigned to NAMP codes where possible based upon the project / work order description.
- Certain costs reported in the under “Zone Substation Inspection” were identified to relate to “Distribution Asset Inspection”. The costs to be redistributed were determined by firstly analysing the amount within each standard job description under the applicable NAMP line for one year. The analysis of the standard job descriptions then generated a percentage that related to “Distribution Asset Inspection”. This percentage within “Zone Substation Inspection” was then reallocated to “Distribution Asset Inspection” for each year.

24.4 Estimated Information

All data provided in Table 2.8.2 is Estimated Information.

24.4.1 Justification for Estimated Information

- As the NAMP lines used to classify costs are not a direct match to the categories required in Table 2.8.2 the data is considered estimated. The NAMP lines are however considered to be the best representation of the categories available to Energex.

24.4.2 Basis for Estimated Information

- The costs were categorised into the categories required in 2.8.2 by mapping the Energex NAMP lines to the categories required.
- The values for “Zone Substation Inspection” and “Distribution Asset Inspection” were reallocated as the NAMP lines did not accurately reflect the category being reported.

24.5 Explanatory notes

Other Costs Supplementary information

- For the Category Analysis RIN, additional categories were provided to further classify costs. As there is no option to add in these categories for the Reset RIN, Energex has rolled these costs up into “Various Assets” category. Details of the items included in here are in the attached Appendix 4 – Maintenance Other Costs.

25 BoP 2.9.1 – Emergency Response

The AER requires Energex to provide the following information relating to table 2.9.1-Emergency Response Expenditure (Opex):

- **Total emergency response expenditure**
- **Emergency response expenditure attributable to major events by identifying direct costs through a specific cost code for each major event or major storm. Major events most often refer to, but are not limited to, a major storm.**
- **Emergency response expenditure attributable to major event days by identifying**
- **Daily operating expenditure incurred on each date of those major event days and**
- **Summing up the expenditure for each event**

Actual Information was provided for all variables.

These variables are a part of Regulatory Template 2.9 – Emergency Response.

25.1 Consistency with Reset RIN Requirements

Table 25.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 25.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In Table 2.9.1 provide the following - a) total emergency response expenditure b) emergency response expenditure attributable to major events by identifying direct costs through a specific cost code for each major event or major storm. Major events most often refer to, but are not limited to, a major storm. **c)** emergency response expenditure attributable to major event days by identifying daily operating expenditure incurred on each date of those major event days and summing up the expenditure for each event.	The variables supplied in RIN Table 2.9 are across the entirety of the Energex network for each regulatory year.
A Major Event Day SAIDI threshold is calculated for each year using the 2.5 beta method, and any day where the unplanned SAIDI exceeds this threshold is determined to be a Major Event Day.	Demonstrated in section 25.3
Emergency Response is defined in Appendix F of the Reset RIN as:	Energex has reported costs from two activity

Requirements (instructions and definitions)	Consistency with requirements
Costs incurred to restore a failed component to an operational state including all expenditure relating to the work incurred where supply has been interrupted or assets damaged or rendered unsafe by a breakdown, making immediate operations and/or repairs necessary. *Costs of activities primarily directed at maintaining network functionality and for which immediate rectification is necessary. These activities are primarily due to network failure caused by weather events, vandalism, traffic accidents or other physical interference by non-related entities.*	codes, both of which conform to the AER's definition of Emergency Response.

Actual Information was provided for all variables related to Emergency Response Expenditure.

25.2 Sources

Table 25.2 below sets out the sources from which Energex obtained the required information.

Table 25.2: Information sources

Variable	Source
Emergency Response Expenditure by specific date	MER ECA90W
Total Emergency Response Expenditure	Ellipse Report ECAA01

25.3 Methodology

25.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Major Event Days (MEDs) are determined in accordance with the STPIS definition.
- A Major Event Day SAIDI threshold is calculated for each year using the 2.5 beta method, and any day where the unplanned SAIDI exceeds this threshold is determined to be a Major Event Day.
- A major event is defined by the AER as any event that causes a breach of the major event day threshold. The costs reportable in section B are any costs that are recorded specifically against a major event using a work order.

- The Energex activity code 41300 – Corrective Maintenance is defined as:
  - The corrective repair of an asset or installation following an outage or fault. This is limited to the immediate repair work carried out to restore the asset to a temporary/permanent state in which it can perform its required function.
- This activity code as well as the dedicated activity code for emergency response (41400) was used to report costs as the definition above conforms to the AER's definition of Emergency Response stated in Appendix F of the RESET RIN.

25.3.2 Approach

Energex applied the following approach to obtain the required information:

- Costs relating to Emergency Response activities are recorded under the activity headings 41300 and 41400.
- Overall costs for activities 41300 and 41400 were extracted from Ellipse using MER Report ECAA001.
- Major event day (MED) related costs at a work order/ transaction level were extracted using an adapted EPM report (POW005). (Amendment to report was to select specific financial activities, as opposed to default choices of Project / Work Order / Date ranges).
- In both cases above, data was extracted for FY's 2009/10 to 2013/14.
- Expenses were filtered to include only direct costs and on costs (overheads excluded), based on account elements (i.e. account elements 8100, 8101 and 8104 were excluded).
- Costs for identified major events and MEDs were extracted based upon the transaction date of the MEDs, as outlined above. The table below provides a list of the major events and the MEDs that occurred during the period.

Year	Major events	Major event days
2009-10	• Storms struck ENERGEX on 13/10/09 • Storms struck ENERGEX on 22/12/09	• 13/10/2009 • 22/12/2009
2010-11	• Storms struck ENERGEX on 15/12/10 • Storms struck ENERGEX on 16/12/10 • Major flooding of Brisbane and Bremer Rivers between 09/01/11 and 12/01/11 • Storms struck ENERGEX on 18/01/11 • Storms struck ENERGEX on 21/0211	• 15/12/2010 • 16/12/2010 • 09/01/2011 • 10/01/2011 • 11/01/2011 • 12/01/2011 • 18/01/2011

		• 21/02/2011
2011-12	• Storms struck ENERGEX on 17/11/12	• 17/11/2012
2012-13	• Storms and Flooding Impacted ENERGEX Network between 26/01/13 and 29/01/13 • Storms struck ENERGEX 24/03/13	• 26/01/2013 • 27/01/2013 • 28/01/2013 • 29/01/2013 • 24/03/2013
2013-14	• Storms struck ENERGEX on 10/11/2013 • Storms struck ENERGEX on 29/12/2013 • Storms struck ENERGEX on 06/01/2014	• 10/11/2013 • 29/12/2013 • 06/01/2014

- Figures relating to specific major events were captured using unique work orders. The total direct costs and on costs (overheads excluded) were extracted for the major event work orders that had transactions on the specific major event days and are reported in section C:

Dates of Major Event Days	
13/10/2009	17/11/2012
22/12/2009	26/1/2013
15/12/2010	27/1/2013
16/12/2010	28/1/2013
9/1/2011	29/1/2013
10/1/2011	24/3/2013
11/1/2011	10/11/2013
12/1/2011	29/12/2013
18/1/2011	06/01/2014
21/2/2011	

25.4 Estimated Information

No Estimated Information was provided

26 BoP 2.10.1 – Overheads Expenditure

The AER requires Energex to provide the following information relating to Table 2.10.1 - Network Overheads Expenditure:

For the period 2008/09 to 2013/14 period:

- **Network overhead allocation to Standard Control Services:**
  - **Disaggregate network operating costs into six subcategories – network management, network planning, network control and operational switching personnel, quality and standard functions, project governance and related functions, other.**
  - **Other network operating costs previously reported in Regulatory Accounting Statements.**
- **Network overhead allocation to Alternative Control Services:**
  - **Disaggregate network operating costs into six subcategories – network management, network planning, network control and operational switching personnel, quality and standard functions, project governance and related functions, other.**
  - **Other network operating costs previously reported in Regulatory Accounting Statements.**
- **Allocation to Negotiated Services.**
- **Allocation to Unregulated Services.**
- **Network overhead allocation to Capitalised Overheads:**
  - **Disaggregate network operating costs into six subcategories – network management, network planning, network control and operational switching personnel, quality and standard functions, project governance and related functions, other.**
  - **Other network operating costs previously reported in Regulatory Accounting Statements.**

The AER requires Energex to provide the following variables relating to Table 2.10.2 - Corporate Overheads Expenditure:

- **Allocation to Standard Control Services:**
  - **Corporate overhead expenditure previously reported in Regulatory Accounting Statements not included in any other overhead subcategory.**
- **Allocation to Alternative Control Services:**
  - **Corporate overhead expenditure previously reported in Regulatory Accounting Statements not included in any other overhead subcategory.**
- **Allocation to Negotiated Services.**
- **Allocation to Unregulated Services.**
- **Capitalised Overheads:**
  - **Corporate overhead expenditure previously reported in Regulatory Accounting Statements not included in any other overhead subcategory.**

All information is Estimated Information.

These variables are a part of Regulatory Template 2.10 – Overheads.

26.1 Consistency with Reset RIN Requirements

Table 26.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 26.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In responding to this Notice Energex must for the Previous Regulatory Control Period, the Current Regulatory Control Period and for Forecast Information, allocate costs in accordance with Energex's Applicable Cost Allocation Method. In responding to this Notice Energex must apply the classification of services in the framework and approach paper for the Previous Regulatory Control Period, the Current Regulatory Control Period and for Forecast Information. (a) Note this section 1.1 does not relate to the value of Energex's regulatory asset base prior to 1 July 2015.	Energex has complied with this requirement when completing regulatory template 2.10. For details please refer to the section below for 26.3 Methodology.
Report overhead expenditure before it is allocated to services or direct expenditure, and before any part of it is capitalised.	Expenditure in Table 2.10.1 is consistent with the requirement for 'overhead expenditure before allocation'. The expenditure presented is before allocation and capitalisation.
Energex must disaggregate network operating costs into the following six subcategories: (a) network management (b) network planning (c) network control and operational switching personnel (d) quality and standard functions (e) project governance and related functions (f) other.	Appendix 5 explains the classification of services into the below categories- • Network management; • Network planning; • Network Control; • Operational Switching • Quality and Standard Functions; and • Project Governance.

Requirements (instructions and definitions)	Consistency with requirements

For the avoidance of doubt, the following expenditures must be provided in regulatory template 2.10:
 	
(a) Regulatory template 2.10.1 Network Overhead – If Energex has previously reported network operating costs in its Regulatory Accounting Statements, Energex must report these under network overhead in regulatory template 2.10.1:
 	
i. network management
 	
ii. network planning
 	
iii. network control and operational switching personnel
 	
iv. quality and standard functions (including standards and manuals, compliance, quality of supply, reliability, network records (GIS), and asset strategy (other than network planning)
 	
v. project governance and related functions (including supervision, procurement, works management, logistics and stores)
 	
vi. other (including training, OH&S functions, network billing, and customer service).
 	
The six subcategories above are mandatory subcategories in network overhead.
 	
(b) Regulatory template 2.10.1 Network Overhead – For other network operating costs that Energex previously reported in its Regulatory Accounting Statements and are not included in the six mandatory subcategories above, Energex must report these under network overhead in regulatory template 2.10.1. These expenditures include, but are not limited to:
 	
i. meter reading
 	
ii. advertising/marketing
 	
iii. Guaranteed Service Level (GSL) payments
	Network overheads expenditure for 2008/09 to 2013/14 has been categorised into the following subcategories:
	
	Mandatory
	
	• Network Management
	• Network Planning
	• Network Control and Operational Switching Personnel
	• Quality and Standard Function
	• Project Governance and related Functions
	  – Logistics and stores (POW Material Management)
	  – Procurement
	  – Project Governance – Supervision
	  – Project Governance – Works Management
	• Training and Development
	• OHS
	• Customer Services
	
	Optional
	
	• Meter Reading, Network Billing, & Metering Support
	• DSM Initiatives
	• Levies
	• Network Property
	
	Corporate overheads expenditure for 2008/09 to 2013/14 has been categorised into the following subcategories:
	
	• Office of CEO
	• Legal and Secretariat
	• Audit
	• Strategy and Regulation
	• Human Resources
	• Finance
	• Business Support Services
	• Business Operations and Performance
	• Field Support Services

Requirements (instructions and definitions)	Consistency with requirements
iv. National Energy Customer Framework (NECF)-related expenses v. feed-in tariffs vi. demand management expenditure vii. levies (c) Regulatory template 2.10.2 Corporate Overhead – For corporate overhead expenditure that Energex previously reported in its Regulatory Accounting Statements and are not included in any other overhead subcategory, Energex must report these under corporate overhead in regulatory template 2.10.2. These expenditures include, but are not limited to: i. office of the CEO ii. legal and secretariat iii. human resources iv. finance v. regulatory vi. insurance vii. self-insurance viii. debt raising costs ix. equity raising costs x. non-network IT support.	• Stakeholder Engagement and Management • Other Operating • Corporate Restructuring • IT and Communications • Property • Fleet • Debt Raising Costs
If there is any overhead expenditure that is capitalised, explain in the Basis of preparation document(s), why it is capitalised.	Energex's capitalisation policy explains that Energex's core business is the construction, maintenance and operation of the electricity distribution network in South East Queensland. In the operation of its business, Energex incurs a range of support costs that are not

Requirements (instructions and definitions)	Consistency with requirements
	directly attributable to individual distribution services or activities. As these costs support the direct activities associated with both the construction and maintenance of the electricity network, Energex has employed a rational and systematic approach, to attribute these support costs to operating and capital activities, which is described in its Cost Allocation Methodology (CAM). In accordance with Energex's CAM, approved by the AER, regulated overheads are allocated to distribution services(capital and operating) based on direct spend incurred on each service as this reflects a strong correlation with the consumption of the underlying overhead expenditure.

Estimated information was provided for all variables.

26.2 Sources

- For backcasting overheads, information was sourced from Ellipse general ledger reports, regulatory account workpapers and Energex's corporate modelling tool, Cognos.

26.3 Methodology

- Reclassification of services in accordance with the AER's Framework & Approach has resulted in changes to the allocation of overheads, which have been allocated consistent with Energex's new CAM.

- Backcasting for Classification of Services (CoS) and CAM resulted in changes to all initially sourced data reported in template 2.10. The approach that was taken to backcast overhead expenditure into the categories in the Reset RIN is outlined below.

26.3.1 Approach

Energex applied the following approach to obtain the required information:

1) Obtained general ledger (GL) reports that provide account balances for expenses, detailing the nature of items via codes that identify the group that incurred the expense (Responsibility Centre), the work being performed (Activity), and the type of expense (Element).

   Expense accounts were then mapped based on the definitions of Network Overheads and Corporate Overheads included in Appendix F of the Reset RIN and the associated guidance provided in Appendix E of the Reset RIN.

   Note: some items identified by Energex as direct costs and reported accordingly in the Annual Performance (AP) RIN, needed to be mapped to Network Overheads for Reset RIN reporting. These included Network Operations, DSM Initiatives, Levies, Customer Service, Meter Reading and Network Billing functions.

2) Functional areas are per the mandatory categories defined in the Reset RIN and additional categories as provided for in Energex's current annual RIN. Mapped the account codes:

   a. That specifically related to SCS, ACS, unregulated services or balances not relevant for backcasting purposes (such as Solar PV FiT, costs of asset disposals reported separately, internal allocations and intercompany consolidation entries);

   b. As network or corporate overhead;

   c. Into functional areas (which represent the sub-categories of network and corporate overheads), principally on Responsibility Centre and Activity, as detailed in Appendix 5;

   d. As capitalisable (costs allocated to direct control services based on direct spend, in accordance with Energex's approved CAM) or non-capitalisable costs (these costs remain as 100% operating expenditure and are allocated to services in accordance with Energex's approved CAM).

3) Identifying direct costs prior to backcasting by service classifications and nature (eg: SCS capex, ACS opex etc)

4) Identifying direct costs for CoS changes by service and nature. As mentioned above, some were identifiable via account codes while others required estimates

5) Restating total direct costs including CoS changes by service and nature

6) Identifying associated overhead costs:

   a. For those reclassified via account code, identifying the associated overheads from the account code;

   b. For estimated costs, applying the relevant year's proportion of overheads to direct costs prior to backcasting (identified in step 3) above) to the amount – e.g.: if overheads were $300M and direct costs were $1,000M, 30% was added as overhead; and

c. Aggregating the reclassified overheads then balancing back to the total overheads prior to backcasting.

7) Identifying the proportions of backcast overheads attributable by service and nature for each year – for example:

Year	Major events
ACS capex	5%
ACS opex	6%
SCS capex	66%
SCS opex	22%
Unregulated opex	1%

8) Developing a new Cognos data set to reallocate costs in accordance with CoS and CAM changes. This involved:

   a. attributing specific costs to SCS, ACS or unregulated services using the mapping in step 2 above. Costs allocated to unregulated services included DSM expenditure separately funded by a State government grant and therefore treated as unregulated.

   b. Entering the relevant proportions from step 7 above to determine pooled costs to be allocated to:

      i. SCS & ACS opex only

      ii. SCS & ACS capex and opex

   c. Generating data for network and corporate overhead sub-categories by year, including capitalised network and corporate overheads for SCS and ACS

   (Note: only capitalised overheads for SCS are required and included in template 2.10 Overheads, however capitalised overheads for ACS also are required for template 2.1 Expenditure Summary)

   d. Generating data for network and corporate overheads by year, by categorisation needed for template 2.12 Input Tables

9) Compiling the Cognos data into the format required for template 2.10 Overheads and template 2.12 Input Tables

10) Including manual adjustments for items not included in the Cognos data, specifically for:

   a. Capitalised oncosts;

b. Levies;

c. Debt raising costs; and

d. Unregulated costs for materials and fleet oncosts, and costs allocated in accordance with Energex's approved CAM using a three factor method (3FM).

SCS capitalised overheads equal the figures identified in Table 2.1.1 of Template 2.1 Expenditure Summary.

26.4 Estimated Information

Due to the application of backcasting requirements to all variables all information reported is considered estimated information.

26.4.1 Justification for Estimated Information

Estimated information is defined in the Reset RIN as:

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

Accordingly, backcast information for CoS and CAM changes must meet this definition as it is:

- not materially dependent on information in Energex's historical accounting records;
- inherently based on judgements and assumptions for which there could be valid alternatives.

In addition, sections 3.6 and 3.7 of Appendix C: Audit and Review to the Reset RIN indicates that backcast information is subject to review consistent with that required for estimated information.

26.4.2 Basis for Estimated Information

The basis for backcasting estimates is detailed in the methodology section above.

26.5 Explanatory notes

- Solar PV Feed-in Tariffs are subject to a jurisdictional scheme from 1 July 2015 and have therefore been excluded from Template 2.10 – Overheads for back-casting purposes.

- Corporate Overheads for Corporate Restructuring began in 2012 as a result of Energex's conscious effort to reduce costs and employee numbers. This has resulted in the payment of termination benefits.

- Corporate Overheads for Debt Raising Costs eventuated with the new Determination in 2011.

- Expenditure incurred in relation to network property has been identified as a specific network overhead. Prior to 2013 this expenditure was captured in a dedicated department. In 2013 an organisational restructure occurred rationalising the property functions, with the network property function being transferred to the corporate property department. The department previously responsible for network property changed its focus and is now mapped to Quality Standards and Functions. The expenditure associated with network property for 2013 has been separately identified.

27 BoP 2.11-1 – Labour

The AER requires Energex to provide the following information relating to Table 2.11.1 – Labour Cost Metrics per Annum:

Historical and Forecast information for the period 2008/09 – 2013/14 relating to

- **ASLs (Average Staffing Levels)**
- **Total Labour Cost**
- **Average Productive Working Hours per ASL**
- **Stand Down Occurrences per ASL**

This information is required to be provided for all labour categories as defined by the AER, split into Corporate Overheads, Network Overheads and Direct Network Labour.

Estimated information was provided for all years.

The AER requires Energex to provide the following information relating to Table 2.11.2 – Extra Labour Descriptor Metrics for Current Year (2013/14):

- **Average Productive Work Hours Per ASL - Ordinary Time**
- **Average Productive Work Hours Hourly Rate Per ASL - Ordinary Time**
- **Average Productive Work Hours Per ASL - Overtime**
- **Average Productive Work Hours Hourly Rate Per ASL – Overtime**

This information is required to be provided for all labour categories as defined by the AER, split into Corporate Overheads, Network Overheads and Direct Network Labour.

Estimated information was provided for all years.

These variables are part of worksheet 2.11 – Labour.

27.1 Consistency with Reset RIN Requirements

Table 27.1 below demonstrates how the information provided by Energex is consistent with each of the requirements relating to this Basis of Preparation.

Table 27.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Only labour costs allocated to the provision of standard control services should be reported in the labour cost sections of Regulatory Template 2.11. Labour used in the provision of contracts for both goods and services, other than contracts for the provision of labour (i.e. labour hire contracts) must not be reported in these regulatory templates.	Energex general ledger (GL) system (Ellipse) uses GL account codes to capture transaction information. This includes the department (Responsibility Centre), functions being performed (Activity), product or service delivered to external customer and nature of income or expense (Element). Energex uses the GL code to extract out only

Requirements (instructions and definitions)	Consistency with requirements
Energex must break down its labour data (both employees and labour contracted through labour hire contracts) into the Classification Levels provided in Regulatory Template 2.11. Energex must explain how it has grouped workers into these classification levels.	the labour related cost (Element) and standard control services (a combination of Responsibility Centre and Activity) figures. Energex labour categories allocated (via employee timesheets) to GL transactions have been mapped to the relevant labour categories required in the Reset RIN. For further details please refer to the Approach section below.
Labour related to each classification level obtained through labour hire contracts may be reported separately on separate lines to employee based labour. If Energex wishes to do this they should add extra lines in the regulatory template below each classification level for which it wishes to separately report labour hire.	Costs related to labour hire are separately identified in the table.
Quantities of labour, expenditure, or stand down periods should not be reported multiple times across labour regulatory templates. However, labour may be split between Regulatory Templates (for example one worker could have half of their time allocated to corporate overheads and half of their time to network overheads).	All figures were split between the mutually exclusive categories of corporate overheads, network overheads and network direct. The method of allocation is noted in Section 27.3 Methodology.
The ASLs for each classification level must reflect the average Paid FTEs for each Classification Level over the course of the year.	Energex converted labour hours captured in the GL system into ASLs which represents the average Paid ASLs for each Classification Level over the course of each year.
'Per ASL' values are average values per ASL in each classification level. For example, the average productive work hours per ASL would equal the total productive work hours associated with labour in the classification level divided by the number reported in Annual Totals – ASLs for the classification level (i.e. the number of ASLs in the classification level).	This has been calculated as per the AER's instructions. For further details please refer to section 27.3.2 Approach.
Stand down periods must be reported against the relevant classification level in the regulatory template containing the relevant labour. For example, a stand down of an electrical line apprentice would be reported against the apprentice classification level in the Total network direct internal labour costs	This was calculated as per the AER's instructions. For further details please refer to 27.3.2 Approach.

Requirements (instructions and definitions)	Consistency with requirements
regulatory template.	

Estimated information was provided for all years in the template.

27.2 Sources

Table 27.2 below sets out the sources from which Energex obtained the required information.

Table 27.2: Information sources

Variable	Source
Table 2.11.1 – Labour Cost Metrics per Annum	
ASLs	Ellipse (GL, payroll and HR information), Standard labour rates and hours (Energex Business Performance & Analysis)
Total Labour Cost – Actual, Budget and Forecast	Ellipse (GL), Standard labour rates and hours (Energex Business Performance & Analysis)
Average Productive Working Hours per ASL	Standard labour rates and hours (Energex Business Performance & Analysis)
Stand Down Occurrences per ASL	Ellipse (HR)
Table 2.11.2 – Extra Labour Descriptor Metrics for Current Year (2013-14)	
Average Productive Work Hours Per ASL - Ordinary Time	Standard labour rates and hours (Energex Business Performance & Analysis)
Average Productive Work Hours Hourly Rate Per ASL - Ordinary Time	Ellipse (GL)
Average Productive Work Hours Per ASL - Overtime	Standard labour rates and hours (Energex Business Performance & Analysis), Ellipse (GL)

Variable	Source
Average Productive Work Hours Hourly Rate Per ASL – Overtime	Ellipse (GL)

The following reports were extracted from the Ellipse system:

- General ledger balance ($ and hours) by labour category / element;
- General ledger transactions of 9 hour break by labour category; and
- General ledger balances ($) of labour hire.

The following reports were extracted from the Human Resource Information System (HRIS) or provided by the Energex Payroll and HR Systems Team:

- Labour category breakdown of labour hire;
- 9 days and 10 days fortnightly work arrangement breakdown of internal labour;
- HRIS – Monthly Active FTE report; and
- Stand Down occurrences.

The following reports were extracted by the Energex Business Performance & Analysis team:

- Budget – Standard Labour available hours by labour category; and
- Budget – Standard Labour rate by category.

27.3 Methodology

Information in the Labour Regulatory Template was based on actual transactions from the General Ledger and payroll system. Minor adjustments were made where appropriate to comply with requirements set by the AER.

27.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Training cost and FBT comprise an immaterial portion of labour cost.
- FTE data in relation to 9 hour break payments equates to number of stand down occurrences for ASLs.

27.3.2 Approach

Energex applied the following approach to obtain the required information:

1) The following GL labour data was obtained from Ellipse:

   a. Dollars
   b. Hours
   c. Ordinary time
   d. Overtime
   e. GL code
   f. Labour category

2) Each GL code was mapped into the required categories as set out in the table below. The classifications are consistent with Energex's proposed Cost Allocation Methodology (CAM) for the forthcoming regulatory control period. The classification of the GL codes can be seen in Table 27.3 below:

Table 27.3: Classification of GL codes

AER Reset RIN Category	Energex GL Code
Corporate overhead	Corporate support cost
Network overhead	Metering Customer Call Centre DSM Direct Levies Network operations
Network direct	SCS Direct Opex SCS Direct Capex*(Excludes all fleet and material on-costs and general overhead)*

ASLs and Total Labour Costs

1) Each Energex labour category extracted from Ellipse was classified into the required categories as set out in Table 27.4 over page. The standard annual available hours/FTE for each labour category (Energex Business Performance & Analysis team) was then used to convert the total labour hours into ASLs.

Table 27.4: Labour classification categories

		2013/14	2014/15
Energex	AER	Annual Hours/annum	Annual Hours/annum
ADMN	SUPPORT STAFF	1,692	1,675
APPR	APPRENTICE	1,593	1,579
CONT	PROFESSIONAL	1,692	1,675
ELEC	SEMI PROFESSIONAL	1,593	1,579
EXE1	MANAGER	1,523	1,509
EXE2	SENIOR MANAGER	1,611	1,597
NEXE	PROFESSIONAL	1,692	1,675
PARA	SEMI PROFESSIONAL	1,692	1,675
PROF	PROFESSIONAL	1,692	1,675
PWKR	UNSKILLED WORKER	1,505	1,491
SPEB	MANAGER	1,692	1,675
SPVR	SEMI PROFESSIONAL	1,692	1,675
SYSO	SEMI PROFESSIONAL	1,692	1,675
TECH	SKILLED ELECTRICAL WORKER	1,505	1,491
EMT	EXECUTIVE MANAGER	1,611	1,597

It is noted that Executive managers, as specified in the Reset RIN, are contained in the Energex labour classification EXE2. These ASLs were manually extracted to comply with the reporting requirements set by the AER. The remainder of EXE2 was then classified as Senior Managers.

2) Standard available hours are based on 2013-14 budgeted hours for historical information. These hours are then adjusted for ASLs on the 9 day fortnightly work arrangement.

3) Once labour costs had been calculated the termination payments for each year were added. These termination payments were obtained from HR data and were added to the labour cost figures for each year.

Training cost and FBT were not in the labour cost as this data was unavailable for inclusion. However, it is noted that these costs were immaterial for purpose of this report.

Average Productive Work Hours per ASL

1) Total available hours were converted into productive hours by subtracting the known hours of training assigned to each employee type. The following figures were subtracted from the available hours to convert to productive hours:
    a. Apprentice: 315 hours per year
    b. All other labour categories: 24 hours per year i.e. three days

Stand down Occurrences per ASL

1) Transactional data for enforced 9 hour breaks (which constitutes a stand down occurrence) can be identified in the HR payroll system using an earning code for

2008-09 to 2013-14. The number of stand down occurrences was calculated as the frequency of transactions in each labour category per year.

2) 9 hour break transactional data cannot be identified by service classification as this information is only captured by employee. In addition, the 9 hour break transactions are recorded as overhead costs in Energex's payroll system, however these transactions relate to employees working across Corporate Support, Network Overheads and Network Directs. If the figures for Network Overhead ASLs only were used as the denominator rather than total headcount, it will significantly distort the stand-down occurrence per ASL.

3) To report this measure, Energex has adopted the following formula to calculate the figures for Stand Down Occurrences per ASL:

$$\frac{Number\ of\ Stand\ Down\ Occurances}{Energex\ Total\ FTEs}$$

The following is noted in relation to the above:

- Some journals within the GL data were processed without labour categories. Where this occurred, the balance was proportionally allocated to all labour categories (except for the highlighted balances in Table 27.5 below) within each functional area.

Table 27.5: Exceptions to proportionally allocated labour categories

$M	2009	2010	2011	2012	2013	2014
Corporate Overhead	0.2	0.1	-0.5	-0.1	0.1	-1.8
Network Overhead	-0.2	2.2	-7.2	-15.3	-17.2	-8.9
Network Direct	-0.7	-0.3	0.4	9.5	9.4	5.8

- The manual adjustments for Network Direct Costs in 2012 and 2013, as well as all categories in 2014 were primarily related to semi-professional and skilled electrical workers and consequently the adjustment was not applied to other labour categories.

- Some journals within the GL data were processed without labour hours. To ensure consistency in the calculation of the Hourly Rate per ASL for Ordinary and Overtime, the journals were excluded from the calculations of Ordinary and Overtime hourly labour rates.

- Redundancy Expenses were excluded from the calculation of hourly labour rates as these expenses cannot be linked to hours worked per employee and would distort the data if included.

Labour Hire

1) Labour hire data was captured using the GL code element 4920 for the years 2012-13 and 2013-14. Prior to 2012-13, the 4920 GL code was also used for contractors and therefore cannot be relied upon to accurately reflect the labour hire costs.

2) The 2012-13 and 2013-14 actual amounts (with the removal of capital expenditure which was specifically identified as contractor costs) were used as the best representation of Energex's labour hire spend. The 2012-13 year was de-escalated for the years 2008-09 to 2011-12 using the contractor escalation percentage per the Energex budget (which is a function of CPI and the AER determination escalation factors).

3) Labour hire data is not disaggregated by labour category, therefore the labour hire figures for Network Overheads and Network Directs for each year were split into the labour categories using a pro-rata methodology based on the known total labour costs in each year (80% Support Staff/10% Professional/10% Unskilled Worker – source: HR). The labour hire dollars calculated were divided by the productive ordinary time labour rate to obtain hours for each labour category.

Table 2.11.2 - Extra Descriptor Metrics For Current Year (2013/14)

The following process was used to calculate extra descriptor metrics for the 2013/14 regulatory year:

1) General Ledger transactions were extracted to show both the Ordinary and Overtime components of labour dollars and hours.

2) The average productive work hours per ASL for ordinary hours was extracted directly for each labour category based on standard available hours.

3) Average productive work hours hourly rate for ordinary time was calculated as the total costs for ordinary time divided by the number of ASLs to give an average cost per ASL. This was then divided by the average productive work hours per ASL extracted above to give an hourly rate per ASL.

4) Average productive work hours hourly rate per ASL for overtime was calculated as the total overtime cost extracted from Ellipse divided by the total overtime hours worked.

27.4 Estimated Information

For all financial years (2008-09 to 2013-14), estimates were used.

27.4.1 Justification for Estimated Information

For the financial years 2008-09 to 2013-14, the Energex General Ledger system captured cost and hours by labour category. However, some journals to labour costs were processed without any labour category information. This coupled with definition changes in Energex's labour categories across last five years necessitated the use of estimated information.

27.4.2 Basis for Estimated Information

ASL by labour category

- As ASLs are required to be split into the functions they perform, the ASLs were calculated based on current available hours per ASL. With changes in mix of employees, operational requirements and work practices from year to year, the calculated ASLs are estimated information.

Cost and hours by labour category

- Where material journals were processed in the years 2008-09 to 2013-14 without labour categories (see details in approach section), the balance was proportionally allocated to selected labour categories. This may result in some inconsistencies of hourly rates between corporate overhead, network overhead and network direct.
- When journals are processed between General Ledger codes, reclassification of corresponding hours might not have been consistently applied resulting in some inconsistencies of hourly rates between labour categories.

Labour Hire

- As contractor costs have been included in the labour hire account code transactions prior to 2012-13, the first four years have been estimated, based on 2012-13 actual transactions, adjusted for information (see details in approach section).

Stand down occurrence

- Energex assumed that the ASL data in relation to the quantity of 9 hour break payments equates to the number of stand down occurrences for ASLs.

27.5 Explanatory notes

ASL movement between financial years

Senior manager/Manager:

- In 2013 Energex standard labour costing classified EXE2 into a different labour cost category resulting in higher senior ASLs per current mapping. It also explains the corresponding reduction in managers in 2013.

Managers and Semi Professional:

- In 2012, the increase is due to extra Program of Work initiatives i.e. Job ready, program governance, network operations, projects and works.

Termination Payments

- In the 2011-12 and 2012-13 financial year there were significant termination payments incurred by Energex (approximately $9 million in 2011-12 and $51 million in 2012-13). This has the effect of increasing the labour expenditure for those years.
- $22.4M of termination payments were incorporated into labour information for 2013-14.

Reporting where relevant labour classifications are unavailable

In some instances, Energex's mapping of labour categories to AER classifications produced results which are unable to be populated against the relevant classifications. This applies for Corporate Overheads, Network Overheads and Network Directs, which have been populated into the Master templates as detailed below.

- Within Corporate Overheads, figures reported for Intern/Junior Staff/Apprentice represent data that would have otherwise been reported as:
  - Skilled Electrical Workers
  - Unskilled Workers
  - Apprentices (Intern/Junior Staff/Apprentice previously only reported Apprentices)
- Within Network Overheads, figures reported for Intern/Junior Staff/Apprentice represent data that would have otherwise been reported as:
  - Skilled Electrical Workers
  - Skilled Non-Electrical Workers
  - Apprentices (Intern/Junior Staff/Apprentice previously only reported Apprentices)
- Within Network Directs, figures reported for Skilled Non Electrical Workers represent data that would have otherwise been reported as:
  - Senior Manager
  - Managers
  - Professionals
  - Semi professionals
  - Support staff

These classifications were applied as there was no data (or limited data in the case of Apprentices) already populated against these classifications and therefore doesn't distort the figures reported.

Changes affecting Network and Corporate split from 2009-2013

- Following the preparation of the Regulatory Proposal, a few Network Overhead Functions were reclassified to Corporate Overhead. This is not a change in the AER requirements but instead reflects better allocation of the Overhead expenditure. It also creates alignment between the Labour and Overheads Reset RIN allocations.
  - The reclassifications involve expenditure from the following functions:
  - Business Operations and Performance
  - Business Support Services
  - Field Support Services
  - Fleet

Backcasting impacts as a result of changes to the Cost Allocation Method and Classification of Services

The Reset RIN requirements instruct that the information reported for the years 2009-2014 be ‘backcast’ to be reported on the same basis as the Regulatory Proposal. The Regulatory Proposal reflects changes to both the Cost Allocation Method and Classification of Services. The reclassification of services involves expenditure for the following services:

- Rearrangement of Assets
- Metering Connections
- Subdivisions – Real Estate Development

Reclassifications of services have resulted in changes to the allocation of overheads, which have been allocated consistent with Energex’s new CAM.

28 BoP 2.12.1 – Input tables

The AER requires Energex to provide the following information in Regulatory Template 2.12 Input Tables:

- **Direct material costs**
- **Direct labour costs**
- **Contract costs**
- **Other costs**
- **Related party contract cost**
- **Related party contract margin**

For each of the following Service Categories, split by designated subcategories:

- **Overheads**
- **Fee Based Services**
- **Quoted Services**
- **Non-Network**
- **Vegetation Management**
- **Routine Maintenance**
- **Non-routine Maintenance**
- **Augmentation**
- **Connections**
- **Emergency Response**
- **Public Lighting**
- **Metering**
- **Replacement**

Estimated Information was provided for:

- **Overheads**
- **Routine Maintenance**
- **Non-routine Maintenance**
- **Vegetation Management**
- **Augmentation**
- **Connections**
- **Public Lighting**
- **Metering**
- **Replacement**
- **Fee-based Services**
- **Quoted Services**

Actual Information was provided for all other elements.

These variables are a part of Regulatory Template 2.12 – Input Tables

A separate Basis of Preparation has been prepared for the disaggregation of related party costs for all variables.

28.1 Consistency with Reset RIN Requirements

Table 28.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 28.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In responding to this Notice Energex must for the Previous Regulatory Control Period, the Current Regulatory Control Period and for Forecast Information, allocate costs in accordance with Energex's Applicable Cost Allocation Method. In responding to this Notice Energex must apply the classification of services in the framework and approach paper for the Previous Regulatory Control Period, the Current Regulatory Control Period and for Forecast Information. (a) Note this section 1.1 does not relate to the value of Energex's regulatory asset base prior to 1 July 2015.	Energex has complied with this requirement when completing regulatory template 2.12. For details please refer to Basis of Preparation 0.1 – "Backcasting". The impacted categories on this template were as follows: • Overheads • Fee-Based Services • Quoted Services
Direct costs Operating or capital expenditure directly attributable to a work activity, project or work order. Consists of in-house costs of direct labour, direct materials, contract costs, and other attributable costs. Excludes any allocated overhead.	Energex has reported all direct costs in accordance with the categories specified in RIN Table 2.12, which balance to the regulatory accounts where applicable.
Direct materials Materials are the raw materials, standard parts, specialised parts and sub-assemblies required to assemble or manufacture a network/non-network asset or to provide a network/non-network service. *Direct materials* costs are attributable to a specific asset or service, cost centre, or work order, and exclude materials provided under external-party contracts. Includes: • the cost of scrap • normally anticipated defective units that occur in the ordinary course of the production process • routine quality assurance samples that are tested to destruction	Refer above.

Requirements (instructions and definitions)	Consistency with requirements
• the net invoice price paid to vendors to deliver the material quantity to the production facility or to a point of free delivery.	
Direct labour cost *Labour cost* attributable to a specific asset or service, cost centre, work activity, project or work order. *Labour costs* The costs of: • Labour hire; and • Ordinary time earnings; and • Other earnings, on-costs and taxes; and • Superannuation.	Refer above.
Contract A legally binding contract.	Refer above.

Actual Information was provided for:

- All Non-Network figures; and
- All Emergency Response figures

Note: Some Non-Network information was provided by the Energex fleet management company, SG Fleet Australia Pty Limited, which was based on invoice payments per motor vehicle category – this was considered Actual information.

Estimated information was provided for:

- Overheads
- Routine Maintenance
- Non-routine Maintenance
- Vegetation Management
- Augmentation
- Connections
- Public Lighting
- Metering

- Replacement
- Fee-Based Services
- Quoted Services

28.2 Sources

Opening data for overheads, fee based services, quoted services was sourced directly from the annual regulatory accounts, work papers and/or from general ledger reports.

Table 28.2 below sets out the sources from which Energex obtained the required information.

Table 28.2: Information sources

Variable	Source
Network Overheads	Annual regulatory accounts and/or general ledger reports.
Corporate Overheads	Annual regulatory accounts and/or general ledger reports.
Fee Based Services and Quoted Services– 2008/09 & 2009/10	• Annual regulatory accounts work papers
Fee Based Services and Quoted Services – 2010/11 to 2013/14	• General ledger reports
Non-Network – IT and Communications	• SPARQ Solutions information based on invoices issued to Energex; • Accounting Entry Report per Ellipse; • Profit and Loss for SPARQ Solutions division from EPM for Cost of Sales, Telecommunications, Asset Usage Fee, Finance Fee & SLA • Capex expenditure per Regulatory accounts less Client Devices per Accounting Entry Report • Profit and Loss MOPEX RC 2310, account 4940 for 08/09 • Profit and Loss MOPEX RC 1025, account 4940 for 09/10 to 12/13 • Profit and Loss MOPEX RC 1020, account 4940 for 13/14 • Mapping table for allocation of cost element to

Variable	Source
	the Input Tables categories (Appendix 3 – Cost Element Mapping to Input Table Categories). Provided by Regulatory Accounting division.
Non-Network – Motor Vehicles	• Ellipse Financial Reports: – Profit & Loss Reports – Capex Summary Reports – Detailed Transaction Reports • Fleet List including Terminations to cross reference Ellipse Capex reports into Asset Categories (Report provided by SG Fleet Australia Pty Limited) • Previous Annual Capex RIN reports provided by Energex External Reporting team • Discussions with Department Managers • Operating Expenditure Reports from SG Fleet Australia Pty Limited (our Fleet Managers) to allocated cost per Asset Category • Mapping table for allocation of cost element to the Input Tables categories (Appendix 3 – Cost Element Mapping to Input Table Categories) provided by Regulatory Accounting division.
Non-Network – Buildings and Property	• Profit and Loss Report by RC 2510 (08/09 to 13/14) & 3600 (08/09 to 12/13) • Accounting Entry Report by Activity 62025 and RC 2510 for Network Property Opex activities • Accounting Entry Report by Activity 62010 and RC 2510 for Non-Regulated activities • Regulatory Accounts • Mapping table for allocation of cost element to the Input Tables categories (Appendix 3 – Cost Element Mapping to Input Table Categories) Provided by Regulatory Accounting division.
Non-Network – Other (Combined Motor Vehicle and Property)	**Property 'Other'** • Fixed Asset Register extract for Newstead project • Accounting Entry Report by RC 2510 for Capex Accounting Entry Report by RC 2510 for Capex • Mapping table for allocation of cost element to the Input Tables categories (Appendix 3 – Cost Element Mapping to Input Table Categories).

Variable	Source
	Provided by Regulatory Accounting division. **Motor Vehicles Other** • Ellipse Financial Reports: – Profit & Loss Reports – Capex Summary Reports – Detailed Transaction Reports • Fleet List including Terminations to cross reference Ellipse Capex reports into Asset Categories (Report provided by SG Fleet Australia Pty Limited) • Previous Annual Capex RIN reports provided by Energex External Reporting team • Discussions with Department Managers • Operating Expenditure Reports from SG Fleet Australia Pty Limited (our Fleet Managers) to allocated cost per Asset Category • Mapping table for allocation of cost element to the Input Tables categories (Appendix 3 – Cost Element Mapping to Input Table Categories). Provided by Regulatory Accounting division.
Vegetation Management	• Corvu EPM and MER ECA90W
Routine Maintenance	• SQL query that extracted data from the Ellipse GL tables • Corvu POW 302 Reports and EPM POW016
Non-routine Maintenance	• SQL query that extracted data from the Ellipse GL tables • Corvu POW 302 Reports and EPM POW016
Augmentation	• EPM
Connections	• Corvu Fin027, Ellipse (MER ECAA01), EPM
Emergency Response	• EPM • POW005 Transaction Report
Public Lighting	• MER ECA90W, Corvu, EPM

Variable	Source
Metering	• Peace, Ellipse, ACS Quote Mode, Business Objects Reports
Replacement	• EPM

28.3 Methodology

Overheads, Fee Based and Quoted Services

- Energex has sourced the required information from the annual regulatory accounts, work papers and/or supporting general ledger reports. Information was then categorised based on the relevant cost elements.
- Following the acquirement of this initial data, it was necessary to apply backcasting methodology in order to comply with the RIN guidelines which require that Energex allocate costs in accordance with Energex's Cost Allocation Method (CAM) for the forthcoming regulatory control period and apply the classification of services (CoS) in the AER's framework and approach paper for the for the forthcoming regulatory control period.

All other elements

- The figures in RIN Table 2.12 are based on the figures generated for the relevant regulatory templates. These figures were then distinguished between the required input table categories by mapping the cost elements within the base data. The mapping table can be found in Appendix 3 – Cost Element Mapping to Input Table Categories.

28.3.1 Assumptions

- Information is based on the audited annual regulatory accounts, work papers and/or supporting ledger reports.
- Energex has consistently reported direct costs throughout the Reset RIN. This means that overhead expenditure recorded against the overheads variables in table 2.12 has not been duplicated via inclusion in expenditure reported against other variables within the table.
- It is assumed that the "Major Storms" category within the Emergency Response section relates to the total costs reported in section B of Regulatory Template 2.9.

28.3.2 Approach

Overheads

- For years when information couldn't be sourced directly from the annual regulatory accounts, Energex has mapped the detail from general ledger reports to the required categories.

- There is a direct relationship between the individual cost elements and the required categories, which is established via the element hierarchy. For example, the cost element for ordinary time labour is under the hierarchy for employee benefits, which maps to the category for Direct Labour Cost. A summarised mapping table is provided in Appendix 3 – Cost Element Mapping to Input Table Categories.

- Separate mapping to Network Overheads and Corporate Overheads is in accordance with the mapping applied for Regulatory Template 2.10.

- For 2008/09 and 2009/10, balances were adjusted to be consistent with those reported in Template 2.10 which reflects the figures in the annual regulatory accounts each year.

- For the period 2010/11 to 2013/14, a proportional allocation method was applied to facilitate the assignment of regulatory reporting adjustments to the respective cost categories. This was because adjustments for regulatory purposes were undertaken at the total dollar value amount and not at the individual cost element. The allocation was applied based on the direct proportion of expenditure reported in the general ledger for the respective categories.

Backcasting

- Following the acquirement of this initial data, it was necessary to backcast overhead expenditure in order to comply with the RIN guidelines which require that Energex allocate costs in accordance with Energex's Cost Allocation Method (CAM) for the forthcoming regulatory control period and apply the classification of services (CoS) in the AER's framework and approach paper for the for the forthcoming regulatory control period. The detailed methodology used for this backcasting is included in BoP 2.10.1 – Overheads.

Fee Based and Quoted Services

- Primary data was obtained by cost element from the annual regulatory accounts work papers and/or supporting general ledger reports.

- There is a direct relationship between the individual cost elements and the required categories, which is established via the element hierarchy in the general ledger Chart of Accounts (COA). For example, the cost element for ordinary time labour is under the hierarchy for employee benefits, which is mapped to the category for Direct Labour Cost. A summarised mapping table is provided as Appendix 3 – Cost Element Mapping to Input Table Categories.

2008/09 and 2009/10

- Alternative Control-equivalent services for the previous Determination period (classified as Excluded Distribution Services from 2008 to 2010) were not further sub-classified as Fee-Based or Quoted Services in the annual regulatory accounts. Energex determined this sub-classification for the CA RIN based on a review of the work papers for the regulatory accounts for the relevant years. In most cases:
  - Business-to-Business (B2B) services provided to retailers were classified as Fee Based; and
  - Price on Application (POA) services and Infrastructure Projects (conducted under State Government infrastructure development initiatives, which are similar in nature to Rearrangement of Network Assets) were classified as Quoted Services.
- Exceptions relate to services which can be both Fee-Based and Quoted, dependant on the nature. For example, simple services for Temporary Connections are Fee-Based whereas complex services are Quoted Services.
- Amounts reconcile to those reported in the annual regulatory accounts excluding overheads.

2010/11 to 2013/14

- The distribution of direct costs by activity and cost elements was generated from general ledger reports. This information was then reconciled back to the annual regulatory accounts, work papers and/or supporting documents.

Backcasting

- Following the acquirement of this initial data, it was necessary to backcast expenditure in order to comply with the RIN guidelines which require that Energex allocate costs in accordance with Energex's Cost Allocation Method (CAM) for the forthcoming regulatory control period and apply the classification of services (CoS) in the AER's framework and approach paper for the for the forthcoming regulatory control period.
- The detailed methodology used for this backcasting, as it applies to fee-based and quoted services expenditure, is included in BoP 0.1 – Backcasting.

Non-Network - IT and Communications

- The IT and Communications figure was calculated as the sum of the following items from Regulatory Template 2.6 broken down into each input table category (for details of the methodology for figures stated in 2.6 please refer to the relevant Basis of Preparation):
- Client Device Expenditure Opex ($'000) – The expenditure from SPARQ Solutions to Energex is allocated to "Contractor Costs" as per the conversion table found in Appendix 3.

- Client Device Expenditure Capex ($'000) – The identified client devices were grouped by cost element and allocated as per the conversion table found in Appendix 3.The grouping showed some client devices being allocated to "Contractor Costs". These costs were related to the purchase of "ToughBooks" however they were purchased through SPARQ Solutions. These costs were reallocated to "Direct Materials Costs" as this reflects the correct category of spend.

- Recurrent Expenditure Opex ($'000) – These items were reconciled to the SPARQ Solutions accounts and allocated based as per the conversion table provided in Appendix 3. Total "Contractor Costs" for Recurrent Expenditure is calculated less the "Contractor Costs" Client Device Expenditure. Negative numbers seen for "Other Costs" reflect transfers to Metering Dynamics of telecommunication costs and the transfer of small capex purchases.

- Recurrent Expenditure Capex ($'000) is calculated as the difference between total Energex ICT Capex as recorded in the Regulatory accounts less the client devices capex calculated above. The identified non-client devices were grouped by element and allocated as per conversion table provided in Appendix 3.

- The percentage split between "Direct Material Costs", "Direct Labour Costs", "Contractor Costs" and "Other Costs" by financial year was obtained from the mapping of all ICT capex data (less client devices) using the table in Appendix 3. These percentages were then applied to the recurrent expenditure identified in Regulatory Template 2.6. This was to ensure that the figures reconciled back to the regulatory accounts. The effect of the percentage allocation is immaterial to the total figures.

- Non-recurrent Opex ($'000) – The expenditure was allocated to "Contractor Costs" as per conversion table provided in Appendix 3.

Non-Network - Buildings and Property

- The Buildings and Property figures were calculated as the sum of the following items from Regulatory Template 2.6 broken down into each input table category (for further details of the methodology for figures stated in Regulatory Template 2.6 please refer to the relevant Basis of Preparation):

- Building & Property Opex – The expenditure from Regulatory Template 2.6 was allocated between "Direct Material Costs", "Direct Labour Costs", "Contractor Costs" and "Other Costs" as per the conversion table provided in Appendix 3. Non-regulated and network expenditure was not included in the calculations.

- Buildings & Property Capex – The figure contained data extracted directly for Buildings and Property from the accounting entry reports as well as an allocation of fixtures and fittings from the Newstead project.
  - The Buildings and Property Capex figure in Regulatory Template 2.6 (less that for Newstead fixtures and fittings) was broken up into the required categories. This was done by firstly calculating the proportion of Direct Materials, Direct Labour, Contract and Other Costs in each year based on the totals found in

the accounting entry reports. These percentages were then multiplied by the figures found in Regulatory Template 2.6.

– The figures included direct expenditure and on-costs but excluded general overheads in accordance with Energex AER approved CAM. These figures also include non-system land purchases and exclude the amounts separated into other expenditure for furniture.

– The Newstead Property & Building Expenditure Capex ($'000) figures were then added to the numbers calculated above. The percentages were identified for "Direct Material Costs", "Direct Labour Costs", "Contractor Costs" and "Other Costs" by element by financial year for the Newstead project as per conversion table provided in Appendix 3. The percentages were applied against the fixtures and fittings portion of the Newstead project (as identified in the Basis of Preparation for Regulatory Template 2.6). The figure calculated for Newstead fixtures was then added to the Buildings and Property Capex figure.

Non- Network - Other Expenditure

- The other expenditure figures related to "Property" were calculated as the sum of the items below. The first two items relate to the "Other – Office Furniture" in Regulatory Template 2.6. The third item relates to the "Other – Plant and Equipment" figure in Regulatory Template 2.6.

- Newstead Other Expenditure Capex ($'000) – The furniture portion of the Newstead project was calculated in Basis of Preparation 2.6. These figures were then split between "Direct Material Costs", "Direct Labour Costs", "Contractor Costs" and "Other Costs" using the same percentages used above in the Newstead fixtures and fittings portion of Buildings and Property Capex. The value calculated for "Other" was allocated to the "Other" expenditure category required in Regulatory Template 2.12.

- Non-Newstead Other Expenditure Capex ($'000) – The percentage split between "Direct Material Costs", "Direct Labour Costs", "Contractor Costs" and "Other Costs" was identified by element by financial year based on total furniture capex from the accounting entry reports and using the conversion table provided in Appendix 3. The percentages were applied to the Other Furniture (Non-Newstead) Expenditure identified in each financial year.

- Other Plant & Equipment Expenditure Capex ($'000) – The expenditure relating to Manual Handling Systems and Generator were allocated to "Other Expenditure - Contractor Costs" as this expenditure was paid through contractors undertaking the Geebung development.

- All "Other" expenditure reported for Motor Vehicles in Regulatory Template 2.6 was classified into Direct Materials, Direct Labour, Contract and Other Costs using the cost element mapping table found in Appendix 3. Once classified the following variables were added together to give a total for other expenditure:

  – Other Non-Network Expenditure Fleet Tools & Equipment

  - Other Motor Vehicles - Mobile Generators
  - Other Motor Vehicles - Trailers
  - Other - Tools & Equipment
  - Other

- The “Other” expenditure total figure was then calculated as the sum of the “Other” items for both Motor Vehicles, ICT and Property.

Non-Network - Motor Vehicles Expenditure

- Figures for motor vehicles expenditure was calculated for Regulatory Template 2.6. For details of the calculation please refer to the Basis of Preparation for Regulatory Template 2.6.
- The figures for motor vehicles were calculated from data that classified each expense by the cost element. These cost elements were used along with the mapping table found in Appendix 3 to classify the motor vehicles expenses into the categories required in Regulatory Template 2.12. Each category (Cars, Light Commercial Vehicles, Elevated Work Platforms and Heavy Commercial Vehicles) was then summated to give the final figure per Direct Materials, Direct Labour, Contract and Other Costs for each year.

Vegetation Management

- The vegetation management costs were developed by zone within Regulatory Template 2.7 – Vegetation Management. For full details of the development of the vegetation management figures please refer to the Basis of Preparation for Regulatory Template 2.7.
- The vegetation management costs were developed from reports which detailed the figures by cost element. These cost elements were used in conjunction with the mapping table found in Appendix 3 to split the total costs for each region into Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs per year.

Routine and Non-routine Maintenance

- Routine and non-routine maintenance figures were developed from the Energex Network Asset Management Plan (NAMP) codes within Regulatory Template 2.8. For full details please refer to the Basis of Preparation for maintenance cost metrics.
- The maintenance costs were extracted with Energex cost elements when being developed for Regulatory Template 2.8. This allowed each expense to be mapped into Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs using the mapping table with Appendix 3. The cost for each year was then summated to obtain the routine and non-routine maintenance figures in Regulatory Template 2.12.

Augmentation

- Figures for augmentation expenditure broken down into the required categories (Substations, Feeders, Lines etc.) were calculated for Regulatory Template 2.3 – Augex in RIN Table 2.3.4. These figures were generated from project costs that were grouped into the required categories. For full details please refer to the Basis of Preparation for RIN Table 2.3.4.

- The costs for each classified project were able to be broken down into their respective cost elements. These were then used with the mapping table in Appendix 3 to generate Direct Material Cost, Direct Labour Cost, Contract Cost and Other Cost figures per project. The project level figures were then summated using the project classifications used in RIN Table 2.3.4 to produce the figures for the input tables Regulatory Template.

Connections

- The figures for connections were apportioned to labour, material, contract and other cost categories based on each respective years expenditure for 2008/09-2012-13, under financial activity codes C2010, C2510, C2550 and C2570 (less gifted assets). The expenditure figures were able to be broken up into the required cost categories; however the four activity codes only accounted for 92.8% of total connections spend over the 5 year period 2008-09 to 2012-13 financial years. An apportionment method was applied to the regulatory information based on percentage of totals extracted from the project ledger listing to ensure the total for connections expenditure balanced to total connections expenditure over the 5 year period.

- For 2013/14 the capital costs were split by cost category by running a project cost report from EPM for the list of projects reported. The expenditure figures were able to be broken up into the required cost categories; however the total costs in the project ledger do not match the regulatory account values. As such an apportionment method was applied to the regulatory information based on percentage of totals extracted from the project ledger listing to ensure the total for connections expenditure balanced to regulatory accounts.

Emergency Response

- The figures for “Major Storms” in Regulatory Template 2.12 were calculated using the figures found in section B of Regulatory Template 2.9 – Emergency Response. These numbers in Regulatory Template 2.9 were generated by extracting all expenditure relating to specific major event work orders. The costs under each of these work orders were able to be split into cost elements and mapped to the Direct Material Cost, Direct Labour Cost, Contract Cost and Other Cost categories using the table in Appendix 3.

- The figures for “Major Event Days” in Regulatory Template 2.12 were calculated using the figures found in section C of Regulatory Template 2.9 Emergency Response. The figures in Regulatory Template 2.9 were calculated by breaking down the cost of each day into their respective costs elements and mapping them to Direct Material Cost, Direct Labour Cost, Contract Cost and Other Cost categories using the table in Appendix 3.

Public Lighting

- For periods 2008/09 – 2012/13 the figures for public lighting costs in the input tables Regulatory Template were based on the calculations done for the total cost figures in RIN Table 4.1.2. A report was run from Mincom Ellipse that detailed the project expenditure against the following financial activity codes:
  - C2560 – CWDA Public Lighting
  - C3560 – Street Lighting
  - C2545 – Pole Replacement
  - 41600 – Street Lighting

  These three activity codes incorporate all figures for streetlight installation, replacement and maintenance. This report also broke the project expenditure into cost elements.

- The cost elements were grouped using the mapping table in Appendix 3 to then generate the total public lighting figures for Direct Material Cost, Direct Labour Cost, Contract Cost and Other Cost.

- For the 2013/14 period the maintenance costs were split using the mapping table in appendix 6 and the Mincom Ellipse report sourced for template 4.1.2. The capital costs were split by cost category by running a project cost report from EPM for the list of projects reported. The expenditure figures were able to be broken up into the required cost categories; however the total costs in the project ledger do not match the regulatory account values. As such the percentages were used rather than the actual figures to ensure the total for connections expenditure balanced.

Metering

- The metering values in Regulatory Template 2.12 were calculated using the expenditure figures stated in RIN Table 4.2.2. For the full details of the calculation of each of these figures please refer to the Basis of Preparation for Regulatory Template 4.2.

- The expenditure figures for each year were classified into Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs based upon the logic detailed in Table 28.3 below:

Table 28.3: Information sources

Metering Expenditure Service Subcategory	Classification Methodology
Meter Purchase	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for meter

Metering Expenditure Service Subcategory	Classification Methodology
	purchases were 100% allocated to Direct Material Costs.
Meter Testing	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for meter testing were 100% Contractor Costs.
Meter Investigation	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for meter investigation were 100% Direct Labour Costs.
Scheduled Meter Reading	Scheduled meter reading in Energex is performed only by contractors and was classified as 100% Contractor Costs. All data in RIN Table 4.2.2 was derived from invoices paid to contractors.
Special Meter Reading	Special meter reading in Energex is performed only by contractors and was classified as 100% Contractor Costs. All data in RIN Table 4.2.2 was derived from invoices paid to contractors.
New Meter Installation	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for new meter installation were distributed between Direct Labour and Direct Materials Costs based on the workings for RIN Table 4.2.2.
Meter Replacement	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for meter replacements were distributed between Direct Labour, Direct Materials and Contractor Costs based on the workings for RIN Table 4.2.2.
Meter Maintenance	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for meter maintenance were distributed 100% to Direct Labour Costs based on these workings.
Other Metering	Figures in RIN Table 4.2.2 were calculated by using a build-up of materials, labour, contractor and other costs. The values for other metering were 100% allocated Direct Material Costs.

Each service subcategory figure per year for Direct Material Costs, Direct Labour Costs, Contract Costs and Other Costs was then summated to give the figures reported in the input tables Regulatory Template for each year.

Replacement

- Figures for replacement expenditure broken down into the required categories (Poles, Cables, and Transformers etc.) were calculated for Regulatory Template 2.2 – Repex in RIN Table 2.2.1. These figures were generated from project costs that were grouped into the required categories. For full details please refer to the Basis of Preparation for RIN Table 2.2.1.
- The costs for each classified project were able to be broken down into their respective cost elements. These were then used with the mapping table in Appendix 3 to generate Direct Material Cost, Direct Labour Cost, Contract Cost and Other Cost figures per project. The project level figures were then summated using the project classifications used in RIN Table 2.2.1 to produce the figures for the input tables Regulatory Template.

28.4 Estimated Information

Information reported for the following variables is estimated information:

- Overheads
- Routine Maintenance
- Non-routine Maintenance
- Vegetation Management
- Augmentation
- Connections
- Public Lighting
- Metering
- Replacement
- Fee-Based Services
- Quoted Services

28.4.1 Justification for Estimated Information

Overheads

- The requirement to apply the Classification of Services (CoS) and Energex's Cost Allocation Method (CAM) for the forthcoming regulatory control period to information reported throughout the RIN necessitated changes to all initially sourced data reported for overheads expenditure.

Fee-based and Quoted Services

- The requirement to apply changes in the CoS for the forthcoming period per the AER's framework and approach paper required retrospective changes to historical expenditure reported against these variables.

Connections, Routine and Non-Routine Maintenance, Augmentation, Vegetation Management, Public Lighting, Metering, and Replacement Expenditure

- Energex reporting of expenditure related to these variables is not directly aligned to the categories specified in the RIN. In order to comply with AER defined reporting requirements it was necessary to either:
  - Apply an apportionment method to originally sourced data; or
  - Map actual data or cost categories into AER defined categories.

Further information relating to the estimation of data reported for each of these variables can be found in the corresponding individual Basis of Preparations.

28.4.2 Basis for Estimated Information

For details of the Estimated Information please refer to the respective Basis of Preparation for each Regulatory Template.

28.5 Explanatory notes

Overheads

- Solar PV Feed-in Tariffs are subject to a jurisdictional scheme from 1 July 2015 and have therefore have been excluded from Template 2.10 – Overheads for back-casting purposes.
- Corporate Overheads for Corporate Restructuring began in 2012 as a result of Energex's conscious effort to reduce costs and employee numbers. This has resulted in the payment of termination benefits.
- The increase in Contractor Cost for Corporate Overheads over the five year period is the result of increasing IT and Communications costs.

Non-Network

- For detailed explanatory notes please refer to the bases of preparation 2.6.1, 2.6.2 and 2.6.3 (IT and Communication, Fleet and Equipment and Property respectively).

- Information in the RIN will differ from information provided in the CA RIN as Energex employee funded vehicles have been excluded from the calculation as these costs are fully funded by employees and not funded by customers. Also the km's travelled was adjusted to reflect the average rather than the total as populated in the CA RIN.

- In must be noted that there can sometimes be a small delay between when an invoice is paid and the asset is commissioned. If either of these circumstances span a financial year, a disconnect between financial transactions and physicals (when the asset is actually commissioned) occurs. This has occurred throughout the past five financial years, and is evident when there is expenditure and no physical in that year i.e.: 2012/13 Network Expenditure HCV – Elevated Work Platforms.

- Explanatory notes for negative balances seen in the Input table figures are as follows:
  - Routine Maintenance: DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE – Materials Costs 2010/11: The negative balance shown is due to the reversal of materials issued in prior years. The reversal of these materials resulted in a credit balance in the 2010/11 year.
  - Non-Routine Maintenance: POLE INSPECTION AND TREATMENT – Contract Costs 2012/13: The negative balance shown is due to the reversal of provisions relating to mitti cable inspection costs. These provisions were raised in a prior year and then deemed to be not required and subsequently reversed.
  - Non-Routine Maintenance: POLE INSPECTION AND TREATMENT – Other Costs 2012/13: The negative balance shown is due to the reversal of provisions relating to mitti cable advertising costs. These provisions were raised in a prior year and then deemed to be not required and subsequently reversed.
  - Replacement – Transformers – Other Costs 08/09 and 09/10: The negative balances in the replacement figures for transformers in 08/09 and 09/10 are due to returns of transformers. These transformers were expensed in prior years (pre 2008/09) and then returned in the reported years resulting in credit balances.

29 BoP 2.12.2 – Input tables – Related Party Costs

The AER requires Energex to provide the following information in Regulatory Template 2.12 - Input

Related party contractor costs, split by the following categories:

- **Vegetation Management**
- **Routine Maintenance**
- **Non-Routine Maintenance**
- **Overheads**
- **Augmentation**
- **Connections**
- **Emergency Response**
- **Public Lighting**
- **Metering**
- **Fee-based Services**
- **Quoted Services**
- **Replacement**
- **Non-Network Expenditure**

Actual Information was provided for all categories listed above for 2008/09 and 2011/12 to 2013/14.

Estimated Information was provided for 2009/10 and 2010/11.

This information forms part of Regulatory Template 2.12 Input tables.

29.1 Consistency with Reset RIN Requirements

Table 29.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 29.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Related Party In relation to Energex, any other entity that: • had, has or is expected to have control or significant influence over Energex; • was, is or is expected to be subject to control or significant influence from Energex; • was, is or is expected to be controlled by the same entity that controlled, controls or is expect to control Energex—	1) Energex has reported all relevant related party costs reported in the regulatory accounts in accordance with the categories specified in this Reset RIN table. The exception is for related party costs that had been assessed to be immaterial and weren't reported in the

<table>
<tr><th>Requirements (instructions and definitions)</th><th>Consistency with requirements</th></tr>
<tr><td>referred to as a situation in which entities are subject to common control;
• was, is or is expected to be controlled by the same entity that significantly influenced, influences or is expected to influence Energex; or
• was, is or is expected to be significantly influenced by the same entity that controlled, controls or is expected to control Energex;

but excludes any other entity that would otherwise be related solely due to normal dealings of:
• financial institutions;
• authorised trustee corporations as prescribed in Schedule 9 of the Corporations
• Regulations 2001 (Cth);
• fund managers;
• trade unions;
• statutory authorities;
• government departments;
• local governments and includes Energex Limited (ACN 078 849 055); or
• ·where any of the entities identified in sub-paragraphs (a) to (e) have novated or assigned a contract or arrangement to or from another entity (where that contract or arrangement relates to the provision of distribution services by Energex, the entity to whom that contract or arrangement has been novated or assigned.</td><td>annual regulatory accounts from 2013 in line with the AER annual RIN requirements. Prior to this, a materiality threshold did not apply and relevant Energy Impact Pty Ltd's costs were reported as related party costs. To enable comparison across the years, Energy Impact Pty Ltd's costs have been reported for all years in table 2.12.1.</td></tr>
<tr><td>Related party contract

A finalised Contract between Energex and a Related Party for the provision of goods and/or services.</td><td>Refer above.</td></tr>
<tr><td>Related party margin

The dollar amount of profit a Related Party gains above its total actual costs under a Related Party Contract with Energex. This profit may include margins, management fees or incentive payments.</td><td>SPARQ and Energy Impact transactions are at cost so there is no margin.</td></tr>
</table>

Actual Information was provided for all categories for 2008/09 and 2011/12 to 2013/14.

Estimated Information was provided for 2009/10 and 2010/11.

29.2 Sources

Related party cost information is either from the annual regulatory accounts or from transaction listings from Ellipse which support the amounts reported in the annual regulatory accounts.

Table 29.2 below sets out the sources from which Energex obtained the required information.

Table 29.2: Information sources

Category	Source
Network Overheads	Annual regulatory accounts and/or supporting workings
Corporate overheads	Annual regulatory accounts and/or supporting work papers for SPARQ Solutions Opex.
Non-Network Expenditure – IT & Communications	SPARQ Solutions Capex and Opex from the annual regulatory accounts.
Augmentation, Emergency Response, Replacement, Non-Network Expenditure – Buildings and Property	Annual regulatory accounts and/or supporting work papers.

29.3 Methodology

Energex sourced the relevant information from the annual regulatory accounts and/or supporting transaction listings and categorised the information as required in the AER Reset RIN Table based on the nature of the transactions.

29.3.1 Assumptions

- Consistent with the definition provided in the Reset RIN, Ergon Energy and Powerlink are also State-owned entities so have not been included as related parties.
- Information for 2008/09, 20011/12 to 2013/14 is based on the audited annual regulatory accounts and/or supporting work papers. No Estimated Information or assumptions were applied.
- For 2009/10 and 2010/11, assumptions were made and Estimated Information used in separating SPARQ Solutions costs into non-network IT&C expenditure and other categories.

29.3.2 Approach

- Energex categorised the relevant information from the regulatory accounts and/or supporting work papers as required in the Input Tables. Where applicable, detailed transaction listings supporting the regulatory accounts work papers were obtained. The transactions with related parties were categorised into the Reset RIN categories (emergency response, replacement, augmentation, etc.) based on their general ledger activity codes. Further classification into sub-categories for the relevant items was conducted by the Network Performance Manager based on the detailed descriptions of the purchase orders and/or invoices and/or work orders.
- Overhead costs are further sub-categorised into network overheads and corporate overheads based on the definitions used for Reset RIN Template 2.10 - Overheads.

29.4 Estimated Information

29.4.1 Justification for Estimated Information

- Based on the supporting work papers for the related party reporting in the annual regulatory accounts for 2010/11, SPARQ costs related to categories other than non-network IT&C (for example Emergency Response, Corporate Overheads and Network Overheads) were classified based on activity codes and responsibility centres.
- The 2009/10 SPARQ costs that were related to categories other than non-network IT&C were assumed to be incurred against categories in the same proportions as for 2010/11 non-network IT&C costs and have been classified accordingly.

29.5 Explanatory notes

Year	Reset RIN Table 2.12 related party cost total ('$000)	Related party cost total from the annual regulatory accounts ('$000)	Variance ('$000)	Explanations for the variance
2008/09	114,741	61,853	52,888	SPARQ Solutions opex is in both Corporate Overheads and Non Network Expenditure - IT&C in this table
2009/10	148,074	81,781	66,293	SPARQ Solutions opex is in both Corporate Overheads and Non Network Expenditure - IT&C in this table.

Year	Reset RIN Table 2.12 related party cost total ('$000)	Related party cost total from the annual regulatory accounts ('$000)	Variance ('$000)	Explanations for the variance
2010/11	172,948	446,367	(273,419)	- **$81,151k** SPARQ Solutions opex is included in both Corporate Overheads and Non-Network Expenditure - ITC in this table; - **($342,242k)** Powerlink TUOS is included in related party opex in the annual regulatory accounts but not included in this table for consistency and comparability with other years. - **($12,328k)** Ergon related party costs are included in the annual regulatory accounts but not included in this table as they don't meet the definition of related parties for the Reset RIN.
2011/12	203,188	114,410	88,778	- **$97,203k** SPARQ Solutions opex is in both Corporate Overheads and Non Network Expenditure - IT&C in this table. - **($8,425k)** Ergon related party costs are included in the annual regulatory accounts but not included in this table as they don't meet the definition of related parties for the Reset RIN.
2012/13	195,285	99,261	96,024	-**$2.5k** SPARQ Solutions costs are in both Emergency Response and Non Network Expenditure - IT&C in this table; - **$94,856k** SPARQ Solutions operating costs are both in Corporate Overheads and Non Network Expenditure - IT&C in this table;

Year	Reset RIN Table 2.12 related party cost total ('$000)	Related party cost total from the annual regulatory accounts ('$000)	Variance ('$000)	Explanations for the variance
				- **$1,166k** Energy Impact costs were not reported in the 2013 regulatory accounts as they didn't meet the materiality threshold as stated in the Annual RIN requirements, while in 2011 and 2012 all their costs were reported regardless of materiality in line with the Annual RIN requirements prior to 2013. They are therefore reported in this table for consistency.
2013/14	234,074	117,778	116,296	SPARQ operating costs that were in the general overhead pool are reported both in Corporate Overheads and Non Network Expenditure - ITC in this table;

30 BoP 2.13.1 – Provisions

As per the AER Reset RIN requirements, Energex has provided the following information relating to provisions for Standard Control Services (SCS):

Table 2.13.1 Changes in Total Provisions incl. RPM (Related Party Margin)

Movements for the following provisions are provided in this table:

- **Provision for Dividends**
- **Provision for Site Restoration – Toowoomba**
- **Provision for Site Restoration - Other**
- **Provision for Public Liability Insurance**
- **Provision for Employee Benefits**
- **Provision for Redundancy**
- **Provision for Overhead Service Line Inspections**
- **Provision for Environmental Offsets**
- **Provision for Home Suite**
- **Provision for Other**

Table 2.13.2 Allocation of Movement in Total Provisions incl. RPM

Allocation of movement, by provision, the total movements in provisions from Table 2.13.1 opex, as-incurred capex by asset class and other is provided in this table.

- **The following data is estimated:**
- **Provision for Site Restoration - Other**
- **Provision for Public Liability Insurance**
- **Provision for Employee Benefits**
- **Provision for Other**

In Table 2.13.2 Movements in provisions allocated to as-incurred capex by asset class are estimated as they are allocated based on the asset class' value over the total asset base of relevant years.

All other data is actual information.

This information forms part of Regulatory Template 2.13 Provisions.

30.1 Consistency with Reset RIN Requirements

Table 29.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 30.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In Table 2.13.1 provide, for each provision, the name and a brief description of the nature of the obligation in the spaces provided. Provision amounts must be inclusive of related party	Energex has reported, for all Regulatory Years, financial information on provisions for SCS. Up to 2013, provisions were reported in the

Requirements (instructions and definitions)	Consistency with requirements
margins (RPMs) if the DNSP incurs RPMs. Provision amounts must only relate to standard control services.	annual Regulatory Accounting Statements. From 2014, provisions were no longer required to be reported in the annual Regulatory Accounting Statements. However, the principles regarding provisions in previous years' Regulatory Accounting Statements apply to 2014 provisions. In line with the principles for the provisions reporting in the annual Regulatory Accounting Statements, provisions are allocated to services based on Property, Plant & Equipment (PP&E) balances. Provisions that are charged to indirect expenditure are apportioned to opex and capex components based on the relevant year's overhead allocation rate. Therefore the provision amount attributed to SCS is based on the proportion of the SCS PP&E to the total PP&E. The PP&E balances used for the allocation for the Reset RIN are based on the asset base as at 1 July 2015 per the AER requirements. For the Reset RIN, the apportionment of provisions that are charged to indirect expenditure to opex and capex components is based on the backcast overhead allocation ratio for the relevant year.
In Table 2.13.2 allocate, by provision, the total movements in provisions from Table 2.13.1 opex, as-incurred capex by asset class and other. 'Other' refers to movements in provisions that are recognised in equity, revenue, etc. rather than as an expense. The total 'movement' (the sum of the movements allocated to opex, capex and other) is equal to the difference between the carrying amount at the end of the period and the carrying amount at the beginning of the period in Table 2.13.1. The DNSP must insert their Roll Forward Model asset classes in the as-incurred capex section of Table 2.13.2.	Energex has allocated the total opex movement in provisions from Table 2.13.1 by provision, the total as-incurred capex movement by asset class and the total other movement by provision. Energex has inserted its Roll Forward Model asset classes in the as-incurred capex section of Table 2.13.2

30.2 Sources

- Up to 2013, reporting for all provisions is based on the annual Regulatory Accounting Statements and/or supporting workings.
- From 2014, provisions were no longer required to be reported in the annual Regulatory Accounting Statements.
- Therefore, reporting for all provisions for 2014 is based on the annual statutory financial statements and Regulatory Accounting Statements workings. The PP&E allocation rate is based on the calculated PP& balances as at 1 July 2015 in the 2015 Regulatory Proposal.
- The overhead allocation rates to opex and capex are based on backcast data for the Reset RIN.

30.3 Methodology

Methodology for the provisions reporting is detailed below.

30.3.1 Approach

- In line with the provisions reporting approach in the annual Regulatory Accounting Statements up to 2013 and the EB RIN (Economic Benchmarking Regulatory Information Notice) provisions reporting, provisions are allocated to services based on PP&E balances.
- Allocation of opening balances is based on the closing PP&E balances of the previous regulatory year. The current year movements and the closing balances are allocated based on the closing PP&E balances of the current regulatory year. Adjustments for the difference in allocation percentages between the current and prior regulatory years in the annual Regulatory Accounting Statements do not apply to the Reset RIN as the same PP&E allocation rate has been used for all years within the current regulatory determination period of 2010 to 2014. The PP&E allocation rate used for the Reset RIN has been calculated based on the asset base as at 1 July 2015 in the 2015 Regulatory Proposal.
- Provisions typically relate to opex, capex or indirect expenditure. When provisions are charged to indirect expenditure, they are allocated to opex and capex through the overhead allocation process. For the Reset RIN, provisions that are charged to indirect expenditure are apportioned to opex and capex components based on the backcast overhead allocation ratio for the relevant year. For that reason, those provisions that are charged to indirect expenditure are considered to be estimated information.
- Table 30.2: Explanatory Notes on Provisions, over page, provides background on each of the provisions:

Table 30.2: Explanatory Notes on Provisions

Provision Name	Capex and Opex Components
Provision for dividends	Neither Opex nor Capex. It is related to Net Operating Profit After Tax and charged directly to Retained Earnings. Its movements are reported in the Reset RIN under Other Component.
Provision for Site Restoration - Toowoomba	Charged to Other as it represents unregulated expenditure for a former gas site.
Provision for Site Restoration - Other	Charged to indirect expenditure and allocated to opex and capex through overhead allocations.
Provision for Public Liability Insurance	Charged to indirect expenditure and allocated to opex and capex through overhead allocations.
Provision for Employee Benefits	Charged to indirect expenditure and allocated to opex and capex through overhead allocations. The "increase during the period in the discounted amount arising from the passage of time and the effect of any change in the discount rate" is not specifically disclosed in the statutory financial statements. For the Reset RIN reporting purposes, this variable is based on inflation and discounting of the leave entitlements per the workings supporting employee benefits balances in the statutory financial statements, multiplied by the PP&E allocation rate and the opex/capex overhead allocation rate. The amount for leave entitlements is the accrued leave balance per payroll records plus on-costs such as payroll tax, superannuation and workers' compensation.
Provision for Redundancy	Charged to other support cost directly, therefore 100% allocated to opex.
Provision for Overhead Service Line Inspections	Charged to inspection costs directly, therefore 100% allocated to opex.
Provision for Environmental Offsets	Charged to opex and capex directly based on relevant components, not through overhead allocations.
Provision for Home Suite	Charged to other support cost directly, therefore 100% allocated to opex. Provision for Home Suite has been included in Provision for Other from 2011 in line with the annual Regulatory Accounting Statements.

Provision Name	Capex and Opex Components
Provision for Other	Charged to indirect expenditure and allocated to opex and capex through overhead allocations.

- Energex does not have related party margin.

Table 2.13.2 Allocation of Movement in Total Provisions incl. RPM

- The opex components of each provision's movements, including addition, utilisation, reversal and the increase during the period in the discounted amount arising from the passage of time and the effect of any change in the discount rate, are added for each provision and provided in this table. The same approach has been applied to the other components of each provision's movements.

- The capex components of all provision's movements, including addition, utilisation, reversal and the increase during the period in the discounted amount arising from the passage of time and the effect of any change in the discount rate, are added and allocated to each asset class based on the percentage of each asset class' value over the total asset base from the asset Roll Forward Model (RFM\) provided by the AER for the 2010 regulatory determination, updated with actual capex, disposal and CPI rate for each of 2011 to 2014 years, which has been used in reporting the regulated asset base values for the EB RIN.

30.4 Estimated Information

- Within provisions, some amounts were estimated in their apportionment between Opex and Capex.

- Movements in provisions allocated to as-incurred capex by asset class are estimated.

- All other amounts are actual information.

30.4.1 Justification for estimates

- The apportionment for provisions charged to indirect expenditure is based on the overhead allocation to opex and capex therefore it is estimated.

- The apportionment of capex movements of provisions is allocated based on each asset class' value therefore estimated.

30.4.2 Basis for estimates

- The overhead allocation rate for each service (SCS, ACS – Alternative Control Service and Non-regulated Services) is calculated as the percentage of the allocation amount to a specific service (identified through activity codes for each service) over the total allocation (identified through the overhead allocation element).

- The apportionment of capex movements of provisions is allocated based on each asset class' value over the total asset base for each year from the asset Roll Forward Model.

30.5 Explanatory notes

The closing balances of provisions for 2010 are not the same as the opening balances of provisions for 2011 for the following reasons:

1) For 2006 to 2010, Provision for Dividends was specifically excluded from regulatory reporting requirements (refer Para 6.11 of QCA Electricity Distribution: Regulatory Accounting and Information Guidelines Sept 2004). From 2011 it was reported in the annual Regulatory Accounting Statements.

2) Provision for Defined Benefit Superannuation Fund Deficit was included in provisions in the annual Regulatory Accounting Statements up to 2010. It has been excluded from 2011 as it is a separate liability in the statutory accounts and is not regarded as a provision.

3) Provision for Home Suite was combined with Provision for Other from 2011.

4) Prior to 2011, services were classified as DUOS and Non-DUOS or as DUOS and Excluded Distribution Services, the combination of which were considered to be DNSP services. Reporting in the Reset RIN represents provisions for the DNSP as per the annual Regulatory Accounting Statements. From 2011, services are classified as SCS, ACS and Non-Regulated. Reporting in the Reset RIN represents provisions for SCS only and does not include the portion attributable to ACS per the Reset RIN requirements.

However, the Reset RIN templates stipulate that the opening balance of each year equal the closing balance of the previous year for each provision. Therefore, for those provisions that have differences between the opening balance of one year and the closing balance of the previous year for certain years due to the reasons detailed above, the following adjustments have been made in the templates purely for the purpose of balancing the opening balance of one year to the closing balance of the previous years:

1) Provision for Dividends – The opening balance of 2011 has been treated as Additional provisions made in the period, including increases to existing provisions in 2010, allocated to other component in line with the treatment of this provision's movement in other years.

2) Provision for Site restoration – other – The opening balance of 2011 has been treated as Additional provisions made in the period, including increases to existing provisions in 2010, allocated to opex and capex components in line with the

treatment of this provision’s movement in other years, based on 2010’s overhead allocation ratio.

3) Provision for Public Liability Insurance - The decrease in opening balance of 2011 from the 2010 closing balance has been treated as Unused amounts reversed during the period in 2010, allocated to opex and capex components in line with the treatment of this provision’s movement in other years, based on 2010’s overhead allocation ratio.

4) Provision for Employee Benefits - The decrease in opening balance of 2011 from the 2010 closing balance has been treated as Unused amounts reversed during the period in 2010, allocated to opex and capex components in line with the treatment of this provision’s movement in other years, based on 2010’s overhead allocation ratio.

5) Provision for Home Suite – The closing balance of 2010 has been treated as Amounts used in 2011 as other component.

6) Provision for Other - The decrease in opening balance of 2011 from the 2010 closing balance has been treated as Unused amounts reversed during the period in 2010, allocated to opex and capex components in line with the treatment of this provision’s movement in other years, based on 2010’s overhead allocation ratio.

Detailed explanations in relation to provisions movements are provided in Appendix 6 – Provisions Movements.

31 BoP 2.14.1 – Forecast Price Changes

The AER requires Energex to provide the following information relating to Table 2.14.1 – Forecast labour and materials price changes:

Historical and Forecast price changes for the period 2010/11 to 2019/20 relating to:

- **Material price changes**
- **Labour price changes**
- **“Other” price changes**
- **Changes in CPI (split by OPEX and CAPEX if different escalators were utilised)**

Price changes are to be recorded in percentage year on year real terms.

Estimated information was provided for price changes for the following:

- **Commodity prices such as aluminium, copper, steel oil**
- **Inflation**
- **Employee and contractor labour costs**
- **Program of Work asset prices**
- **General materials, non-system buildings, motor vehicles, occupancy expenditure, transport costs**
- **Land and land tax**
- **Historical and forecast CPI**

These variables are part of Regulatory Template 2.14 – Forecast Price Changes.

31.1 Consistency with Reset RIN Requirements

Table 29.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 31.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must provide labour and material price changes assumed by Energex in estimating Energex's forecast capex proposal and forecast opex proposal. All price changes must be expressed in percentage year on year real terms.	Energex has reported in template 2.14 of the Reset RIN the historical labour, contractor and material price changes (cost escalation rates) for the period 2010/11 to 2013/14. Energex has also reported the forecast labour, contractor and material cost escalation rates used to estimate its forecast capex proposal and forecast

	opex proposal. All cost escalation rates are presented in real terms. Inflation rates are reported separately for the period 2010/11 to 2019/20
In Energex's Basis of preparation document(s), provide a written explanation of: • The methodology underlying the calculation of each price change, including: – Sources – Data conversions – The operation of any model(s) – The use of any assumptions • Whether the same price changes have been used in developing both the forecast capex proposal and forecast opex proposal.	Energex has detailed in the Basis of Preparation the methodology underpinning the calculation of each price changes. Energex confirms that it has used the same price changes for determining its forecast capex proposal and forecast opex proposal. The methodology and approach used to derive the historical and forecast cost escalators may vary.

No actual information was provided for the determination of the historical price changes and forecast cost escalation rates. All information provided in RIN template 1.14 required a degree of judgement.

Estimated information was provided for:

- Historical and forecast employee and contractor labour costs
- Historical and forecast commodity prices - aluminium, copper, steel, oil, wood poles
- Historical and forecast Program of Work assets - overhead sub-transmission lines, underground sub-transmission cables, overhead distribution lines, underground distribution cables, distribution equipment, substation bays, substation establishment, distribution substation switchgear, zone transformers, distribution transformers, low voltage services, metering, communications – pilot wires, street lighting, control centre – SCADA, system buildings
- Historical and forecast general materials expenditure, non-system buildings expenditure, motor vehicle costs, occupancy expenditure, transport costs
- Historical and forecast land value and land tax costs.

31.2 Sources

Table 31.2 below sets out the sources from which Energex obtained the required information.

Table 31.2: Information sources

Category	Source
Historical and forecast aluminium, copper, steel and oil prices	London Metal Exchange; Consensus Economics; MEPS, Bloomberg; US-Energy Information Administration; NYMEX. For further details refer to Jacobs SKM report – Material Cost Escalation Factors, Support for 2015/20 Regulatory Submission for Energex Ltd, August 2014
Historical and forecast construction cost index	Australian Construction Industry Forum. For further details refer to Jacobs SKM report – Material Cost Escalation Factors, Support for 2015/20 Regulatory Submission for Energex Ltd, August 2014
Historical Australian CPI	Australian Bureau of Statistics
Forecast Australian CPI	Statement on Monetary Policy published by the Reserve Bank of Australia
Historical and forecast Program of Work material costs (overhead sub-transmission lines, underground sub-transmission cables, overhead distribution lines, underground distribution cables, distribution equipment, substation bays, substation establishment, distribution substation switchgear, zone transformers, distribution transformers, low voltage services, metering, communications – pilot wires, street lighting, control centre – SCADA, system buildings)	Jacobs SKM report – Material Cost Escalation Factors, Support for 2015/20 Regulatory Submission for Energex Ltd, August 2014
Historical land and land tax value	Land tax assessment notices
Forecast land and land tax value	ABS, Australian System of National Accounts, 2012-13, ABS Cat No. 5204.0 Table 61. For further details refer to PWC report – Forecast Cost Escalation Rates Final Report, 4 March

Category	Source
	2014
Historical employee costs	Energex’s 2009 and 2011 EBA; non-executive contracts; individual employment agreements; executive contracts; senior executive contracts
Forecast employee costs	Wage Price Index (published by Commonwealth Treasury). For further details refer to PWC report – Forecast Cost Escalation Rates Final Report, 4 March 2014
Historical contractor labour costs	Contract costs extracted from Ellipse - Energex’s general ledger
Forecast contractor labour costs	Wage Price Index (published by Commonwealth Treasury); forecast CPI based on the RBA’s Statement on Monetary Policy. For further details refer to PWC report – Forecast Cost Escalation Rates Final Report, 4 March 2014
Historical general materials costs	CPI - All Groups (Australia) published by the ABS
Forecast general materials costs	Forecast CPI based on the RBA’s Statement on Monetary Policy. For further details refer to PWC report – Forecast Cost Escalation Rates Final Report, 4 March 2014
Historical and forecast non-system building (capital expenditure) costs	Australian Construction Industry Forum (Construction Forecasting Council). For further details refer to PWC report – Forecast Cost Escalation Rates Final Report, 4 March 2014
Historical occupancy expenditure	Land and building costs, rent and leases, rates, utility charges extracted from Ellipse – Energex’s general ledger

Category	Source
Forecast occupancy expenditure	Escalation clauses in Energex's metropolitan property leases
Historical transport costs	Fuel costs, scheduled and unscheduled maintenance, vehicle registration, and accident and damage costs were extracted from Ellipse - Energex's general ledger
Forecast transport costs	Forecast CPI based on the RBA's Statement on Monetary Policy; CPI-Insurance (Australia); Queensland WPI in Queensland Treasury and Trade's 2013/14 Economic Performance and Outlook budget paper; Queensland Government's indexation policy (GIP). For further details refer to PWC report – Forecast Cost Escalation Rates Final Report, 4 March 2014
Historical motor vehicle costs	CPI-All Groups (Australia) published by the ABS
Forecast motor vehicle costs	CPI based on the RBA's Statement on Monetary Policy. For further details refer to PWC report – Forecast Cost Escalation Rates Final Report, 4 March 2014

31.3 Methodology

Various methodologies were applied in deriving Energex's cost escalation rates.

1) Historical and forecast commodities and Program of Work material cost escalation rates were developed by Jacobs SKM using their well-established and tested model.

2) Energex also engaged PWC to develop forecast cost escalation rates for labour, contractors, occupancy expenditure, transport costs, motor vehicle costs and ancillary material expenditure. In deriving historical price change rates from 2010/11 to 2013/14 for these cost items, Energex used historical information from Ellipse (Energex's general ledger) when readily available and meaningful. If not readily available or meaningful, Energex used relevant cost indices to estimate the historical price estimations.

31.3.1 Assumptions

A number of assumptions were applied to historical contractor prices and historical land values.

1) In deriving historical contractor price changes for the period 2010/11 to 2013/14, Energex applied the following assumptions to the required information:
    a. Given that approximately 80% of System based spend is capped at 3 per cent, a 3 per cent annual escalation was applied across all periods.
    b. For Non system contracts, Energex was not able to determine the actual price escalation factor for this category. Instead, various methodologies were used to derive the annual price escalations. Examples of these methodologies include annual CPI increases, annual WPI increases, fixed percentage increases, fixed price and lump sum quotations. An assumption was made that CPI or current AER escalation allowance would normally be applied for annual price escalation and this has been used as the basis for the actual price escalation.
2) In deriving Energex's land values for the period 2010/11 to 2013/14, Energex used the annual Assessment Notices sent by the Queensland Government.

31.3.2 Approach

Approach used to determine forecast cost escalation rates

1) The methodology (including the sources, data conversion, models and assumptions) used to derive the forecast cost escalation rates is detailed in reports prepared by external consultants Jacobs SKM and Price Waterhouse Coopers (PWC)17. These documents are provided as appendices in Energex's 2015-20 Regulatory Proposal.
2) The forecast CPI values for the period 2014/15 to 2019/20 were derived using the Statement on Monetary Policy published by the Reserve Bank of Australia (RBA) dated 7 August 2014. The mid-point of 2.5 per cent of the RBA inflation target (2 to 3 per cent) was considered appropriate.

Approach used to determine historical cost escalation rates

Historical employee price changes:

1) The employee category includes:
    a. Staff covered by the Enterprise Bargaining Agreement (EBA); and
    b. Staff not covered by the EBA such as non-executive contracts, individual employment agreements, executive contracts and senior executive contracts.

[17] The values in the PWC report were updated in an Addendum to the report on 11 August 2014

Energex applied the following approach to obtain the required information:

2) To determine labour costs for staff covered by the EBA, Energex used the rate increases as defined in the 2008 and 2011 EBAs.

3) To determine labour costs for staff not covered by the EBA, Energex used the rate increases signed off by Energex's Board for each of these various groups.

4) A weighted average was applied to those labour rates. The weights were based on the number of employees in each contract or agreement category for each year.

Historical contractor labour price changes:

1) The contractor labour category includes:
    a. System based contractors (non-professional services); and
    b. Non-system based contractors (professional and support services).

Energex applied the following approach to obtain the required information:

1) Extract spend from Ellipse (Energex's general ledger) by contract and group all contracts (excluding material contracts) in System based and Non-system based categories for 2010/11, 2011/12, 2012/13 and 2013/14.

2) Calculate the split between System based and Non-system based, and use this in the weighted price escalation calculation.

3) Determine System based percentage escalation – for approximately 80 per cent of spend, the annual increase for System based contracts have been capped at a maximum of 3 per cent. Therefore a 3 per cent annual escalation was applied across all periods.

4) Non system percentage escalation - Actual CPI was used as the escalation rate for across all periods.

5) Determine the annual price escalations per category.

6) Calculate the weighted average price escalation.

Historical commodities price changes:

Please refer to Jacobs SKM report – Material Cost Escalation Factors, Support for 2015/20 Regulatory Submission for Energex Ltd, August 2014.

Historical Program of Work materials price changes:

Please refer to Jacobs SKM report – Material Cost Escalation Factors, Support for 2015/20 Regulatory Submission for Energex Ltd, August 2014.

Historical general materials price changes:

1) The general materials asset category includes:
    a. Non-Program of Work store-issued materials - items used in operating activities booked out of inventory;
    b. Direct purchases - items used in operating activities not stocked in inventory;
    c. Work wear – clothing; and
    d. Office consumables.

2) Because of the large number and heterogeneous nature of the goods in this asset category, the use of Energex's historical data was not considered practical for determining the annual price variations for the period 2010/11 to 2013/14.

3) Instead, Energex has used CPI-All Groups (Australia) to reflect the year on year change in price for general materials. This is consistent with PWC's approach in forecasting general materials (refer to PWC's report for further details).

Historical non-system building (capital expenditure) price changes:

1) Non-system building capital expenditure includes purchases associated with the construction of office buildings and redevelopment of field offices and depots.

2) To derive historical annual price changes in non-system building expenditure for the period 2010/11 to 2013/14, Energex used the Australian Construction Price Index published by the Australian Construction Industry Forum (Construction Forecasting Council). This is consistent with PWC's approach in forecasting non-system building expenditure cost escalation rates (refer to PWC's report for further details).

Historical land and land tax price changes:

1) Historical land tax values and land tax cost variations for the period 2010/11 to 2013/14 were based on the land values included in the annual Land Tax Assessment Notices sent annually by the Queensland Government's Office State Revenue.

2) Historical land values and land tax price changes were derived using the annual percentage change in Energex's estimated land value as per the annual Land Tax Assessment Notices.

Historical occupancy price changes:

1) Occupancy expenditure category includes:
    a. Rent and leases
    b. Utilities (water, gas and electricity)
    c. Rates
    d. Land and building maintenance.

2) In determining Energex's historical occupancy price changes Energex used the actual annual expenditure for the period 2010/11 to 2013/14, extracted from Ellipse for the following items:

    a. Rent & leases (lands and buildings)
    b. Electricity & gas
    c. Rates
    d. Land & Buildings – Repairs and maintenance, cleaning, security and waste

Specific weights based on the contribution of each cost items towards the total annual occupancy expenditure were applied.

Historical transport price changes:

1) Transport expenditure category includes:

    a. Vehicle maintenance
    b. Fuel and oils
    c. Vehicle registration
    d. Insurance costs.

2) In determining Energex's historical transport price changes for the period 2010/11 to 2013/14, Energex used the actual annual expenditure extracted from Ellipse and applied specific weights to each cost item based on its contribution towards the total transport expenditure in each year.

Historical motor vehicle price changes:

1) Energex's motor vehicle fleet includes light, medium and heavy vehicles.

2) Energex only applied CPI to derive its historical motor vehicle price variations between 2010-11 and 2013-14.

31.4 Estimated Information

Energex has used indices to derive the annual rate of change of expenditure which could not be readily extracted from Energex's information systems or presented yearly variations of such a scale that were not considered meaningful.

31.4.1 Justification for Estimated Information

Indices were used to determine historical price variations for the following reasons:

- General material - Heterogeneous nature of the goods purchased
- Motor vehicle – Heterogeneous nature of the motor vehicle purchased

- Non-system buildings expenditure – Significant annual variations relating to specific business requirements over the 2010/11 to 2013/14 period
- Land and land tax – Significant variations relating to specific business requirements over time over the 2010/11 to 2013/14 period

The nature of the aforementioned expenditure categories makes it difficult to derive meaningful historical trends.

31.4.2 Basis for Estimated Information

- To estimate cost escalation rates for general materials costs and motor vehicle expenditure for the period 2010/11 to 2013/14, Energex used CPI - All Groups (Australia).
- To derive historical annual price changes in non-system building expenditure for the period 2010/11 to 2013/14, Energex used the Australian Construction Price Index published by the Australian Construction Industry Forum (Construction Forecasting Council).
- Historical land values and land tax costs for the period 2010/11 to 2013/14 were based on the land values included in the annual Land Tax Assessment Notices sent annually by the Queensland Government's Office State Revenue.

31.4.3 Explanatory notes

The QLD Reset RIN 2015-20 estimated templates sheet 2.14 Forecast Price Changes does not have the data in percentages. Energex is unable to change the format to show percentages.

32 BoP 2.15.1 – Commercial Insurance and Self-Insurance

The AER requires Energex to provide the following information relating to Table 2.15.1 – Forecast Commercial insurance premiums by Risk Category:

Information for 2013/14 relating to premiums as follows

- **Risk Class**
- **Risk Category**
- **Deductibles**
- **Policy limits**
- **Premiums**

Actual information was provided for 2013-14 variables, whilst estimated information was provided for forecast variables.

The AER requires Energex to provide the following information relating to Table 2.15.2 - Insurance premium - Total property:

Historical information for the period 2010/11 to 2013/14 relating to Total Property Premiums per the following categories and subcategories:

- **Base Premiums**
  - **Value of insured assets**
  - **Premium (exposure x unit rate)**
- **Statutory charges**
  - **Stamp Duty ($ nominal)**
  - **Any additional items (Energex to nominate)**
- **Total Premiums (exc. GST)**

Actual information was provided for historical and current (2013-14) Policy limits, Premiums, Deductibles.

The AER requires Energex to provide the following information relating to Table 2.15.3 - Insurance premium - Total liability:

Historical information for the period 2010/11 to 2013/14 relating to Total Liability Premiums per the following categories and subcategories:

- **Base Premium**
  - **Liability Cap**
  - **Premium**
- **Statutory charges**
  - **Stamp Duty**
  - **Any additional items (Energex to nominate)**
- **Total Premiums (exc. GST)**

Actual information was provided for historical and current (2013-14) Policy limits, Premiums, Deductibles.

These variables are part of Regulatory Template 2.15 – Insurance and Self Insurance

32.1 Consistency with Reset RIN Requirements

Table 32.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 32.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Regulatory template 2.15.1 must provide a summary of all Energex's proposed insurance costs.	Table 2.15.1 provides a summary in accordance with this requirement.
Regulatory template 2.15.2 and 2.15.3 seek more detailed information regarding total property and liability premiums only.	More detailed information has been provided in tables 2.15.2 and 2.15.3
Amounts are exclusive of GST	All amounts included in regulatory template 2.15 are exclusive of GST

Actual information was provided for all historical and current (2013-14) Policy limits, Premiums, Deductibles.

32.2 Sources

Sources of information include:

- Historical insurance renewal report – provided annually by Willis, detailing premiums and stamp duty by insurance class.
- Historical insurance premium invoices – detailing total annual premiums paid by insurance class.
- Historical Energex Property Schedules – submitted annually by Energex to Insurance broker Willis, as part of the policy renewal process. Used to determine value of property requiring insurance, on which premiums and coverage is based.
- Existing Energex Insurance Policy Wordings – detailing terms and conditions in each insurance class including deductibles, policy limits, and other conditions such as confidentiality clauses.
- Insurance Premium Overview – summary of all insurance classes currently in place, premiums, limits and deductibles
- Insurance broker advice – regarding confidentiality requirements of insurance policies
- Self-Insurance Provision Actuarial study 2014 – report prepared by Willis forecasting self-insurance costs for regulatory period.

Table 32.2 below sets out the sources from which Energex obtained the required information.

Table 32.2: Information sources

Category	Source
Deductibles	4
Policy Limit	4
Premium - current	4, 5
Premium - forecast	5, 6
Stamp Duty	1
Liability Cap	1, 5
Self- Insurance proposed allowance	7
Value of Insured Assets - Property	3

32.3 Methodology

32.3.1 Assumptions

Energex did not apply any assumptions when obtaining the required information.

32.3.2 Approach

Energex applied the following approach to obtain the required information:

- Stamp Duty and GST applies to certain elements of Coverage and is dictated by Legislative considerations in the domicile of the insurer.
- Value of Premiums - includes any nominal administration fees charged by the Insurance broker, and exclude applicable G.S.T., Stamp Duty, and Fire Services Levy.
- Value of Insured Assets for 2010/11 – 2013/14 based on actual figures as represented in the Energex Property Schedule.

- Value of Liability Cap 2010/11 – 2013/14 is based on the total of actual insured limits in liability policies, taken from each insurance Policy.
- All Historical figures are based on actual policy information, provided annually in the insurance policy wording and the Willis Insurance Renewal Reports.
- Property values were based actual portfolios for the years reported, as represented in the Energex Property Schedule.
- Given the fact that data has been collected and captured in the annual Insurance renewal process and reported formally from Willis in the Insurance Renewal Reports, there was no requirement for additional calculations or data sources.

32.4 Estimated Information

No estimates were reported with respect to information provided for the 2010/11 to 2013/14 regulatory years.

33 BoP 2.17.1 – Step Changes

The AER requires Energex to provide information relating to step changes in forecast expenditure, however the Reset RIN templates require historical step changes back to 2008-09.

As historical information needs to be covered by a Basis of Preparation (BoP), this BoP addresses historical information in template 2.17 Step Changes.

Reset RIN template 2.17 requires:

- **Table 2.17.1 – forecast opex step changes for Standard Control Services**
- **Table 2.17.2 – forecast capex step changes for Standard Control Services**
- **Table 2.17.3 – forecast opex step changes for dual function assets**
- **Table 2.17.4 – forecast capex step changes for dual function assets**

All historical information for step changes is considered to be actual information.

These variables are part of Regulatory Template 2.17 – Step Changes

33.1 Consistency with Reset RIN Requirements

Table 33.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 33.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Schedule 1 section 4 of the Reset RIN requires step changes in forecast expenditure	Energex has provided forecast step changes where applicable
Appendix E section 3.1 of the Reset RIN states that Energex must explain, for all historical information in the *regulatory templates* (up to and including 2013-14 and including *Actual Information* and *Estimated Information*) and forecast information where this has been explicitly stated in this Notice, the basis upon which Energex prepared information to populate the input cells (*basis of preparation*)	This BoP details step changes from 2008-09 to 2013-14

All historical information for step changes is considered to be actual information.

33.2 Sources

Table 33.2 over page sets out the sources from which Energex obtained the required information.

Table 33.2: Information sources

Category	Source
Forecast opex step changes for Standard Control Services	Consistent with historical regulatory accounting statements
Forecast capex step changes for Standard Control Services	Consistent with historical regulatory accounting statements, this information has never been reported
Forecast opex step changes for dual function assets	Not applicable to Energex, who does not have dual function assets
Forecast capex step changes for dual function assets	Not applicable to Energex, who does not have dual function assets

33.3 Methodology

Energex has populated the historical information consistent with its historical regulatory accounting statements.

33.3.1 Assumptions

Energex has assumed that historical information for:

- opex step changes are not relevant as Energex has not been previously subject to a Base-Step-Trend forecasting approach.
- capex step changes are not relevant as capex is considered non-routine in nature and therefore not subject to a Base-Step-Trend forecasting approach.

33.3.2 Approach

- As stated above, Energex has not reported any step changes as Energex has not been previously subject to a Base-Step-Trend forecasting approach for operating expenditure. Further, Energex considers that capex is non-routine in nature and therefore not subject to a Base-Step-Trend forecasting approach.

33.4 Estimated Information

No information is considered to be estimated.

34 BoP 3.2 – Opex

The AER requires Energex to provide the following information relating to Table 3.2.1.1 Current opex categories and cost allocations:

- **Backcast information for Standard Control Services (SCS) and Alternative Control Services (ACS) by individual opex category, being:**
  - **Inspection**
  - **Planned maintenance**
  - **Corrective repair**
  - **Vegetation**
  - **Emergency response / storms**
  - **Other network maintenance costs**
  - **Network operating costs**
  - **Meter reading and network billing**
  - **Customer services (inc call centre)**
  - **DSM initiatives**
  - **Levies**
  - **Debt raising costs**
  - **Other operating costs (inc self insurance)**

The AER requires Energex to provide the following information relating to Table 3.2.2.1 Opex consistency - current cost allocation approach:

- **Opex for network services**
- **Opex for metering**
- **Opex for connection services**
- **Opex for public lighting**
- **Opex for amounts payable for easement levy or similar direct charges on DNSP**
- **Opex for transmission connection point planning**

Estimated information was provided for all variables.

These variables are a part of Regulatory Template 3.2 – Opex.

34.1 Consistency with Reset RIN Requirements

Table 34.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 34.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Appendix E section 16.1 states that Energex must: Complete the Economic Benchmarking regulatory	Energex has completed Template 3.2 as required

templates (3.1 to 3.7) in accordance with: a) The instructions and definitions for variables within: Economic benchmarking RIN For distribution network service providers Instructions and Definitions Energex (ABN 40 078 849 055) November 2013; and b) The instructions in paragraphs 16.1 to 16.10; however, c) If there is inconsistency between the instructions in paragraphs 16.1 to 1.10 and those in the instructions and definitions for variables within: Economic benchmarking RIN for distribution network service providers Instructions and Definitions Energex (ABN 40 078 849 055) November 2013 the instructions in paragraphs 16.2 to 16.9 take precedence.	
Appendix E section 16.3 states that: d) Information provided in regulatory templates 3.2.1 and 3.2.2 must reflect Energex's Cost Allocation Method to take effect on 1 July 2015.	Energex has backcast the opex information in accordance with its Cost Allocation Method (CAM) effective from 1 July 2015

Estimated information was provided for all variables.

34.2 Sources

Table 29.2 below sets out the sources from which Energex obtained the required information.

Table 34.2: Information sources

Category	Source
DOPEX0101 – DOPEX0113 Opex categories	• Backcasting for Economic Benchmarking (EB) RIN initial years (2005-06 to 2012-13) • 2014 EB RIN • Regulatory accounting workpapers

Category	Source
	• Classification of Services (CoS) from AER's final Framework & Approach • CAM changes based on Energex's AER-approved CAM effective 1 July 2015 • Meter maintenance forecasts used for the regulatory proposal • Australian Bureau of Statistics (ABS) Consumer Price Index (CPI) rates for weighted average of eight capital cities • Reset RIN overheads backcasting (refer separate BoP)
DOPEX0201 – DOPEX0107 Opex consistency categories	• Table 3.2.1.1 Opex Categories • Regulatory accounting workpapers

34.3 Methodology

Opex numbers have been backcast using the new CoS and CAM applicable from 1 July 2015. These numbers are inclusive of overheads consistent with the EB RIN and advice from the AER for the Reset RIN.

34.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Numbers for CoS changes for the first three years (2005-06 to 2007-08) are assumed to be the same as for 2008-09 and have been de-escalated using the ABS CPI for weighted average of eight capital cities.
- For the last six years (2008-09 to 2013-14), the overhead pool related to opex has been determined based on backcasting for template 2.10 Overheads. For the first three years, the overhead pool related to opex has been determined by de-escalating the 2008-09 overhead pool related to opex.
- Opex proportions for the last six years have been determined based on backcasting for template 2.10 Overheads. Opex proportions for the first three years have assumed to be the same as 2008-09.
- Overheads for CoS changes have been applied at the rate of total overheads to total direct costs
- Overheads for variables not subject to CoS changes have been applied at the rate applicable prior to backcasting and include changes in the size of the overhead pool
- Allocation of Other Operating Costs (DOPEX0113) between SCS and ACS is based on the allocation rates for the next Determination period

- The unregulated three-factor rate for the first five years was based on EB RIN backcasting as the rates have only applied from 2010-11

34.3.2 Approach

Table 3.2.1.1 Current opex categories and cost allocations

Energex applied the following approach to obtain the required information for Table 3.2.1.1 Current opex categories and cost allocations (DOPEX0101 – DOPEX0113):

1) Energex first compiled the EB RIN backcasting information for years 2005-06 to 2012-13 and the current year (2013-14), disaggregated by direct and overhead costs.

2) Next, direct costs for CoS changes identified for Reset RIN backcasting (back to 2008-09) were de-escalated to 2005-06 using the ABS CPI rates for weighted average of eight capital cities.

3) Overheads were then applied to these CoS changes using the general overhead rate applicable for all direct costs for the relevant year.

4) These services were classified as:
    a. Additions to ACS opex – for pre-connection services, connection services (real estate developments/sub-divisions), rearrangement of shared network assets, upgrade from single to 3 phase, accreditation of alternative service providers, and metering costs.
    b. Subtractions from ACS opex – for emergency recoverable works for known damage.
    c. Subtractions from SCS opex – for Solar PV FiT payments and metering costs.

5) Other Operating Costs (DOPEX0113) were allocated to SCS, ACS and unregulated services after CoS changes.

6) Backcast overheads applicable to each variable were determined based on the following:
    a. For services unaffected by CoS changes – proportions of the overhead pool related to opex, applied to the post-backcast overhead pool for opex
    b. For services affected by CoS changes – the proportion of general overhead to direct costs

7) Aggregation of the direct costs and overheads for each variable

Table 3.2.2.1 Opex consistency - current cost allocation approach

Energex applied the following approach to obtain the required information for Table 3.2.2.1 Opex Consistency – current cost allocation approach (DOPEX0201 – DOPEX0207):

1) Calculated opex for metering (DOPEX0202) by:

   a. Starting with the costs from Meter reading and network billing (DOPEX0108) which, for Energex, represents meter reading, network billing and other market support services

   b. Deducting costs associated with network billing and other market support services

2) Populated opex for connection services (DOPEX0203) as the reclassified service for real estate developments/sub-divisions

3) Populated opex for public lighting (DOPEX0204) as Other network maintenance costs (DOPEX0106), which represents Energex's maintenance costs for public lighting

4) Calculated opex for network services (DOPEX0201) as Total Opex (DOPEX0101) less opex for metering (DOPEX0202) less opex for connection services (DOPEX0203) less opex for public lighting (DOPEX0204)

   Note: Opex for network services (DOPEX0201) for ACS is not required to be populated in the EB RIN and has not been populated in the Reset RIN.

34.4 Estimated Information

All backcast information is considered to be estimated.

34.4.1 Justification for Estimated Information

Estimated information is defined in the Reset RIN as:

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

Accordingly, backcast information for CoS and CAM changes must meet this definition as it is:

- not materially dependent on information in Energex's historical accounting records;
- inherently based on judgements and assumptions for which there could be valid alternatives.

In addition, sections 3.6 and 3.7 of Appendix C: Audit and Review to the Reset RIN indicate that backcast information is subject to review consistent with that required for estimated information.

34.4.2 Basis for estimates

- The basis for backcasting opex is detailed above in section 34.3 - Methodology above.
- These reflect the best estimates as they reflect Energex's interpretations of CoS changes and are the only source of information available.

34.5 Explanatory notes

- SCS Inspections (DOPEX0101) includes:
  - increased costs in 2011-12 when a provision was recognised following the identification of a manufacturing fault on certain overhead service lines which had led to the premature deterioration of these cables.
  - decreased costs in 2012-13 when a revised estimate to complete the inspection program resulted in a partial reversal of the provision.
- SCS Planned Maintenance (DOPEX0102) increased significantly in 2006-07 due to changed maintenance cycles resulting from the 2004 Electricity Distribution and Service Delivery (EDSD) Review.
- SCS Emergency response/storms (DOPEX0105) shows a significant increase in 2010-11 and 2012-13 due to restoration associated with various weather events, in particular the January 2011 floods and ex-Tropical Cyclone Oswald in January 2013.
- ACS Other network maintenance costs (DOPEX0106).
- SCS Network operating cost (DOPEX0107) increased in 2013-14 due to the implementation of the Distribution Management System, which provides real-time information on power flow, network status, outages and network changes.
- SCS Other operating costs (DOPEX01113) includes:
  - Costs attributable to the preparation, submission and implementation of the 2010 determination (in 2009-10), following transfer from jurisdictional regulation under the Queensland Competition Authority to national regulation under the AER. Similar costs are included in 2013-14 in preparation for the 2015 determination.
  - corporate restructuring costs from 2011-12 to 2013-14.

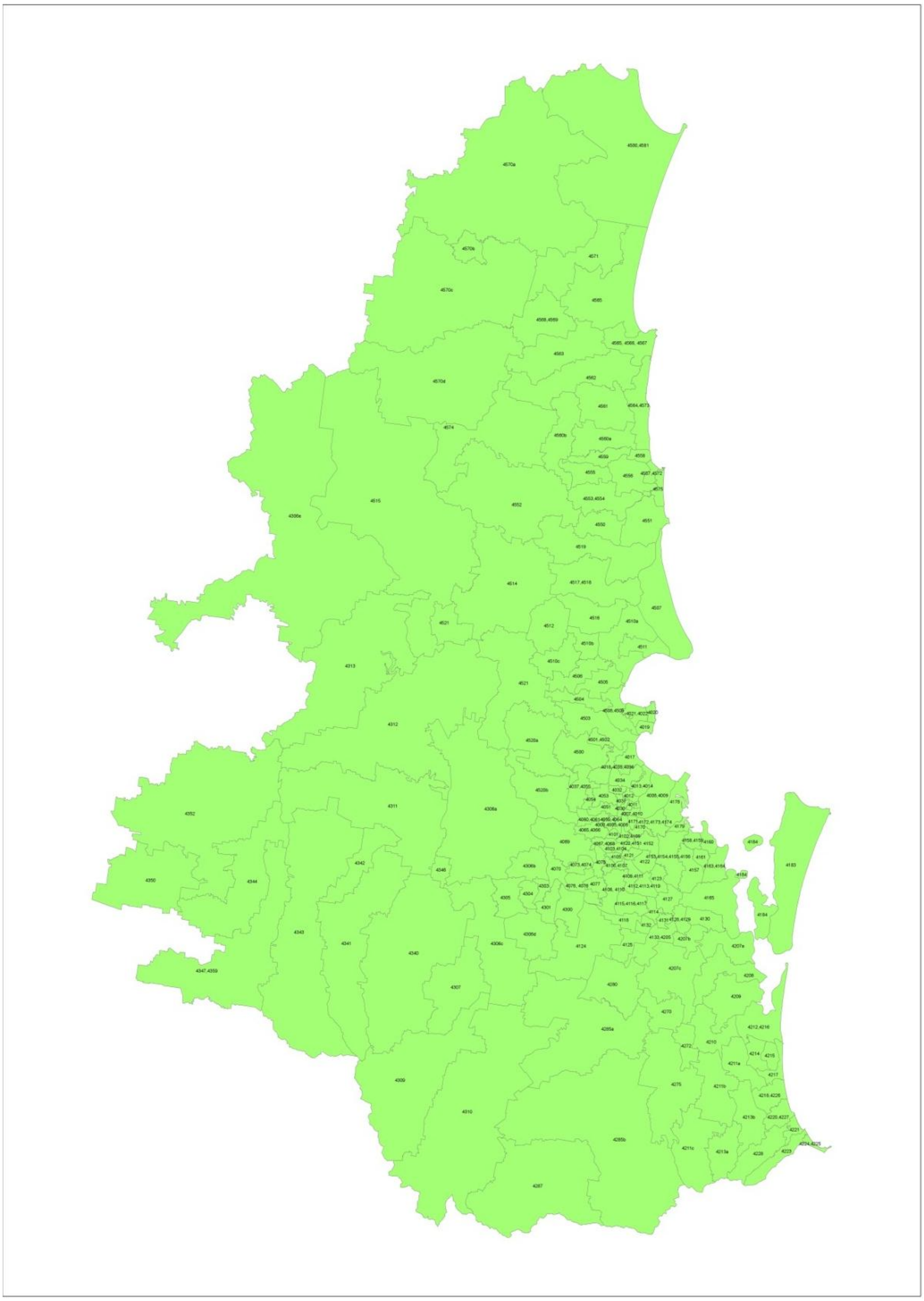
Appendix 1 – Mapping Table

Mapping Table – Reset RIN Categories vs Annual Performance RIN Categories (Capex by Reason)

Service Classification	Reset RIN Categories	Annual Performance RIN (Capex by Reason)
System		
Standard Control	Augmentation	Corporate Initiated Demand
Standard Control	Augmentation	Other
Standard Control	Augmentation	Reliability & Quality Improvements
Standard Control	Connections and customer initiated	Customer Initiated Demand
Standard Control	Replacement	Asset Replacement
Standard Control	Replacement	Other
Alternative Control	Fee based services	Customer Initiated Demand
Alternative Control	Quoted services	Customer Initiated Demand
Alternative Control	Street lighting	Customer Initiated Demand
Non System excluding Control Centre - SCADA	Non-network	Other

Appendix 2 – Vegetation Management Zones Map

For a detailed view of the vegetation management zones please refer to the attached pdf.



Appendix 3 – Cost Element Mapping to Input Table Categories

Reset RIN Input Table Category	Cost Element Hierarchy	Cost Element examples *(not an exhaustive list)*
Direct Material Cost	Energy Related Cost of Sales	Electricity Purchases (including Solar PV FiT payments) QCA Levy ESO Levy
	Materials	Stores issues Workwear Direct purchases
	Other Cost of Sales	Customer incentive payment
Direct Labour Cost	Employee Benefits	Ordinary time Overtime Labour hire Annual leave Long service leave Sick leave Workers compensation Superannuation Payroll tax Study assistance Redundancy payments Staff bonus
Contractor Cost	Contractors	Contractors – operations Contractors – professional services Legal professional services
	Consultants	Consultants

Reset RIN Input Table Category	Cost Element Hierarchy	Cost Element examples *(not an exhaustive list)*
	SPARQ Solutions Charges	SPARQ Solutions SLA SPARQ Solutions asset usage fee
Other Cost	Occupancy Expense	Rent and leases Rates Electricity and gas Repairs and maintenance Cleaning Waste Security
	Transport	Fleet management fees Fuel and oils Registration and insurance Scheduled maintenance Accident repairs Vehicle hire Car parking and tolls
	Marketing	Advertising Direct marketing
	Other operating expenses	Audit fees Customer compensation Stationery Postage and couriers Subscriptions Bank fees

Appendix 4 – Maintenance Other Costs

TABLE 2.8.2 - COST METRICS FOR ROUTINE AND NON-ROUTINE MAINTENANCE

							Planned					Reactive
			ROUTINE MAINTENANCE COST ($000'S)	ROUTINE MAINTENANCE COST ($000'S)	ROUTINE MAINTENANCE COST ($000'S)	ROUTINE MAINTENANCE COST ($000'S)	ROUTINE MAINTENANCE COST ($000'S)	NON-ROUTINE MAINTENANCE COST ($000'S)	NON-ROUTINE MAINTENANCE COST ($000'S)	NON-ROUTINE MAINTENANCE COST ($000'S)	NON-ROUTINE MAINTENANCE COST ($000'S)	NON-ROUTINE MAINTENANCE COST ($000'S)
	MAINTENANCE ACTIVITY	MAINTENANCE ASSET CATEGORY	2009/10	2010/11	2011/12	2012/13	2013/14	2009/10	2010/11	2011/12	2012/13	2013/14
	POLE TOP, OVERHEAD LINE & SERVICE LINE MAINTENANCE	POLE TOPS AND OVERHEAD LINES	68.47	144.17	186.25	213.87	839.60	21,050.52	15,791.19	21,221.47	22,604.70	21,853.20
	POLE TOP, OVERHEAD LINE & SERVICE LINE MAINTENANCE	SERVICE LINES	-	-	-	-	-	775.33	531.31	439.48	56.66	1,222.56
	POLE INSPECTION AND TREATMENT	ALL POLES	6,622.99	6,784.04	6,167.64	6,145.78	5,878.29	156.35	- 0.45	18,382.04	- 5,214.02	9.90
	OVERHEAD ASSET INSPECTION	ALL OVERHEAD ASSETS	1,910.00	1,338.11	1,352.81	1,646.04	2,790.24	651.12	463.42	548.31	373.36	520.44
	NETWORK UNDERGROUND CABLE MAINTENANCE: BY VOLTAGE	LV - 11 TO 22 KV	-	158.17	505.67	283.66	308.95	2,238.04	2,877.32	1,943.75	2,274.54	1,890.51
	NETWORK UNDERGROUND CABLE MAINTENANCE: BY VOLTAGE	33 KV AND ABOVE	-	-	-	-	-	2,267.73	2,514.80	2,208.13	2,749.53	1,476.80
	NETWORK UNDERGROUND CABLE MAINTENANCE: BY LOCATION	CBD	-	2.69	8.60	4.82	5.25	76.60	91.67	70.58	85.41	57.24
	NETWORK UNDERGROUND CABLE MAINTENANCE: BY LOCATION	NON-CBD	-	155.48	497.07	278.84	303.70	4,429.17	5,300.46	4,081.30	4,938.66	3,310.07
	DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION TRANSFORMERS	3,519.93	2,295.19	1,810.32	1,391.46	1,224.96	16.12	-	2.02	1,144.21	979.15
	DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION SWITCHGEAR (WITHIN-SUBSTATIONS AND STAND-ALONE SWITCHGEAR)	-	-	-	-	1,022.51	-	-	1,227.70	1,991.68	-
	DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION - OTHER EQUIPMENT	0.43	26.33	15.90	- 0.04	-	-	-	-	-	1.38
	DISTRIBUTION SUBSTATION EQUIPMENT & PROPERTY MAINTENANCE	DISTRIBUTION SUBSTATION - PROPERTY	-	-	-	-	-	493.41	408.37	488.56	303.35	612.02
	ZONE SUBSTATION EQUIPMENT MAINTENANCE	TRANSFORMERS - ZONE SUBSTATION	658.65	709.97	794.45	921.48	705.62	1,998.81	686.74	1,294.56	2,051.14	1,855.45
	ZONE SUBSTATION EQUIPMENT MAINTENANCE	TRANSFORMERS - DISTRIBUTION	-	-	-	-	-	-	-	-	-	-
	ZONE SUBSTATION EQUIPMENT MAINTENANCE	TRANSFORMERS - HV	-	-	-	-	-	-	-	-	-	-
	ZONE SUBSTATION EQUIPMENT MAINTENANCE	ZONE SUBSTATION - OTHER EQUIPMENT	499.43	745.51	815.23	787.19	1,536.57	4,141.82	5,602.88	5,918.38	5,720.49	4,327.57
	ZONE SUBSTATION PROPERTY MAINTENANCE	ALL ZONE SUBSTATION PROPERTIES	56.71	60.90	38.73	201.61	207.99	2,597.33	3,396.30	3,312.58	3,355.15	3,164.18
	PUBLIC LIGHTING MAINTENANCE	MINOR ROADS	-	-	-	-	-	5,685.02	5.02	31.32	16.61	-
	PUBLIC LIGHTING MAINTENANCE	MAJOR ROADS	-	-	-	-	-	2,208.12	1.97	12.39	6.63	-
	SCADA & NETWORK CONTROL MAINTENANCE	SCADA & NETWORK CONTROL MAINTENANCE	110.71	271.26	336.95	615.91	859.72	-	-	29.40	-	8.12
	PROTECTION SYSTEMS MAINTENANCE	PROTECTION SYSTEMS MAINTENANCE	1,194.07	1,311.22	638.54	1,373.94	1,842.58	390.11	113.35	160.13	182.49	252.18
Other	SUBTRANSMISSION ASSET MAINTENANCE - FOR DNSPS WITH DUAL FUNCTION ASSETS	SUBTRANSMISSION ASSET MAINTENANCE - FOR DNSPS WITH DUAL FUNCTION ASSETS		-	-	-	-		-	-	-	-
Other	ZONE SUBSTATION INSPECTION	ALL SUBSTATION ASSETS	58.56	30.25	24.53	45.18	49.04					-
Other	ZONE SUBSTATION INSPECTION	ALL ZONE SUBSTATION ASSETS	191.54	244.92	287.38	322.21	508.10	51.24	251.49	186.88	187.86	181.87
Other	DISTRIBUTION ASSET INSPECTION	DISTRIBUTION SUBSTATIONS	1,877.45	1,788.67	1,729.30	933.23	961.09	51.93	185.70	845.47	247.81	-
Other	DISTRIBUTION POLE MOUNTED PLANT MAINTENANCE	ALL DISTRIBUTION PMP (TRANSFORMERS, RECLOSERS, REGULATORS, SECTIONALISERS)	-	-	-	-	133.54	499.75	526.57	498.74	1,023.35	906.49
Other	UNDERGROUND FEEDER ASSET INSPECTION	ALL UNDERGROUND FEEDER ASSETS	135.20	266.67	721.28	901.87	210.52	222.48	245.15	350.07	305.84	1,360.08
Other	PILOTS	PILOTS	7.20	7.40	10.00	15.19	7.93	499.15	269.63	159.94	151.43	64.75
	Ground Clearance - access tracks	Ground Clearance - access tracks	0	0	0	0	-		1,424.79	1,682.77	661.96	620.26
	[OTHER MAINTENANCE ACTIVITY 2] (DNSP TO NOMINATE)	DNSP TO NOMINATE					-					-

Appendix 5 – Explanation of functional areas

Network Overhead

Network Overhead costs refer to the provision of network, control and management services that cannot be directly identified with specific operational activity (such as routine maintenance, vegetation management, etc.).

For distribution NSPs, Network Overhead includes the following:

- management (not directly related to any of the functions listed below);
- network planning (i.e. system planning);
- network control and operational switching personnel;
- quality and standard functions including standards & manuals, asset strategy (other than network planning), compliance, quality of supply, reliability, and network records (e.g. geographical information systems (GIS));
- project governance and related functions including supervision, procurement, works management, logistics and stores; and
- Other including training, OH&S functions, training, network billing and customer service & call centre.

In addition to the above, Network Overhead includes:

- Meter reading;
- Advertising/marketing;
- Guaranteed Service Level (GSL) payments;
- National Energy Customer Framework (NECF)-related expenses;
- Demand side management (DSM) expenditure/ non-network alternatives; and
- Levies.

Management – includes all costs associated with general management of the network business, i.e. management and management support staff not directly involved with any other network overhead functions (i.e. network planning, network control and operational switching personnel, quality and standard function, project governance and related functions, training, network billing and customer service and call centre). This incorporates expenditure not directly attributable to the performance of capital, maintenance and operating work and is incurred within the Energex departments identified below. It also includes the non-bookable time associated with team briefs, meetings, training, etc.

- Asset Management Office - responsible for the development and management of strategies, policies, and procedures associated with managing the distribution network.
- Mains Design and Power System Engineering – responsible for the provision of engineering design services and solutions for infrastructure.

Network Planning – includes all costs associated with developing visions, strategies or plans for the development of the network. This includes functions such as demand forecasting, network analysis, preparation of planning documentation, area plans, and the like, as well as management directly associated with these functions. This incorporates expenditure not directly attributable to the performance of capital, maintenance and operating work and are incurred within the following Energex departments:

- Network Capital Planning – responsible for forecasting demand and energy to produce the capital development program for the network as well as the provision of business cases and approvals for major project augmentation of the transmission sub-transmission and distribution networks;
- Demand and Risk Management – responsible for demand side management and program of work optimisation to enable control and management of risks on the Energex network; and
- Environment - undertakes environmental risk and compliance activities, performs environmental assessments (e.g. environmental requests, contaminated land, national parks, fauna, and vegetation), and manages sustainability (e.g. recycling and carbon footprint).

Network Control and Operational Switching Personnel - Includes all costs associated with network control (system operations). This includes functions such as planning and scheduling of switching activities, control room staff, management of field crews, dispatch operators, associated support staff, as well as management directly associated with these functions. This function also includes all costs associated with field crews that undertake the operational switching of the network to facilitate network access or restoration, as well as any directly associated local management that is not included in the Network Control category. Costs are principally incurred within the following Energex departments:

- Network Operations - responsible for: network alarm monitoring and response; customer telephone response; trouble call management and after hours dispatch; disaster coordination; network load management; network supply standards and consulting services; planned and emergency network access and network control; and the Service Target Performance Incentive Scheme (STPIS).
- Control and Secondary Systems – responsible for the building, installation, commissioning and maintenance of SCADA and telecommunications services to the distribution network.

Quality and Standard Functions - Includes all costs associated with management of the quality of supply, supply reliability, etc. It also includes all costs associated with the development, maintenance and compliance with network technical standards, service standards, quality of supply standards, etc. This incorporates expenditure not directly attributable to the performance of capital, maintenance and operating work and are incurred within the following Energex departments:

- System Engineering and Operational Technology and Telecommunications – responsible for the provision of technical standards for the electricity and telecommunications networks, technical specifications and tender evaluations for network plant and materials, protection engineering services and network design solutions.
- Network Asset Management Group – responsible for the development and implementation of asset management strategies and plans through an integrated CAPEX/OPEX POW, to achieve financial and non-financial targets, in conjunction with resource groups.
- Network Property Data and Coordination – responsible for ensuring ongoing and access to accurate network data through providing strategic initiatives around systems and processes that support the Network business in the management of adherence to standards.

Project Governance and Related Functions - Includes all costs associated with the approval and management control of network projects or programs. This includes the cost of functions such as project management offices, works management, or project control groups where these costs are not directly charged to specific projects or programs. This incorporates expenditure not directly attributable to the performance of capital, maintenance and operating work and is incurred in four areas:

- Supervision – This function is accountable for oversight of the delivery of program of work.
- Procurement – This function includes all activities associated with the identification and implementation of 'Best Practice' procurement strategies that contribute to Energex's overall business objectives including achieving value for money and ensuring probity and accountability for outcomes.
- Works Management – This function includes all activities required to ensure that the Network Program of Work is established and delivered according to network priorities, budget and by making the best use of available resources.
- Logistics and Stores (POW Material Management) – this function is responsible for storing and handling materials used in Energex's Program of Work (POW). These costs are also treated as materials on costs in accordance with Energex's AER-approved CAM.

OHS – Includes expenditure associated with safety and specialist post and pre-trade training such as cable jointing and safety courses to staff

Customer Services – Includes all costs associated with activities arising from specific requests by customers that requires work on the Energex network. It includes:

- Attending to and resolving loss of supply and cold water complaints, and other miscellaneous network related concerns raised by customers
- Ground inspections of overhead service connections
- Assessment of meters, relays and CTs to ensure compliance with standards
- Costs associated with payments to customers on account of Energex failing to meet agreed service level standards
- Call centre costs

Meter Reading, Network Billing and Network Monitoring - This function encompasses all activities associated with metering including the reading of meters, data storage and network billing. Metering function comprises two main activities, being metering operations and energy market roles:

- Metering Operations - involves the role of official Responsible Person (RP) for Energex, the regulatory and compliance role for metering and a focus on metering systems, new technology and equipment including systems integration and metering strategy.
- Energy Market Roles includes: Metering Data Agency (MDA) and Meter Data Provider (MDP) involving the collection, validation, substitution, processing, reporting and delivery of meter data to AEMO and relevant market participants in accordance with the National Electricity Rules.
- Network Billing is responsible for the calculation of network distribution use of system (DUOS) charges at the NMI level, aggregation of accounts to a retailer level and publication of a statement of charge to each NEM retailer monthly.

Demand Side Management (DSM) Initiatives - This function encompasses activities associated with the development and implementation of a range of initiatives to manage customer demand. It also includes the expenditure associated with the Demand Management Innovation Allowance (DMIA) funding.

Corporate Overhead

Corporate Overhead costs refer to the provision of corporate support and management services by the corporate office that cannot be directly identified with specific operational activity.

Corporate overhead costs typically include those for executive management, legal and secretariat, human resources, finance, and other corporate head office activities or departments.

- Office of CEO - Provides leadership to position Energex as a safe, efficient, environmentally sustainable and commercial organisation.

- Legal and Secretariat - is responsible for the management of legal issues, legal advice and ligation and provision of legal support to economic regulation issues and bodies.

- Audit - Provision of assurance over effectiveness of Internal Control.

- Strategy and Regulation – Includes costs incurred within the following departments:
  - Corporate Governance Management Office - Responsible for the development and management of a corporate governance framework, including governance policies, to foster assurance of Energex's system for ethics and integrity.
  - Regulatory Affairs - Manages the current determination, ensures compliance with regulatory obligations and is the interface between Energex and Regulators
  - Corporate Risk and Compliance – Responsible for the development, establishment and implementation of a corporate risk management framework and approach and compliance program to manage Energex business risk and supports confidence to management and the board.
  - Corporate Strategy and Planning - Develops and deploys Energex's strategic direction, corporate and business planning, strategic policies and corporate sustainability.
  - Revenue Strategy - develop and deploy revenue and pricing strategies which optimise outcomes of the regulatory revenue reset process and secures Energex's future funding requirements.

- Human Resources - Resourcing and recruiting, new starter information, day to day people leadership and HR activities, payroll information, training and development, health and wellbeing and internal communication.

- Finance – Includes costs incurred within the following departments:
  - Financial Control - is responsible for the provision of financial and regulatory reporting (e.g. financial statements, RIN financial information, external audit, monthly financial reporting, balance sheet, Ellipse finance)
  - Taxation - is responsible for the management of Energex's tax risk compliance and advising activities (e.g. GST, Fringe Benefit Tax, Payroll Tax, Income Tax).
  - CFO Management Office - provides leadership and management to Energex to deliver balanced commercial outcomes to the business for initiatives that will assist Energex to deliver on its future vision.
  - Business Performance and Analysis - Provides Group and Divisional financial reporting, budgeting, forecasting, Investment Review Committee governance and business case management. It also undertakes treasury, balance sheet, Fitch Credit Review and guarantee register functions.

- Business Support Services – delivers a range of administrative and support services including accounts payable, accounts receivable, corporate insurance, records and information management.

- Business Operations and Performance – responsible for delivering current operational performance, building capability for the delivery of future performance and managing risk.

- Field Support Services - Includes costs incurred within the following departments:
  - Field Support Management Office
  - Generator Services - provision of generation services as network support during outages required for the performance of maintenance activities
  - RedEquip - Supply, manage, test and maintain Energex field equipment and associated services
  - Laboratory Services - Calibration and testing of Energex equipment

- Stakeholder Engagement and Management – Includes costs incurred within the following departments:
  - Customer Advocacy - is responsible for the management of relationships with customers encompassing customer communication, complaints and community liaison.
  - Government Relations - is responsible for handling escalated customer complaints and enquiries from Energy and Water Ombudsman, Minister's Office, State and Federal MP's, OGOC and Government Departments and Government Briefing Notes.
  - Corporate Communications - This function involves the management of media relations, community consultation and internal communications (excluding sponsorships). The function also includes the maintenance and enhancement of corporate marketing requirements, including brand, research, marketing communications and website communications (e.g. emergency information) and investing to build stronger community partnerships in line with Energex strategy (e.g. advertising and community education about safety and demand management).

- Property - This function is responsible for ensuring Energex sites are efficient, effective, safe and green. Responsibilities include security, facility maintenance, property acquisitions and disposals, lease and licence management, and compliance reporting audits.

- Fleet - The indirect costs associated with operating and maintaining Energex's leased or owned vehicles, (excluding depreciation and amortisation) that are used in the construction, operation or maintenance of the electricity network. These costs are also treated as fleet oncosts in accordance with Energex's AER-approved CAM.

Appendix 6 – Provisions Movements

Requirements relating to Provisions

17.2 If, in a given year, there is an increase in the amount of a provision, provide reasons for this increase, including:

a) The expected timing of any resulting outflows of economic benefits;
b) An explanation of the uncertainties about the amounts or timing of the outflows;
c) Any supporting consultant's advice, including actuarial reports; and
d) If there is no supporting consultant's advice, the process and assumptions Energex used in determining the increase in the provision.

Response

Provision name: Provision for Dividends

Brief description: Provision is made for the amount of dividend declared by the Board but not distributed at the end of the reporting period.

2011 $177,242.833k increase

Reason for increase: Dividend Provision was recognised for the first time in 2011 consistent with the annual regulatory accounts.

a) Dividends are due to be paid to the Queensland State Government within six months after the end of the financial year (as per *Government Owned Corporations Act 1993* (GOC Act) s.131).
b) The amount of dividend proposed is 80% of net operating profit after tax. This % amount is consistent with the Statement of Corporate Intent which is approved by the shareholding Ministers. The timing of the settlement is stipulated in the GOC Act.
c) Not applicable – as no consultant's advice is sought in these matters.
d) When determining the dividend provision each year, Energex follows the process which is prescribed in the GOC Act.

2012 $36,029.330k increase

Reason for increase: Dividend Provision increased in line with the increase in net operating profit after tax upon which the dividend is calculated.

a) Dividends are due to be paid to the Queensland State Government within six months after the end of the financial year (as per *Government Owned Corporations Act 1993* (GOC Act) s.131).
b) The amount of dividend proposed is 80% of net operating profit after tax. This % amount is consistent with the Statement of Corporate Intent which is approved by the shareholding Ministers. The timing of the settlement is stipulated in the GOC Act.

c) Not applicable – as no consultant's advice is sought in these matters.
d) When determining the dividend provision each year, Energex follows the process which is prescribed in the GOC Act.

2013 $64,365.927k increase

Reason for increase: Dividend Provision increased in line with the increase in net operating profit after tax upon which the dividend is calculated.

a) Dividends are due to be paid to the Queensland State Government within six months after the end of the financial year (as per *Government Owned Corporations Act 1993* (GOC Act) s.131).
b) The amount of dividend proposed is 80% of net operating profit after tax. This % amount is consistent with the Statement of Corporate Intent which is approved by the shareholding Ministers. The timing of the settlement is stipulated in the GOC Act.
c) Not applicable – as no consultant's advice is sought in these matters.
d) When determining the dividend provision each year, Energex follows the process which is prescribed in the GOC Act.

2014 $105,651.544k increase

Reason for increase: Dividend Provision increased in line with the increase in net operating profit after tax upon which the dividend is calculated.

a) Dividends are due to be paid to the Queensland State Government within six months after the end of the financial year (as per *Government Owned Corporations Act 1993* (GOC Act) s.131).
b) The amount of dividend proposed is 80% of net operating profit after tax. This % amount is consistent with the Statement of Corporate Intent which is approved by the shareholding Ministers. The timing of the settlement is stipulated in the GOC Act.
c) Not applicable – as no consultant's advice is sought in these matters.
d) When determining the dividend provision each year, Energex follows the process which is prescribed in the GOC Act.

Provision name: Provision for Site Restoration - Toowoomba

Brief description: Provision is raised for the obligation to restore a site at Toowoomba. The amount has been determined by an independent assessment to rehabilitate the site.

2012 $19,836.408k increase

Reason for increase: The rehabilitation provision for the Neil Street property in Toowoomba was raised as a result of Energex's obligation to restore the site being recognised.

a) The expected timing of resulting outflows of economic benefits was that the majority of project costs would be incurred within 18 months of project inception.

b) A rehabilitation project by nature involves estimates of both amount and timing due to the uncertainty around the amount of contaminated soil needed to be removed. Energex engaged consultants to determine the cost of completing the project.
c) A Remediation Action Plan was used to assist with determining the provision to rehabilitate the site. (Refer to Provisions Schedule 1 - Appendix A)
d) Not applicable.

2013 $(10,859.452)k decrease

Reason for decrease: The rehabilitation provision for the Neil Street property in Toowoomba has been utilised for remedial works.

a) The expected timing of resulting outflows of economic benefits was that the majority of project costs would be incurred within 18 months of project inception.
b) A rehabilitation project by nature involves estimates of both amount and timing due to uncertainty around the amount of contaminated soil needed to be removed. Energex engaged consultants to determine estimates for both cost and length of time to substantially complete the project.
c) A Remediation Action Plan was used to assist with determining the provision to rehabilitate the site. (Refer to Provisions Schedule 1 - Appendix A)
d) Not applicable.

2014 $(8,330.104)k decrease

Reason for decrease: The rehabilitation provision for the Neil Street property in Toowoomba has been utilised for remedial works.

a) The expected timing of resulting outflows of economic benefits was that the majority of project costs would be incurred within 18 months of project inception.
b) A rehabilitation project by nature involves estimates of both amount and timing due to uncertainty around the amount of contaminated soil needed to be removed. Energex engaged consultants to determine estimates for both cost and length of time to substantially complete the project.
c) A Remediation Action Plan was used to assist with determining the provision to rehabilitate the site. (Refer to Provisions Schedule 1 - Appendix A)
d) Not applicable.

Provision name: Provision for Site Restoration - Other

Brief description: Provision is raised for the obligation to restore sites in the future, on expiration of associated contracts or when the obligation arises in the course of business.

2011 $283.602k increase

Reason for increase: The provision for site restoration - other was recognised for the first time in 2011 consistent with the annual regulatory accounts.

a) The expected timing of resulting outflows of economic benefits is 12 months.
b) These make good provisions involve estimating the work required to restore a site upon expiration of associated contract.
c) Not applicable.
d) The provision is determined with reference to historical data on the cost to restore, repair, dismantle or rehabilitate a site.

2012 $(283.602)k decrease

Reason for decrease: Upon expiration of the associated contract for a property lease, the make good provision was partially utilised, with the remainder written back once it was deemed to be in excess of the current obligation.

a) Not applicable as the provision is nil at 30 June 2012.
b) Not applicable as the provision is nil at 30 June 2012.
c) Not applicable as the provision is nil at 30 June 2012.
d) Not applicable as the provision is nil at 30 June 2012.

2013 $1,431.564k increase

Reason for increase: Make good provisions were raised upon review of various property leases whereby the lease agreement contained make good clauses which are triggered when the contract is terminated.

a) The terms of the various lease agreements ranged from less than 12 months to 14 years with the majority occurring within the next five years.
b) The provision to make good the premises is based on the future estimated condition of the premises and the amount of work required to restore a site to the agreed standard as per the lease agreement.
c) Not applicable.
d) The provision is determined with reference to historical data on the cost to restore, repair, dismantle or rehabilitate a site.

2014 $(16.010)k decrease

Reason for decrease: Whilst current make good provisions were increased during the period upon review of the estimated costs required to settle the future obligations, this increase was more than offset by the utilisation of the provision upon termination of a lease.

a) The terms of the various lease agreements ranged from one year to 13 years with the majority occurring within the next six years.

b) The provision to make good the premises is based on the future estimated condition of the premises and the amount of work required to restore a site to the agreed standard as per the lease agreement.
c) Not applicable.
d) The provision is determined with reference to historical data on the cost to restore, repair, dismantle or rehabilitate a site.

Provision name: Provision for Public Liability Insurance

Brief description: Provision is raised to cover the excess on any public liability insurance claim (also referred to as self insurance).

2006 $476.777k increase

Reason for increase: The provision for public liability insurance increased this year due to two significant events being provided for in addition to the standard self insurance allowance.

a) The expected timing of resulting outflows of economic benefits for property claims is expected to occur close to the event whereas personal injury claims can vary. Provisions are required to be maintained for six years as claims can go back for a maximum of six years for property claims, and three years for personal injury claims.
b) Due to the uncertainties around the amounts or timing of events that lead to insurance claims, Energex engages independent insurance brokers who provide actuarial advice to support the provisions being raised. In addition to this, the yearly provision balances are subject to annual review by the insurance manager to ensure provisions at balance date remain appropriate since valuation date.
c) Independent insurance brokers have provided actuarial reports to support the self insurance provisions being raised for any particular year. These actuarial reports are prepared for the sole and exclusive use of Energex and are considered proprietary to the insurance broker and, as such, may not be made available to anyone other than Energex, unless written permission from the insurance broker is obtained.
d) Not applicable.

2007 $612.165k increase

Reason for increase: The provision for public liability insurance increased this year due to the standard self insurance allowance being raised, whilst there was low claims experience throughout the year.

a) The expected timing of resulting outflows of economic benefits for property claims is expected to occur close to the event whereas personal injury claims can vary. Provisions are required to be maintained for six years as claims can go back for a maximum of six years for property claims, and three years for personal injury claims.
b) Due to the uncertainties around the amounts or timing of events that lead to insurance claims, Energex engages independent insurance brokers who provide actuarial advice to

support the provisions being raised. In addition to this, the yearly provision balances are subject to annual review by the insurance manager to ensure provisions at balance date remain appropriate since valuation date.

c) Independent insurance brokers have provided actuarial reports to support the self insurance provisions being raised for any particular year. These actuarial reports are prepared for the sole and exclusive use of Energex and are considered proprietary to the insurance broker and, as such, may not be made available to anyone other than Energex, unless written permission from the insurance broker is obtained.

d) Not applicable.

2008 $672.087k increase

Reason for increase: The provision for public liability insurance increased this year due to the standard self insurance allowance being raised, whilst, as in 2007, there was low claims experience throughout the year.

a) The expected timing of resulting outflows of economic benefits for property claims is expected to occur close to the event whereas personal injury claims can vary. Provisions are required to be maintained for six years as claims can go back for a maximum of six years for property claims, and three years for personal injury claims.

b) Due to the uncertainties around the amounts or timing of events that lead to insurance claims, Energex engages independent insurance brokers who provide actuarial advice to support the provisions being raised. In addition to this, the yearly provision balances are subject to annual review by the insurance manager to ensure provisions at balance date remain appropriate since valuation date.

c) Independent insurance brokers have provided actuarial reports to support the self insurance provisions being raised for any particular year. These actuarial reports are prepared for the sole and exclusive use of Energex and are considered proprietary to the insurance broker and, as such, may not be made available to anyone other than Energex, unless written permission from the insurance broker is obtained.

d) Not applicable.

2009 $(936.301)k decrease

Reason for decrease: The provision for public liability insurance decreased this year due to the reversal of prior year provisions deemed no longer necessary. This included the reversal of the 2003 annual self insurance provision as well as the reversals of the residual balances pertaining to two separate provisions raised relating to significant events which occurred in 2005 and 2006. These reversals were offset by an increase to the annual provision being raised due to a review conducted by the independent insurance broker. Based on the actuarial valuation, the annual provision has been increased from $650k to $875k in 2009.

a) The expected timing of resulting outflows of economic benefits for property claims is expected to occur close to the event whereas personal injury claims can vary. Provisions are required to be maintained for six years as claims can go back for a maximum of six years for property claims, and three years for personal injury claims.

b) Due to the uncertainties around the amounts or timing of events that lead to insurance claims, Energex engages independent insurance brokers who provide actuarial advice to support the provisions being raised. In addition to this, the yearly provision balances are subject to annual review by the insurance manager to ensure provisions at balance date remain appropriate since valuation date.
c) Independent insurance brokers have provided actuarial reports to support the self insurance provisions being raised for any particular year. These actuarial reports are prepared for the sole and exclusive use of Energex and are considered proprietary to the insurance broker and, as such, may not be made available to anyone other than Energex, unless written permission from the insurance broker is obtained.
d) Not applicable.

2010 $446.917k increase

Reason for increase: The provision for public liability insurance increased this year due to the standard self insurance allowance being raised, whilst there was low claims experience throughout the year. The standard annual self insurance provision has been increased based on an actuarial valuation performed by the independent insurance broker which saw the annual provision being raised increase from $875k to $920k.

a) The expected timing of resulting outflows of economic benefits for property claims is expected to occur close to the event whereas personal injury claims can vary. Provisions are required to be maintained for six years as claims can go back for a maximum of six years for property claims, and three years for personal injury claims.
b) Due to the uncertainties around the amounts or timing of events that lead to insurance claims, Energex engages independent insurance brokers who provide actuarial advice to support the provisions being raised. In addition to this, the yearly provision balances are subject to annual review by the insurance manager to ensure provisions at balance date remain appropriate since valuation date.
c) Independent insurance brokers have provided actuarial reports to support the self insurance provisions being raised for any particular year. These actuarial reports are prepared for the sole and exclusive use of Energex and are considered proprietary to the insurance broker and, as such, may not be made available to anyone other than Energex, unless written permission from the insurance broker is obtained.
d) Not applicable.

2011 $269.303k increase

Reason for increase: The provision for public liability insurance increased this year primarily due to moderate claims experience during the year. This was offset by a reduction in the annual self insurance allowance being raised, based on an actuarial valuation performed by the independent insurance broker which saw the annual provision being reduced from $920k to $855k.

a) The expected timing of resulting outflows of economic benefits for property claims is expected to occur close to the event whereas personal injury claims can vary. Provisions are required to be maintained for six years as claims can go back for a maximum of six years for property claims, and three years for personal injury claims.
b) Due to the uncertainties around the amounts or timing of events that lead to insurance claims, Energex engages independent insurance brokers who provide actuarial advice to support the provisions being raised. In addition to this, the yearly provision balances are subject to annual review by the insurance manager to ensure provisions at balance date remain appropriate since valuation date.
c) Independent insurance brokers have provided actuarial reports to support the self insurance provisions being raised for any particular year. These actuarial reports are prepared for the sole and exclusive use of Energex and are considered proprietary to the insurance broker and, as such, may not be made available to anyone other than Energex, unless written permission from the insurance broker is obtained.
d) Not applicable.

2012 $(152.342)k decrease

Reason for decrease: The provision for public liability insurance decreased this year due to the reversal of the 2006 provision that was unutilised. Offsetting this was slightly lower than expected claims experience and an increase in the annual self insurance allowance being provided for based on the independent actuarial valuation (2012: $919k versus 2011: $855k).

a) The expected timing of resulting outflows of economic benefits for property claims is expected to occur close to the event whereas personal injury claims can vary. Provisions are required to be maintained for six years as claims can go back for a maximum of six years for property claims, and three years for personal injury claims.
b) Due to the uncertainties around the amounts or timing of events that lead to insurance claims, Energex engages independent insurance brokers who provide actuarial advice to support the provisions being raised. In addition to this, the yearly provision balances are subject to annual review by the insurance manager to ensure provisions at balance date remain appropriate since valuation date.
c) Independent insurance brokers have provided actuarial reports to support the self insurance provisions being raised for any particular year. These actuarial reports are prepared for the sole and exclusive use of Energex and are considered proprietary to the insurance broker and, as such, may not be made available to anyone other than Energex, unless written permission from the insurance broker is obtained.
d) Not applicable.

2013 $(356.524)k decrease

Reason for decrease: The provision for public liability insurance decreased this year due primarily to the reversal of the 2007 provision that was unutilised.

a) The expected timing of resulting outflows of economic benefits for property claims is expected to occur close to the event whereas personal injury claims can vary. Provisions are required to be maintained for six years as claims can go back for a maximum of six years for property claims, and three years for personal injury claims.
b) Due to the uncertainties around the amounts or timing of events that lead to insurance claims, Energex engages independent insurance brokers who provide actuarial advice to support the provisions being raised. In addition to this, the yearly provision balances are subject to annual review by the insurance manager to ensure provisions at balance date remain appropriate since valuation date.
c) Independent insurance brokers have provided actuarial reports to support the self insurance provisions being raised for any particular year. These actuarial reports are prepared for the sole and exclusive use of Energex and are considered proprietary to the insurance broker and, as such, may not be made available to anyone other than Energex, unless written permission from the insurance broker is obtained.
d) Not applicable.

2014 $1,527.725k increase

Reason for increase: The significant increase this year is due to a change in public liability provisions process following an extensive review to streamline the process. The provision now includes claims less than $100k and the first $100k of large/multi claims (including potential claims going back to 2009).

a) The expected timing of resulting outflows of economic benefits for property claims is expected to occur close to the event whereas personal injury claims can vary. Provisions are required to be maintained for six years as claims can go back for a maximum of six years for property claims, and three years for personal injury claims.
b) Due to the uncertainties around the amounts or timing of events that lead to insurance claims, Energex engages independent insurance brokers who provide actuarial advice to support the provisions being raised. In addition to this, the yearly provision balances are subject to annual review by the insurance manager to ensure provisions at balance date remain appropriate since valuation date.
c) Independent insurance brokers have provided actuarial reports to support the self insurance provisions being raised for any particular year. These actuarial reports are prepared for the sole and exclusive use of Energex and are considered proprietary to the insurance broker and, as such, may not be made available to anyone other than Energex, unless written permission from the insurance broker is obtained.
d) Not applicable.

Provision name: Provision for Employee Benefits

Brief description: Provision is raised to cover for payments to employees in future periods for long service leave entitlement accrued, annual leave entitlement accrued, vesting sick leave accrued, days off in lieu accrued and defined benefit deficits.

2006 $8,815.695k increase

Reason for increase: The increase in provision for employee benefits in 2006 is primarily due to an increase in the Long Service Leave and Annual Leave provisions which were driven by a number of factors including increased headcount (9%), an increase in the wage escalation factor from 4.5% to 5.5% and inflation factor from 3.6% to 5.5%.

a) The expected timing of resulting outflows of economic benefits for employee benefits based on historical data is that approximately 28% of total provisions are expected to be settled in the next 12 months.
b) The probability that an employee will be eligible to take Long Service Leave in the future due to current employment is calculated based on current tenure and likelihood of retention.
c) Not applicable for long service leave.
d) Energex reviews the variables used to calculate the provision for long service leave with reference to external sources for inflation factors and discount rates, as well as utilising internal historical data to estimate future trends in retention rates and timing factors.

2007 $10,793.717k increase

Reason for increase: The increase in provision for employee benefits is primarily due to an increase in the Long Service Leave and Annual Leave provisions which were driven by a number of factors including increased headcount (9%) and a shift in the weighting of employee retention probabilities. This was offset by slightly lower probability factors.

a) The expected timing of resulting outflows of economic benefits for employee benefits based on historical data is that approximately 28% of total provisions are expected to be settled in the next 12 months.
b) The probability that an employee will be eligible to take Long Service Leave in the future due to current employment is calculated based on current tenure and likelihood of retention.
c) Not applicable for long service leave or annual leave.
d) Energex reviews the variables used to calculate the provision for long service leave and annual leave with reference to external sources for inflation factors and discount rates, as well as utilising internal historical data to estimate future trends in retention rates and timing factors.

2008 $14,040.048k increase

Reason for increase: The increase in provision for employee benefits is primarily due to an increase in the Long Service Leave and Annual Leave provisions which were driven by a number of factors including increased headcount (4%) and a shift in the weighting of employee retention probabilities.

a) The expected timing of resulting outflows of economic benefits for employee benefits based on historical data is that approximately 28% of total provisions are expected to be settled in the next 12 months.

b) The probability that an employee will be eligible to take Long Service Leave in the future due to current employment is calculated based on current tenure and likelihood of retention.
c) Not applicable for long service leave or annual leave.
d) Energex reviews the variables used to calculate the provision for long service leave and annual leave with reference to external sources for inflation factors and discount rates, as well as utilising internal historical data to estimate future trends in retention rates and timing factors.

2009 $82,842.183k increase

Reason for increase: The significant increase in 2009 is primarily due to the recognition of a deficit for the Defined Benefit Superannuation Fund. Previously, the Fund was in surplus and recognised as an asset.

a) The weighted average duration of the defined benefit obligation in 2009 was 11 years.
b) The defined benefit obligation is a complex calculation using many variables which can affect the amount and timing of the provision, and resulting net balance reported.
c) The Defined Benefit obligation is calculated by an independent actuary on an annual basis. The Defined Benefit balance reported is net of the fund assets. (Refer to Provisions Schedule 1 - Appendix B)
d) Not applicable.

2010 $14,863.348k increase

Reason for increase: The increase in provision for employee benefits is primarily due to an increase in the Long Service Leave and Annual Leave provisions which were driven by a number of factors including increased headcount (4%) and a shift in the weighting of employee retention probabilities. This was offset by a higher discount rate.

a) The expected timing of resulting outflows of economic benefits for employee benefits based on historical data is that approximately 28% of total provisions are expected to be settled in the next 12 months.
b) The probability that an employee will be eligible to take Long Service Leave in the future due to current employment is calculated based on current tenure and likelihood of retention.
c) Not applicable for long service leave or annual leave.
d) Energex reviews the variables used to calculate the provision for long service leave and annual leave with reference to external sources for inflation factors and discount rates, as well as utilising internal historical data to estimate future trends in retention rates and timing factors.

2011 $1,112.730k increase

Reason for increase: The minor increase in the provision for employee benefits consisted of an increase in the long service leave accrued for the 2011 year versus actual leave taken, offset by a decrease in the inflation factor used to estimate the future value of the long service leave liability

a) The expected timing of resulting outflows of economic benefits for employee benefits based on historical data is that approximately 28% of total provisions are expected to be settled in the next 12 months.
b) The probability that an employee will be eligible to take Long Service Leave in the future due to current employment is calculated based on current tenure and likelihood of retention.
c) Not applicable for long service leave.
d) Energex reviews the variables used to calculate the provision for long service leave with reference to external sources for inflation factors and discount rates, and internal historical data to estimate future trends in retention rates and timing factors.

2012 $27,760.813k increase

Reason for increase: The increase in provision for employee benefits in 2012 is mostly due to the lower discount rate used in the calculation of Long Service Leave and Annual Leave. This rate changed from 5.22% in 2011 to 3.04% in 2012.

a) The expected timing of resulting outflows of economic benefits for employee benefits based on historical data is that approximately 28% of total provisions are expected to be settled within the next 12 months.
b) The probability that an employee will be eligible to take Long Service Leave in the future due to current employment is calculated based on current tenure and likelihood of retention.
c) Not applicable for long service leave or annual leave.
d) Energex reviews the variables used to calculate the provision for long service leave and annual leave with reference to external sources for inflation factors and discount rates, as well as utilising internal historical data to estimate future trends in retention rates and timing factors.

2013 $(14,134.422)k decrease

Reason for decrease: The decrease in provision for employee benefits in 2013 is primarily due to a 10% decrease in staff year on year and higher discount rate (2012: 3.04% and 2013: 3.76%).

a) The expected timing of resulting outflows of economic benefits for employee benefits based on historical data is that approximately 28% of total provisions are expected to be settled within the next 12 months.
b) The probability that an employee will be eligible to take Long Service Leave in the future due to current employment is calculated based on current tenure and likelihood of retention.
c) Not applicable for long service leave or annual leave.
d) Energex reviews the variables used to calculate the provision for long service leave and annual leave with reference to external sources for inflation factors and discount rates, as

well as utilising internal historical data to estimate future trends in retention rates and timing factors.

2014 $(3,458.051)k decrease

Reason for decrease: The moderate decrease in provision for employee benefits in 2014 is primarily due to a 9% decrease in staff year on year, which was offset by a shift in the weighting of employee retention rates.

a) The expected timing of resulting outflows of economic benefits for employee benefits based on historical data is that approximately 28% of total provisions are expected to be settled within the next 12 months.
b) The probability that an employee will be eligible to take Long Service Leave in the future due to current employment is calculated based on current tenure and likelihood of retention.
c) Not applicable for long service leave or annual leave.
d) Energex reviews the variables used to calculate the provision for long service leave and annual leave with reference to external sources for inflation factors and discount rates, as well as utilising internal historical data to estimate future trends in retention rates and timing factors.

Provision name: Provision for Redundancy

Brief description: Provision is raised to cover for payments to employees in future periods for redundancy payments.

2011 $344.541k increase

Reason for increase: The modest increase in provision for redundancy relates to roles that were identified as part of a voluntary redundancy scheme.

a) The expected timing of resulting outflows of economic benefits for these redundancies was within twelve months of the reporting date.
b) The expected timing of outflows should be known in advance as one of the criteria to be met when raising a provision for redundancy is that an entity has identified when the termination will occur as part of a detailed plan.
c) Not applicable.
d) Energex calculates the redundancy provision on an individual employee basis.

2012 $(344.541)k decrease

Reason for decrease: The decrease in provision for redundancy represents the utilisation of the prior year's provision.

a) The expected timing of resulting outflows of economic benefits for these redundancies was within twelve months of the reporting date.

b) The expected timing of outflows should be known in advance as one of the criteria to be met when raising a provision for redundancy is that an entity has identified when the termination will occur as part of a detailed plan.
c) Not applicable.
d) Energex calculates the redundancy provision on an individual employee basis.

2013 $12,165.700k increase

Reason for increase: The significant increase in 2013 is due to Energex's deliberate efforts to reduce costs and employee numbers.

a) The expected timing of resulting outflows of economic benefits for these redundancies was within twelve months of the reporting date.
b) The expected timing of outflows should be known in advance as one of the criteria to be met when raising a provision for redundancy is that an entity has identified when the termination will occur as part of a detailed plan.
c) Not applicable.
d) Energex calculates the redundancy provision on an individual employee basis.

2014 $(9,909.066)k decrease

Reason for decrease: The decrease in provision for redundancy is primarily driven by the utilisation of the prior year's provision. This was marginally offset by a new provision raised at 2014 year end, reflecting the continued efforts of the entity to reduce costs and employee numbers.

a) The expected timing of resulting outflows of economic benefits for these redundancies was within twelve months of the reporting date.
b) The expected timing of outflows should be known in advance, as one of the criteria to be met when raising a provision for redundancy is that an entity has identified when the termination will occur as part of a detailed plan.
c) Not applicable.
d) Energex calculates the redundancy provision on an individual employee basis.

Provision name: Provision for Overhead Service Line Inspections

Brief description: Provision is raised for the obligation to inspect overhead service lines which may be faulty. The amount has been determined by management estimation of the cost of the inspection program, based on the number of poles known to be in the relevant areas and the designated cost of inspecting the poles.

2012 $16,804.348k increase

Reason for increase: This provision raised in 2012 was recognised to inspect faulty overhead service lines.

a) The majority of these inspections were completed in 2013, with the remainder completed in 2014.

b) The expected timing of outflows centred around the time taken to inspect the number of known poles to be located in the relevant areas. The costs estimated by management to complete the inspection program were based on the number of poles known to be in the relevant areas and the designated cost of inspecting each pole.
c) Not applicable.
d) Management based their cost estimates on the number of poles known to be in the affected areas and the designated cost of inspecting the poles.

2013 $(12,388.748)k decrease

Reason for decrease: This majority of the provision raised in 2012 to inspect the overhead service lines was utilised in 2013.

a) The majority of these overhead service line inspections were completed in 2013, with the remainder completed in 2014.
b) The expected timing of outflows centred around the time taken to inspect the number of known poles to be located in the relevant areas. The costs estimated by management to complete the inspection program were based on the number of poles known to be in the relevant areas and the designated cost of inspecting each pole.
c) Not applicable.
d) Management based their cost estimates on the number of poles known to be in the affected areas and the designated cost of inspecting the poles.

2014 $(4,247.839)k decrease

Reason for decrease: The remainder of the provision raised in 2012 to inspect the overhead service lines was utilised in 2014.

a) The majority of these overhead service line inspections were completed in 2013, with the remainder completed in 2014.
b) The expected timing of outflows centred around the time taken to inspect the number of known poles to be located in the relevant areas. The costs estimated by management to complete the inspection program were based on the number of poles known to be in the relevant areas and the designated cost of inspecting each pole.
c) Not applicable.
d) Management based their cost estimates on the number of poles known to be in the affected areas and the designated cost of inspecting the poles.

Provision name: Provision for Environmental Offsets

Brief description: Provision is raised for the obligation to counterbalance unavoidable, negative impacts on the natural environment, resulting from an activity or development.

2012 $5,309.934k increase

Reason for increase: Provision for Environmental Offsets was initially recognised in 2012 for environmental obligations required to offset the unavoidable negative impacts on the natural environmental resulting from expected capex. Approximately half of this balance was utilised during the 2013 year when the associated capex was undertaken.

a) The provisions are settled when Energex has sufficiently met the criteria set out by the various legislation to acquit the obligation by purchasing packages offered by the external parties that specialise in executing offsets. Energex is pursuing a bulk offsets strategy which should allow the alignment of program of work projects with the ability to utilise a bank of pre-purchased offsets.
b) A reliable estimate of the amount of the obligation can be determined given the Energex internal environmental group will manage the contracts in place with the specialist external party engaged in executing offsets, and have market information on the costs associated with purchasing offset packages. These pieces of data are broken down to determine a per tree cost for allocation to a specific project. The timing of the outflows of these liabilities is dependent on the program of work and the successful completion of the various dedicated offset projects.
c) Not applicable.
d) The scope and size of the offset needed can be determined using a metric, such as, an area in hectares of a certain type and quality of vegetation or habitat. This tool or methodology is used to indicate the amount and types of environmental values lost due to the impact, and the gains that will be provided with an offset.

2013 $(2,947.134)k decrease

Reason for decrease: The decrease reflects the settling of the initial obligation via the engagement of external parties that specialise in executing offsets.

a) The provisions are settled when Energex has sufficiently met the criteria set out by the various legislation to acquit the obligation by purchasing packages offered by the external parties that specialise in executing offsets. Energex is pursuing a bulk offsets strategy which should allow the alignment of program of work projects with the ability to utilise a bank of pre-purchased offsets.
b) A reliable estimate of the amount of the obligation can be determined given the Energex internal environmental group will manage the contracts in place with the specialist external party engaged in executing offsets, and have market information on the costs associated with purchasing offset packages. These pieces of data are broken down to determine a per tree cost for allocation to a specific project. The timing of the outflows of these liabilities is dependent on the program of work and the successful completion of the various dedicated offset projects.
c) Not applicable.
d) The scope and size of the offset needed can be determined using a metric, such as, an area in hectares of a certain type and quality of vegetation or habitat. This tool or methodology is

used to indicate the amount and types of environmental values lost due to the impact, and the gains that will be provided with an offset.

2014 $(743.907)k decrease

Reason for decrease: The decrease reflects the on-going settlement of the obligations via the engagement of external parties that specialise in executing offsets.

a) The provisions are settled when Energex has sufficiently met the criteria set out by the various legislation to acquit the obligation by purchasing packages offered by the external parties that specialise in executing offsets. Energex is pursuing a bulk offsets strategy which should allow the alignment of program of work projects with the ability to utilise a bank of pre-purchased offsets.
b) A reliable estimate of the amount of the obligation can be determined given the Energex internal environmental group will manage the contracts in place with the specialist external party engaged in executing offsets, and have market information on the costs associated with purchasing offset packages. These pieces of data are broken down to determine a per tree cost for allocation to a specific project. The timing of the outflows of these liabilities is dependent on the program of work and the successful completion of the various dedicated offset projects.
c) Not applicable.
d) The scope and size of the offset needed can be determined using a metric, such as, an area in hectares of a certain type and quality of vegetation or habitat. This tool or methodology is used to indicate the amount and types of environmental values lost due to the impact, and the gains that will be provided with an offset.

Provision name: Provision for Homesuite

Brief description: Provision is raised for Homesuite warranty claims.

2007 $744.915k increase

Reason for increase: The increase represents the residual balance of the provision for Homesuite warranty claims that was transferred from Sun Retail Pty Ltd in 2007.

a) The outflows relating to warranty claims relating to this legacy business were expected to reduce significantly with minimal claims experience going forward.
b) Given this warranty provision relates to a legacy business, the timing and amounts of residual claims is expected to reduce.
c) Not applicable.
d) Not applicable – the homesuite warranty did not increase as such, but rather, was transferred from the Retail business as part of the Trade Sale in 2007.

2008 $(134.011)k decrease

Reason for decrease: The decrease represents the decline in the residual balance of the provision for Homesuite warranty claims that was transferred from Sun Retail Pty Ltd in 2007.

a) The outflows relating to warranty claims relating to this legacy business were expected to reduce with minimal claims experience going forward.
b) Given this warranty provision relates to a legacy business, the timing and amounts of residual claims is expected to reduce.
c) Not applicable.
d) Not applicable.

2009 $(80.883)k decrease

Reason for decrease: The decrease represents the decline in the residual balance of the provision for Homesuite warranty claims that was transferred from Sun Retail Pty Ltd in 2007.

a) The outflows relating to warranty claims relating to this legacy business were expected to reduce with minimal claims experience going forward.
b) Given this warranty provision relates to a legacy business, the timing and amounts of residual claims is expected to reduce.
c) Not applicable.
d) Not applicable.

2010 $(0.986)k decrease

Reason for decrease: The decrease represents the decline in the residual balance of the provision for Homesuite warranty claims that was transferred from Sun Retail Pty Ltd in 2007. The balance of the provision for Homesuite was transferred to Provisions - Other in 2011.

a) The outflows relating to warranty claims relating to this legacy business were expected to reduce with minimal claims experience going forward.
b) Given this warranty provision relates to a legacy business, the timing and amounts of residual claims is expected to reduce.
c) Not applicable.
d) Not applicable.

Provision name: Provision for Other

Brief description: Provision is raised for the pay parity project, the estimated loss for an onerous contract, repairs to EWPs (Elevated Work Platforms), Portable Long Service Leave levies and residual balances relating to the Homesuite warranty.

2008 $6,169.464k increase

Reason for increase: The balance reported in 2008 relates predominantly to a provision raised in relation to the Pay Parity project which was raised this year to address potential pay parity issues identified as part of the extensive pay and role reviews.

a) The settlement of the obligation relating to the Pay Parity project provision was expected to be completed within 2 years of the 2008 reporting date.
b) Uncertainties around the amount and timing of the Pay Parity project arose due to the project still being in its initial stages, with very little sample data upon which to base estimates of impacted employees.
c) Not applicable.
d) Energex engaged an experienced project manager to assist with the assessments which formed the basis of future liability estimates. Only a small sample of employee assessment data was available at this point in time upon which to support the provision estimate.

2009 $(5,582.476)k decrease

Reason for decrease: The original pay parity estimate was revised down once a far greater sample of data was available upon which to base the forecasted impact to remaining employees.

a) The settlement of the obligation relating to the Pay Parity project provision was expected to be completed within 1 year of the 2009 reporting date.
b) Uncertainties around the amount and timing of the Pay Parity project arose due to the project still being in its initial stages, with very little sample data upon which to base estimates of impacted employees. This uncertainty reduced as the project progressed and a larger data sample was available.
c) Not applicable.
d) Energex engaged an experienced project manager to assist with the assessments which formed the basis of future liability estimates.

2010 $1,728.168k increase

Reason for increase: The increase primarily relates to the initial recognition of a provision for outstanding levies claimed by the Building and Construction Industry Authority that oversees compliance with portable long service leave legislation.

a) The expected timing of outflows of the provision for outstanding levies was in the next 12 months as the issue was in the process of being resolved.
b) Uncertainty remained around the interpretation of the scope of projects that are captured by the relevant legislation.
c) Not applicable.
d) The provision for portable long service leave is tracked at the project level.

2011 $352.004k increase

Reason for increase: The increase relates to the initial recognition of a provision for an onerous contract for a legacy business. This was offset by the utilisation of the provision for outstanding portable long service leave levies raised in the prior year.

a) The expected timing of outflows for the onerous contract was for 15 years.
b) The estimated outflows were based on current variables that were stipulated in the contracts that Energex was legally obliged to fulfil.
c) Not applicable
d) Energex used internal modelling to estimate the future cashflows over the next 15 years given the current contracts that were in place.

2012 $(170.030)k decrease

Reason for decrease: The decrease relates to the reversal of a significant portion of the Homesuite provision due to the reduced claims experience. This was offset by a modest increase in the onerous contract provision.

a) The expected timing of outflows for the onerous contract was for 14 years.
b) The estimated outflows were based on current variables that were stipulated in the contracts that Energex was legally obliged to fulfil.
c) Not applicable
d) Energex used internal modelling to estimate the future cashflows over the next 14 years given the current contracts that were in place.

2013 $1,251.323k increase

Reason for increase: The increase relates predominantly to a revision of the onerous contract provision which now equated to a contract termination settlement as opposed to the amount which would be required to fulfil the obligations over the remaining 13 years of the contracts. Additionally, there was a provision raised for repairs to Elevated Work Platforms (EWP).

a) The expected timing of outflows for the onerous contract was reduced to 3 months. The EWP provision was expected to be utilised within the next 6 months.
b) The estimated outflows relating to the onerous contract were now based on the contract termination settlement which was due to take place within the next 3 months. The timing and amount of the EWP repair program is dependent on management’s estimate of the number of vehicles affected.
c) Not applicable.
d) Energex calculated the provision for EWP repairs based on management’s estimate of the number of vehicles impacted.

2014 $(3,183.351) k decrease

Reason for decrease: The decrease relates to the settlement of the provision for onerous contract termination payment and utilisation of the EWP repairs provision.

a) The remaining balance of $72k relates to the residual of the Homesuite Warranty provision which is experiencing a decline in claims experience.
b) The uncertainty of outflows is tied in with the nature of warranty claims.
c) Not applicable.
d) Not applicable.

Energex

Reset RIN

Basis of Preparation

4. Alternative Control Services

October 2014

positive energy

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the fast growing region of South East Queensland. Energex provides distribution services to almost 1.4 million connections, delivering electricity to 2.8 million residents and businesses across the region.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

Group Manager
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Table of Contents

Section 4 – Alternative Control Services

1 BoP 4.1.1 – Public Lighting – Descriptor Metrics Over Current Year

The AER requires Energex to provide the following information relating to RIN Table 4.1.1:

- **The current population of lights, by light type**

Actual Information was provided for all variables in RIN Table 4.1.1.

These variables are a part of Regulatory Template 4.1 – Public Lighting.

1.1 Consistency with Reset RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 1.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The CA RIN instructed that Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER.	This requirement has been taken into account in preparing Reset RIN Regulatory Template 4.1. For details please refer to section 1.3.

Actual Information was provided for all variables in RIN Table 4.1.1.

1.2 Sources

Table 1.2 below sets out the sources from which Energex obtained the required information.

Table 1.2: Information sources

Variable	Source
The current population of lights, by light type	Peace / Oracle

1.3 Methodology

1.3.1 Assumptions

Energex assumed that all instructions provided in the CA RIN were to be applied to the Reset RIN.

Energex applied the following assumptions to obtain the required information:

There are three categories of public lights in Energex's network:

- Rate 1 – Public Lighting supplied, installed, owned and maintained by Energex;
- Rate 2 - Public Lighting for which all supply and installation costs are funded by the Developer or Public Body and then ownership is vested to Energex on completion of the installation. Or where design and construction services are requested to be undertaken by Energex, the supply and installation costs are funded by the Public Body and the lighting installation is supplied, installed, owned and maintained by Energex. In both cases, Energex assumes responsibility for maintenance of the installation; and
- Rate 3 – Public Lighting supplied, installed, owned and maintained by the Public Body.

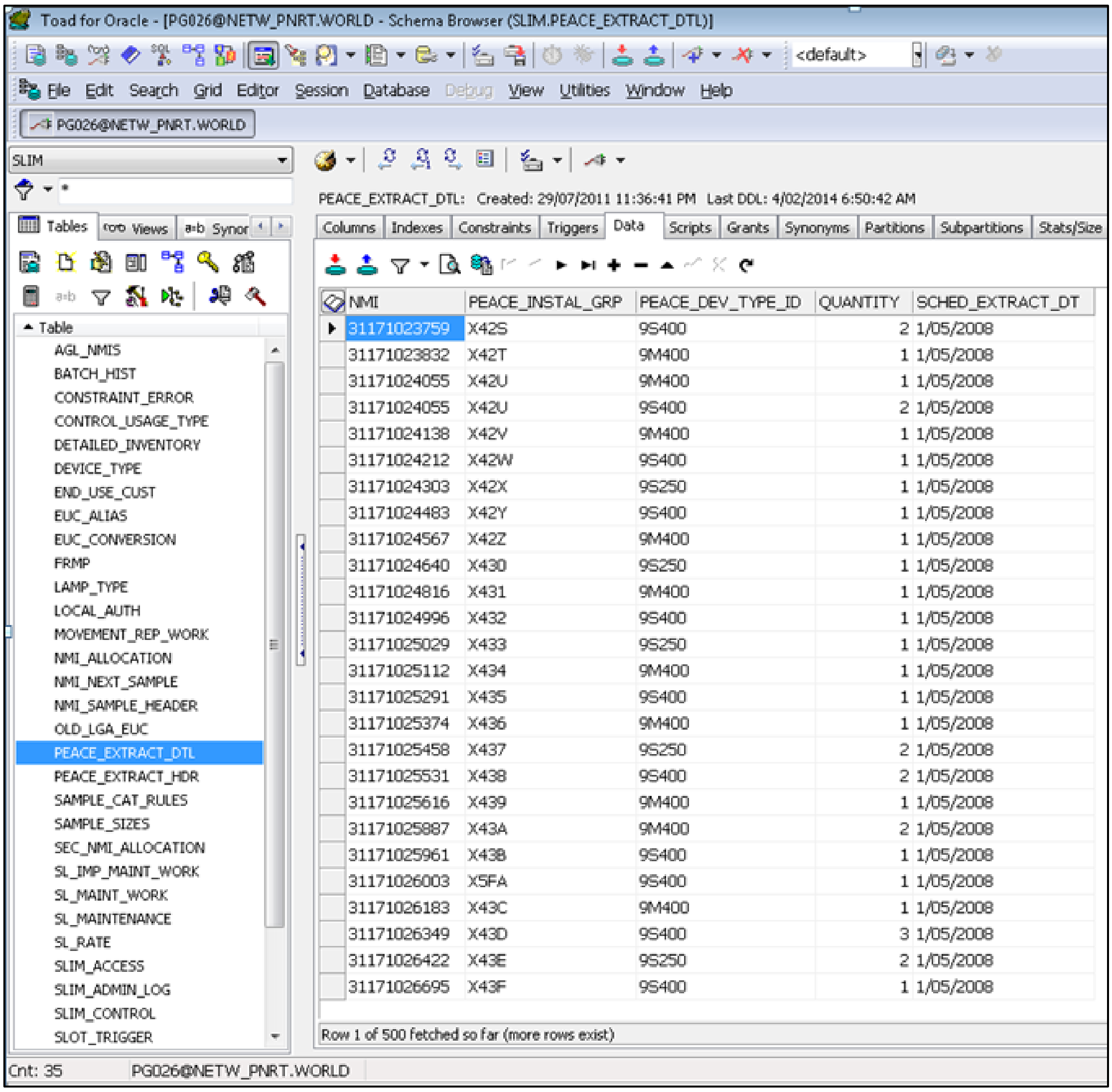
Clause 17.6 of the CA RIN states that Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER. The Reset RIN does not specify this requirement. However, for the purposes of Regulatory Template 4.1:

- Energex included all Rate 1 public lights on the basis that they are supplied, installed, owned and maintained by Energex.
- Energex included Rate 2 public lights to the extent that they are funded by the customer with cash. Rate 2 public lights that are physically gifted to Energex (typically as part of subdivisions) have been excluded.
- All Rate 3 public lights have been excluded on the basis that they are supplied, installed, owned and maintained by the Public Body.

1.3.2 Approach

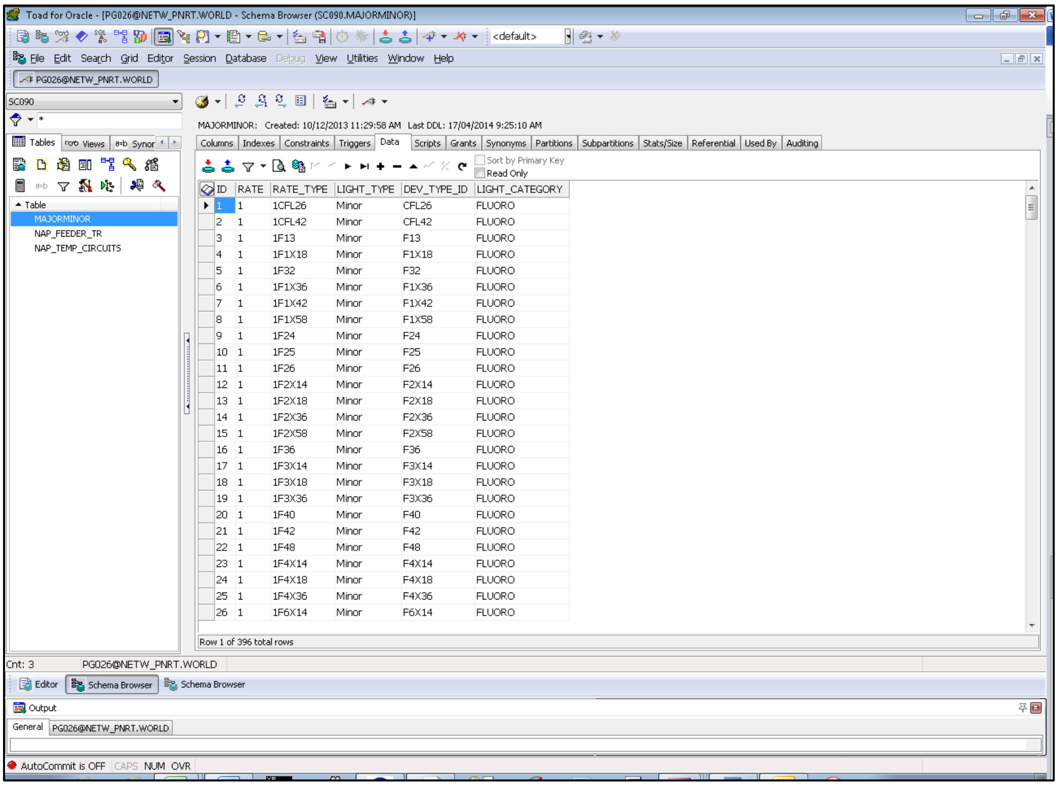
A report was extracted from both the SLIM database and the Oracle database to generate all the data required.

- SLIM.PEACE_EXTRACT-DTL is a SLIM (Streetlight Inventory Manager) table, located in the SLIM schema, containing light types and numbers for all the streetlight NMI's billed through the Peace billing system. The table provides a snapshot of the number of lights held in NFM and SLIM at the 1st day of each month. Streetlight NMI's are billed monthly and the numbers captured in this table are indicative of the number of lights to be billed as at the end of the previous month. A screenshot of the report is provided below.



NMI	PEACE_INSTAL_GRP	PEACE_DEV_TYPE_ID	QUANTITY	SCHED_EXTRACT_DT
31171023759	X42S	9S400	2	1/05/2008
31171023832	X42T	9M400	1	1/05/2008
31171024055	X42U	9M400	1	1/05/2008
31171024055	X42U	9S400	2	1/05/2008
31171024138	X42V	9M400	1	1/05/2008
31171024212	X42W	9S400	1	1/05/2008
31171024303	X42X	9S250	1	1/05/2008
31171024483	X42Y	9S400	1	1/05/2008
31171024567	X42Z	9M400	1	1/05/2008
31171024640	X430	9S250	1	1/05/2008
31171024816	X431	9M400	1	1/05/2008
31171024996	X432	9S400	1	1/05/2008
31171025029	X433	9S250	1	1/05/2008
31171025112	X434	9M400	1	1/05/2008
31171025291	X435	9S400	1	1/05/2008
31171025374	X436	9M400	1	1/05/2008
31171025458	X437	9S250	2	1/05/2008
31171025531	X438	9S400	2	1/05/2008
31171025616	X439	9M400	1	1/05/2008
31171025887	X43A	9M400	2	1/05/2008
31171025961	X43B	9S400	1	1/05/2008
31171026003	X5FA	9S400	1	1/05/2008
31171026183	X43C	9M400	1	1/05/2008
31171026349	X43D	9S400	3	1/05/2008
31171026422	X43E	9S250	2	1/05/2008
31171026695	X43F	9S400	1	1/05/2008

- SC090.MAJORMINOR is a local table created to identify what constitutes a Major or Minor type of light. The data in this table is in accordance with Australian Standard AS/NZ 1158. A screenshot of the report is provided below.



ID	RATE	RATE_TYPE	LIGHT_TYPE	DEV_TYPE_ID	LIGHT_CATEGORY
1	1	1CFL26	Minor	CFL26	FLUORO
2	1	1CFL42	Minor	CFL42	FLUORO
3	1	1F13	Minor	F13	FLUORO
4	1	1F1X18	Minor	F1X18	FLUORO
5	1	1F32	Minor	F32	FLUORO
6	1	1F1X36	Minor	F1X36	FLUORO
7	1	1F1X42	Minor	F1X42	FLUORO
8	1	1F1X58	Minor	F1X58	FLUORO
9	1	1F24	Minor	F24	FLUORO
10	1	1F25	Minor	F25	FLUORO
11	1	1F26	Minor	F26	FLUORO
12	1	1F2X14	Minor	F2X14	FLUORO
13	1	1F2X18	Minor	F2X18	FLUORO
14	1	1F2X36	Minor	F2X36	FLUORO
15	1	1F2X58	Minor	F2X58	FLUORO
16	1	1F36	Minor	F36	FLUORO
17	1	1F3X14	Minor	F3X14	FLUORO
18	1	1F3X18	Minor	F3X18	FLUORO
19	1	1F3X36	Minor	F3X36	FLUORO
20	1	1F40	Minor	F40	FLUORO
21	1	1F42	Minor	F42	FLUORO
22	1	1F48	Minor	F48	FLUORO
23	1	1F4X14	Minor	F4X14	FLUORO
24	1	1F4X18	Minor	F4X18	FLUORO
25	1	1F4X36	Minor	F4X36	FLUORO
26	1	1F6X14	Minor	F6X14	FLUORO

- These two tables were then joined in the TOAD SQL – 'RIN – Rate 1 – 2012-2013.sql' to provide the volume of Rate 1 streetlights broken down by streetlight category and by Major and Minor categories for the year 2013-14.

1.4 Estimated Information

Only Actual Information was supplied in RIN Table 4.1.1.

2 BoP 4.1.2 – Public Lighting – Descriptor Metrics Annually

The AER requires Energex to provide the following information relating to RIN Table 4.1.2:

For each year between the period 2009-10 and 2013-14:

- **The volume of major road lights installed, replaced and maintained**
- **The volume of minor roads lights installed, replaced and maintained**
- **The number of poles installed, replaced and maintained**
- **The total cost of lights installed, replaced and maintained**
- **The mean days to rectify / replace public lighting assets**
- **The volume of GSL breaches**
- **The value GSL payments**
- **The volume of customer complaints**

Estimated Information was provided for the following variables:

- **Number of poles for all years for light installation**
- **Total cost for 2011/12 to 2013/14 for light installation**
- **Major and minor road light installation volumes for light replacement**
- **Number of poles for 2011/12 for light replacement**
- **Total cost for 2011/12 for light replacement**
- **Number of poles for all years for light maintenance**
- **Mean days to rectify/replace assets**

All other information is Actual Information.

These variables are a part of Regulatory Template 4.1 – Public Lighting.

2.1 Consistency with Reset RIN Requirements

Table 2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 2.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The CA RIN instructed that Energex was not required to distinguish expenditure for public lighting services between standard or alternative control services in Regulatory Template 4.1.	This requirement was taken into account in preparing Reset RIN Regulatory Template 4.1. For details refer to section 2.3.
The CA RIN instructed that Energex was not required to distinguish expenditure for public lighting services as either capex or opex in	This requirement was taken into account in

Regulatory Template 4.1.	preparing Reset RIN Regulatory Template 4.1. For details refer to section 2.3.
The CA RIN instructed that Energex must report expenditure data as a gross amount, by not subtracting customer contributions from expenditure data.	This requirement was taken into account in preparing Reset RIN Regulatory Template 4.1. For details refer to section 2.3.
The CA RIN instructed that Energex must report data for non-contestable, regulated public lighting services. This includes work performed by third parties on behalf of Energex.	This requirement was taken into account in preparing Reset RIN Regulatory Template 4.1. For details refer to section 2.3.
The CA RIN instructed that Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER.	This requirement was taken into account in preparing Reset RIN Regulatory Template 4.1. For details refer to section 2.3.
The CA RIN instructed that Energex was not required to report data in respect of GSLs, where a GSL scheme does not exist for a public lighting service.	This requirement was taken into account in preparing Reset RIN Regulatory Template 4.1. For details refer to section 2.3.

Estimated Information was provided for the following variables:

- Number of poles for all years for light installation;
- Total cost for 2011/12 to 2013/14 for light installation;
- Major and minor road light installation volumes for light replacement;
- Number of poles for 2011/12 for light replacement;
- Total cost for 2011/12 for light replacement;
- Number of poles for all years for light maintenance; and
- Mean days to rectify/replace assets.

All other figures are Actual Information.

2.2 Sources

Table 2.2 below sets out the sources from which Energex obtained the required information.

Table 2.2: Information sources

Variable	Source
The volume of major road lights installed, replaced and maintained	NFM, SLIM, Oracle
The volume of minor roads lights installed, replaced and maintained	NFM, SLIM, Oracle
The number of poles installed, replaced and maintained	NFM, Ellipse
The total cost of lights installed, replaced and maintained	EPM, Ellipse, Corvu
The mean days to rectify / replace public lighting assets	Energex "Form 242"
The volume of GSL breaches	N/A
The value GSL payments	N/A
The volume of customer complaints	FROG, Cherwell

2.3 Methodology

2.3.1 Assumptions

General assumptions

- Energex assumed that all instructions provided in the CA RIN were to be applied to the Reset RIN.
- There are three categories of public lights in Energex's network:

- – Rate 1 – Public Lighting supplied, installed, owned and maintained by Energex;
  – Rate 2 - Public Lighting for which all supply and installation costs are funded by the Developer or Public Body and then ownership is vested to Energex on completion of the installation. Or where design and construction services are requested to be undertaken by Energex, the supply and installation costs are funded by the Public Body and the lighting installation is supplied, installed, owned and maintained by Energex. In both cases, Energex assumes responsibility for maintenance of the installation; and
  – Rate 3 – Public Lighting supplied, installed, owned and maintained by the Public Body.

- Clause 17.6 of the CA RIN states that Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER. The Reset RIN does not specify this requirement. However, for the purposes of Regulatory Template 4.1:
  – Energex has included all Rate 1 public lights on the basis that they are supplied, installed, owned and maintained by Energex.
  – Energex has included Rate 2 public lights to the extent that they are funded by the customer with cash. Rate 2 public lights that are physically gifted to Energex (typically as part of subdivisions) have been excluded.
  – All Rate 3 public lights have been excluded on the basis that they are supplied, installed, owned and maintained by the Public Body.

Number of poles installed

- It was assumed that any light installed on a wood pole bracket did not involve installation of a dedicated street light pole as this would be a very small population of poles and the figures are not discernible from other wood poles in Energex's asset records.

Customer Complaints

- Complaints categorised as 'street lighting' relate to customer dissatisfaction with the establishment or maintenance of street lighting (I.e. pole placement, lights not working or brightness of lights).

2.3.2 Approach

Light Installation – volume of works and expenditure

Major and minor road light installation volume

1) To obtain volumes for installations, an SQL query was run through Oracle, utilising various tables from the NFM and SLIM schemas. The query returned the following attributes, based on a 'Movement Status' of added lights (a proxy for installations):

a. Date;

b. Works Order Number;

c. User Ref Id (site ID);

d. Slot_Sun (unique record attached to each streetlight slot);

e. Light Type;

f. Light Rating;

g. Major/Minor status; and

h. Light Category.

2) This query returned all Rate 1 and Rate 2 public lights installed on an annual basis.

3) As noted earlier, gifted public lights are excluded from Regulatory Template 4.1. Gifted public lights were identified as Rate 2 projects approved through Energex's Subdivisions group. These projects were identified as those which had an 'S' qualifier at the beginning of the work order number.

4) From here, the dataset was saved as an Excel file and the Subdivisions Works Orders were removed, leaving all Non-Contributed (Rate 1) and Contributed lights (Rate 2) without the gifted lights.

5) The process was run for each of the financial years between 2009/10 and 2013/14 and each annual dataset was copied to a separate spreadsheet and pivot tables were created, filtering the results into Major and Minor light installations.

6) The total volume of public lighting installed was established by summing the number of public lights for Major and Minor for each financial year.

Number of poles installed

1) For all new lights installed annually between 2009/10 and 2013/14 (volume calculated above), the total number of new lights installed was multiplied by the percentage of the steel pole outreaches issued from Procurement and Supply (relative to the total population of all outreaches issued from stores). This provided an estimated value for the number of public light sites where it was assumed a new pole was installed. This calculation was performed separately for major and minor roads and summed together to produce a value for total poles installed.

2) It was assumed that any light installed on a wood pole bracket did not involve installation of a dedicated street light pole, as this would be a very small population of poles and the figures are not discernible from other wood poles in Energex's asset records. All new street light installations on steel brackets were assumed to require a new steel pole to be installed on a one-to-one basis.

3) While Energex was able to identify the total number of additional new Rate1 or 2 major and minor streetlights added to the billing records each year, this does not identify those new streetlights installed on an existing distribution pole or requiring a new dedicated streetlight pole. Given the historically low volume of streetlights

mounted on new wood poles, it was assumed that the percentage split between steel/wood minor and steel/wood major brackets issued from Energex's Materials Distribution Centre (DC), would be a good indicator of the number of new minor and major streetlights installed on correspondingly new dedicated (steel) streetlight poles. For this purpose and noting that both Nostalgia and Avenue (decorative) luminaires are mounted on their integral outreaches (not included as a separate outreach in the minor road outreach volumes issued from stores, the number of Nostalgia and Avenue luminaires issued from the DC were added to the corresponding volume of minor (conventional) steel outreaches, so as to better reflect the true steel/wood minor bracket volume split.

Total cost

1) A report was run from Mincom Ellipse Reporting which listed all street lighting projects that incurred expenditure between the years 2009/10 and 2012/13 under the following financial activity codes:

Activity Code	Description
C2560	CWDA Public Lighting
C3560	Street Lighting

2) For 2013/14 the list of projects that incurred expenditure in 2013/14 was taken from the EPM Report POW010. The list of projects included is based on the above activities and adjusted for projects split between asset categories based on the percentage allocated to Property Units in the POW010.

3) These reports detailed all expenses and quantities booked against street lighting projects (both installations and replacements) over the five year period.

4) From this data set, a number of adjustments were made to exclude gifted assets and items relating to streetlight mains recovery projects.

5) Gifted assets were excluded in accordance with clause 17.6 of the CA RIN by removing projects with any transaction in expense code 6270 (Capital Contributions Non-Cash Expenses).

6) Street lighting mains recovery projects were excluded from the data set on the basis that this work is the recovery of assets. Expense line items relating to street lighting mains recovery projects were identified by project description and removed from the data set.

7) Cost data from each expense line item was then aggregated to provide the total cost of street lighting projects for each financial year.

8) For 2011/12 the total cost for installations is Estimated Information as the costs of replacement were subtracted from the total cost, leaving the remaining costs to be

attributed to installations. The replacement cost for 2011/12 year is Estimated Information as it is based on the average of 2008/09, 2009/10, 2010/11, and 2012/13. Replacement data for this year was not available.

9) For 2012/13 and 2013/14 the street lighting financial activities included both installation and replacement. The cost attributed to installation is the remaining costs after the known cost of replacement was subtracted. Considering only the replacement costs are certain actual costs, the remaining costs attributed to installations is considered an estimate.

Light Replacement - volume of works and expenditure

Major and minor road light replacement volume

1) Projects relating to public light replacements are not explicitly identified in NFM. In most cases, where a streetlight was replaced, the event log in NFM will show a 'Removal' and an 'Install'. However, this information alone does not provide a true indication of street light replacements.

2) The approach adopted by Energex to derive an estimate for light replacements focussed on analysing two variables:
    a. The volume of lights issued from the Procurement and Supply division
    b. The volume of lights installed in the network.

3) The difference between these two variables was used as proxy for replacements volumes. This was considered a reasonable assumption on the basis that street lighting projects contain two activities – installations and replacements.

Specifically, this process involved the following steps:

1) A report was extracted from Ellipse which provided a list of all streetlights issued by Procurement and Supply between the period 2009/10 and 2013/14. This report provided all Rate 1 and Rate 2 public lights issued by Procurement and Supply, representing volumes for both replacement and installation projects.

2) The data was then separated by financial year and filtered between Major and Minor light types. Rate 2 public lights relating to subdivisions were excluded from the data (identified by work order).

3) The total volume of public lighting for installations and replacements was established by summing the number of public lights issued by Procurement for Major and Minor light types for each financial year.

4) A list of public light installation volumes was then obtained (the same report that was prepared for light installations) which provided the volume of all public lights installed in the network for Rate 1 and 2 categories (excluding gifted assets) by Major and Minor light types for each financial year.

5) Replacement volumes were then derived by subtracting the installation volumes obtained in Step 4 from the installation and replacement volumes obtained in Step 3. This provided replacement volumes for Major and Minor light types for each year between 2009/10 and 2013/14.

Number of poles replaced

1) The volume of poles replaced was obtained by extracting data for actual pole replacement works undertaken under projects for NAMP line SL04 (or equivalent project code). Data for 2011/12 was not available; therefore an average of the years 2008/09, 2009/10, 2010/11 and 2012/13 was used for the 2011/12 year. An average of the 4 years is valid on the basis that pole replacement volumes are reasonably consistent year-on-year.

Total cost

1) Costs for street light replacements was derived from NAMP line SL04 - SL - Replace Unserviceable Pole. For the financial years 2009/10 and 2010/11 these costs were captured in activity C2545 – CWDA Pole Reinstatement. As activity C2545 is reported in the repex Regulatory Template 2.2, the costs associated with NAMP line SL04 have been removed from repex, and included in public lighting Regulatory Template for the total cost of light replacement.

2) The replacement cost for 2011/12 year is an estimate based on the average of 2008/09, 2009/10, 2010/11, 2012/13, as replacement data for this year was not available. An average of the 4 years is valid on the basis that pole replacement volumes are reasonably consistent year-on-year.

3) The costs for 2012/13 and 2013/14 were captured in activity C3560 – Street Lighting under NAMP line SL04. The costs for NAMP line SL04 have been subtracted from the total cost of C3560 (reported in the total cost for light installation).

Light Maintenance – expenditure and volume of works

Major and minor road light maintenance volume

1) The light maintenance volumes represent the actual number of luminaires maintained as part of the street light maintenance contract. This contract constitutes the bulk of the maintenance work on lights in the Energex network. The volumes for major road luminaires and minor road luminaires were extracted directly from the maintenance contract. Maintenance activities included the actual cost for luminaire maintenance (excluding luminaire replacement costs), streetlight circuit maintenance costs and streetlight patrol costs.

2) It is important to note that activities relating to the maintenance of gifted assets were not excluded from the data as these assets could not be identified in the maintenance contract data.

Number of poles maintained

1) The number of poles maintained has not been provided as Energex's pole maintenance contract does not distinguish between poles for street lights and poles for distribution lines.

2) It should be noted that Energex's current standard for the installation and replacement of street lights poles requires the installation of Base Plate Mounted (BPM) poles, which generally require no maintenance. At present approximately 2/3 of the population of dedicated street light poles are BPMs.

Total Cost

1) A report was run from Mincom Ellipse Reporting which listed all street lighting projects that formed part of the maintenance works between the years 2009/10 and 2013/14 under the following financial activity code:

Activity Code	Description
41600	Street Lighting

2) This report detailed all expenses and quantities booked against street lighting maintenance projects over the five year period. Cost data from each expense line item was then aggregated to provide the total maintenance cost of street lighting projects for each financial year. It is important to note that costs relating to maintenance of gifted assets were not excluded from the cost data as these assets could not be identified in the Ellipse report.

Quality of Supply

Mean days to rectify / replace assets

Mean days to rectify/replace assets is estimated data. In order to provide an understanding of the approach used to determine the mean days to rectify / replace assets, it is first necessary to step out the process used by Energex to collect the data.

1) A "Street Lighting Spot Replacement, Maintenance and Repair Sheet" (Form 242) is used by streetlight patrol officers to identify individual lights and streetlight circuits that are faulty. This form details the streetlight site number, location of the streetlight, the fault observed and the date of the patrol. One form can be used to record up to seven lights needing repair.

2) After each patrol, a copy of Form 242 is provided to Energex to record the date of the patrol on a spreadsheet. A copy of the form is also provided to the streetlight repairer. Once all the streetlight repairs are complete, the repairer returns the form back to Energex, detailing the date that all of the repairs were complete. A copy of the completed form is returned to Energex to record the completion date of the repairs. The patrol date is then subtracted from the repair date to get the number of days taken to repair the lights on the form.

3) Energex analysed the data inputted from each Form 242 for each year between 2009/10 and 2013/14, and calculated the average time taken to rectify public lighting assets for each financial year.

It is important to note that the completion date on each Form 242 represents the date of the final repair job. As there are up to seven lights on each form, there can be a substantial variation between the time taken to repair the first light and the time taken to repair the seventh light. This means that the values inputted into Regulatory Template 4.1 will tend to overstate the time taken to rectify / replace streetlights.

Volume of customer complaints

1) Complaint data is derived from a feedback report which extracts information from the Feedback Register for Organisational Growth (FROG) system (for volumes in 2009/10 to 2010/11) and the Cherwell system (for volume in 2011/12 onwards) and encompasses all complaints received to Energex (that is, via phone, letter or email). The report details the date the complaint was received and is categorised by the Customer Relations team using the systems feedback structure.

2) Monthly reports were collated for each financial year and the data was filtered to show the complaints categorised as “street lighting”. The total volume of complaints relating to street lighting was established by summing the number of complaints in this category for each financial year.

2.4 Estimated Information

The following figures are Estimated Information:

- Number of poles for all years for light installation;
- Total cost for 2011/12 to 2013/14 for light installation;
- Major and minor road light installation volumes for light replacement;
- Number of poles for 2011/12 for light replacement;
- Total cost for 2011/12 for light replacement;
- Number of poles for all years for light maintenance; and
- Mean days to rectify/replace assets.

2.4.1 Justification for Estimated Information

- Energex does not capture costs or was unable to quantity data for the variables listed above. As such, Energex was required to prepare Estimated Information for these variables.

2.4.2 Basis for Estimated Information

- Each of the variables that were estimated has been determined based on advice and assumptions made by subject matter experts who have daily exposure to public lighting issues. For full details of the estimation process, refer to the approach section above.

3 BoP 4.1.3 – Public Lighting – Cost Metrics

The AER requires Energex to provide the following information relating to RIN Table 4.1.3:

For each year between the period 2009/10 and 2013-/14, the average unit cost of each light type:

- **Installed on major and minor roads**
- **Replaced on major and minor roads**
- **Maintained on major and minor roads**

Values for installed assets, replaced assets and maintained assets are Estimated Information.

These variables are a part of Regulatory Template 4.1 – Public Lighting.

3.1 Consistency with Reset RIN Requirements

Table 3.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The CA RIN instructed that Energex was not required to distinguish expenditure for public lighting services between standard or alternative control services in Regulatory Template 4.1.	This requirement was taken into account in preparing Reset RIN Regulatory Template 4.1. For details refer to section 3.3.
The CA RIN instructed that Energex was not required to distinguish expenditure for public lighting services as either capex or opex in Regulatory Template 4.1.	This requirement was taken into account in preparing Reset RIN Regulatory Template 4.1. For details refer to section 3.3.
The CA RIN instructed that Energex must report expenditure data as a gross amount, by not subtracting customer contributions from expenditure data.	This requirement was taken into account in preparing Reset RIN Regulatory Template 4.1. For details refer to section 3.3.

Requirements (instructions and definitions)	Consistency with requirements
The CA RIN instructed that Energex must report data for non-contestable, regulated public lighting services. This includes work performed by third parties on behalf of Energex.	This requirement was taken into account in preparing Reset RIN Regulatory Template 4.1. For details refer to section 3.3.
The CA RIN instructed that Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER.	This requirement was taken into account in preparing Reset RIN Regulatory Template 4.1. For details refer to section 3.3.
The CA RIN instructed that in the basis of preparation, Energex must explain how the average unit cost for public lighting services was estimated.	This requirement has been addressed in preparing Regulatory Template 4.1. For details refer to section 3.3.

Estimated Information was provided for all variables in RIN Table 4.1.3.

3.2 Sources

Table 3.2 below sets out the sources from which Energex obtained the required information.

Table 3.2: Information sources

Variable	Source
The average unit cost of lights installed on major and minor roads	Corporate Ellipse estimation module
The average unit cost of lights replaced on major and minor roads	Corporate Ellipse estimation module
The average unit cost of lights maintained on major and minor roads	Street light maintenance contract

3.3 Methodology

3.3.1 Assumptions

General assumptions

- Energex assumed that all instructions provided in the CA RIN were to be applied to the Reset RIN.
- There are three categories of public lights in Energex's network:
  - Rate 1 – Public Lighting supplied, installed, owned and maintained by Energex;
  - Rate 2 - Public Lighting for which all supply and installation costs are funded by the Developer or Public Body and then ownership is vested to Energex on completion of the installation. Or where design and construction services are requested to be undertaken by Energex, the supply and installation costs are funded by the Public Body and the lighting installation is supplied, installed, owned and maintained by Energex. In both cases, Energex assumes responsibility for maintenance of the installation; and
  - Rate 3 – Public Lighting supplied, installed, owned and maintained by the Public Body.
- Clause 17.6 of the CA RIN states that Energex must not report data in relation to gifted assets, negotiated public lighting services or public lighting services which have been classified as contestable by the AER. The Reset RIN does not specify this requirement. However, for the purposes of Regulatory Template 4.1:
  - Energex has included all Rate 1 public lights on the basis that they are supplied, installed, owned and maintained by Energex.
  - Energex has included Rate 2 public lights to the extent that they are funded by the customer with cash. Rate 2 public lights that are physically gifted to Energex (typically as part of subdivisions) have been excluded.
  - All Rate 3 public lights have been excluded on the basis that they are supplied, installed, owned and maintained by the Public Body.

Average unit cost of installation

- Variation in the installation costs of differing lamp types is negligible in comparison with the average installation cost of Energex's standard street light constructions. On this basis, the information provided in Table 4.1.3 is based on Energex's estimated cost of standard street light constructions, which are lamp type agnostic. At present, Energex has 5 types of standard constructions for public lighting, namely:
  - Wood Pole Major – the estimated unit cost assumes the wood pole exists and low voltage supply is available (i.e., average unit cost data does not include the cost of installing a pole or provision of supply);

- Steel Overhead Major – the estimated unit cost includes installation of a new steel pole and provision of a 40 metre span of overhead service;
- Underground Major – the estimated unit cost includes installation of a new steel pole and provision of a 30 metre length of underground supply;
- Wood Pole Minor – the estimated unit cost assumes the wood pole exists and low voltage supply is available (i.e., average unit cost data does not include the cost of installing a wood pole or provision of supply); and
- Steel Underground Decorative Minor– the estimated unit cost includes the installation of a new decorative steel pole and provision of a 5 metre length of underground supply.

- All costs for the street light constructions above were estimated at 2013/14 cost rates. These costs were then de-escalated by CPI to derive an estimate for each year between the period 2009/10 and 2012/13.

Average unit cost of replacement

- The light types provided in Table 4.1.3 for replacements represent the standard luminaires during the period. These include the following:
  - High Pressure Sodium Major 150W;
  - Mercury Vapour Minor 50W (for period 2009-10 to 2012-13), changed to 32CFL for 2013-14; and
  - High Pressure Sodium Minor 70W.
- The differential in luminaire costs for different sizes of the same type of luminaire (e.g. High Pressure Sodium 150W and High Pressure Sodium 250W) was assessed as negligible.
- Significantly more expensive Pedestrian Crossing, High Mast and Bulkhead and Decorative luminaire types have not been considered due to their relatively low volumes in comparison with the standard luminaires.
- The average unit cost data included the estimated cost of supply and replacement of a luminaire, lamp and photoelectric cell.

Average unit cost of maintenance

- Maintenance on the street light network only distinguishes by categories of mounting height, not by light type and size. On this basis, Energex has estimated the average unit cost of maintenance by major road types and minor road types.
- Energex has determined the cost apportionment between major and minor road type categories based on the population of street lights at the end of the year for major and minor road streetlights. The estimated unit cost data is comprised of the following costs:

- Actual cost for luminaire maintenance (excluding luminaire replacement costs);
- Actual Streetlight circuit maintenance costs; and
- Actual Streetlight patrol costs.

3.3.2 Approach

Average unit cost of installation

- The average unit cost of street light installations was estimated for the 5 types of standard constructions:
  - Wood Pole Major – as described above, the estimated unit cost assumes the wood pole exists and low voltage supply is available. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 92431 (version 5).
  - Steel Overhead Major – as described above, the estimated unit cost includes installation of a new steel pole and provision of a 40 metre span of overhead service. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 92434 (version 5).
  - Underground Major – as described above, the estimated unit cost includes installation of a new steel pole and provision of a 30 metre length of underground supply. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 92435 (version 5).
  - Wood Pole Minor – as described above, the estimated unit cost assumes the wood pole exists and low voltage supply is available. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 92430 (version 7).
  - Steel Underground Decorative Minor– as described above, the estimated unit cost includes the installation of a new decorative steel pole and provision of a 5 metre length of underground supply. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 92433 (version 7).

Average unit cost of replacement

- The average unit cost of street light replacements was estimated for the 3 types of luminaires (as identified in the assumptions section above). The methods for calculating the estimated unit costs are outlined below:
  - High Pressure Sodium Major 150W – the estimated unit cost includes the supply and replacement of a luminaire, lamp and photoelectric cell. This unit

cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 424075 (version 02).

  – Mercury Vapour Minor 50W – For the 2009-10 to 2012-13 periods the estimated unit cost includes the supply and replacement of a luminaire, lamp and photoelectric cell. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 424068 (version 02). For the 2013-14 periods, the estimated unit cost includes the supply and replacement of a 32W Compact Fluorescent (CFL) luminaire, lamp and photoelectric cell. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 424068 (version 03). This estimate was prepared during 2014-15, and was de-escalated by 2.93% to determine the cost for 2013-14.
  – High Pressure Sodium Minor 70W – the estimated unit cost includes the supply and replacement of a luminaire, lamp and photoelectric cell. This unit cost was calculated using Energex's corporate Ellipse estimation module, which includes the direct costs for labour, materials and contracted services, Ellipse estimate reference number 424071 (version 02).

- The values calculated in the Estimated Information above were adjusted to present the figures in 2012/13 terms, as the contracted services portion of the estimate had changed by other than CPI from 2013/14. The value for each type of luminaire was deescalated by CPI to derive an estimate for each year between the period 2009/10 and 2012/13.

Average unit cost of maintenance

- The unit cost data of maintenance is comprised of the following:
  – Actual cost for luminaire maintenance (excluding luminaire replacement costs);
  – Actual Streetlight circuit maintenance costs; and
  – Actual Streetlight patrol costs.
- The unit cost for each year for major and minor road streetlights was estimated by dividing the total cost for each year by the population of major and minor street lights at the end of the year.
- The costs for these activities were sourced from Energex's streetlight maintenance contract for each year between 2009/10 and 2013/14, separated by major and minor road types. As noted above in the assumptions section, Energex has determined the cost apportionment between major and minor road type categories based on the proportion of the population of major and minor road luminaires for each financial year.

3.4 Estimated Information

- Estimated Information was provided for all variables in RIN Table 4.1.3.

3.4.1 Justification for Estimated Information

- Energex does not capture costs data for the variables in RIN Table 4.1.3. As such Estimated Information was provided for these variables.

3.4.2 Basis for Estimated Information

- Each of the figures that were estimated has been determined based on advice and assumptions made by subject matter experts who have daily exposure to public lighting issues. For full details of the estimation process, refer to the approach given in the section above.

3.5 Explanatory notes

- There are a number of variables that can affect the volumes/costs:
  - Heavy storm activity in a particular year;
  - Catastrophic weather events e.g. floods which have an ongoing affect, causing failures for many months afterwards;
  - Premature failure of components e.g. batches of faulty PE cells; and
  - Life cycle failures of components e.g. 5 year life cycle of certain lamps.
- This is just sample of some of the variables that may occur or be absent that can cause variation year to year.

4 BoP 4.2.1 – Metering

The AER requires Energex to provide the following information relating to Table 4.2.1 – Metering Descriptor Metrics:

For each financial year in 2009/10 to 2013/14, split by meter installation type (i.e. type 4, 5 or 6):

- **Single phase meter population**
- **Multi-phase meter population**
- **Current transformer connected meter population**
- **Direct connect meter population**

The AER requires Energex to provide the following information relating to Table 4.2.2 – Cost Metrics for meter types 4, 5 and 6:

For each financial year in 2009/10 to 2013/14

- **Expenditure cost for the service subcategories defined by the AER**
- **Volumes of in-service meters for the service subcategories defined by the AER, split by meter installation type (i.e. type 4, 5 or 6).**

Actual information was provided for:

- **All meter volumes reported in table 4.2.1**
- **Volumes of meters and labour costs for following service subcategories in table 4.2.2:**
- **Meter Purchase expenditure & volumes**
- **Scheduled Meter Reads expenditure and volume**
- **Special Meter Reads expenditure and volume**
- **Other Metering expenditures**

Estimated information was provided for all other figures in table 4.2.2.

These variables are a part of Regulatory Template 4.2 – Metering.

4.1 Consistency with Reset RIN Requirements

Table 4.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must ensure that the data provided for metering services reconciles to internal planning models used in generating Energex's proposed revenue requirements.	Figures reconcile to internal planning models where appropriate
Energex is not required to distinguish expenditure for *metering services* as either *capex* or *opex* in *regulatory template* 4.2.	No distinction has been made between capex and opex.

Requirements (instructions and definitions)	Consistency with requirements
Energex must report data for metering services classified by the AER as alternative control services. This includes work performed by third parties on behalf of Energex.	All information collected in accordance with the requirement as defined in appendix F for each line items in table 4.2
Energex must not report data in relation to metering services which have been classified as negotiated services or not classified by the AER.	Strict measures were taken not include any information that is not classified by AER definition
Actual Information presented in response to the Notice whose presentation is Materially dependent on information recorded in Energex's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice.	Actual volumes and costs have been used where available, and was reliably accessible during preparation of the report
Estimated Information presented in response to the Notice whose presentation is not Materially dependent on information recorded in Energex's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice.	Estimated volumes and costs have been used where detailed information was limited to specific individual unit
The CA RIN explanatory statement included the following instruction in relation to table 4.2.1: We expect meter numbers to be calculated as the average meter numbers per annum. That is, closing balance of meter numbers plus opening balance of meter numbers, divided by two.	Energex has applied this instruction when completing table 4.2.1 of the Reset RIN and meter numbers have been calculated as the average during the financial year.

Actual information was provided:

- RIN Table 4.2.1:
  - All figures
- Table 4.2.2 - Volumes of meters and labour costs for following service subcategories:
  - Meter Purchase expenditure & volumes
  - Scheduled Meter Reads expenditure and volume

- Special Meter Reads expenditure and volume
- Other Metering expenditures
- Meter Testing volumes and expenditures

Estimated information was provided for all other figures in RIN table 4.2.2.

4.2 Sources

Table 4.2 below sets out the sources from which Energex obtained the required information.

Table 4.2: Information sources

Variable	Source
RIN Table 4.2.1 – Meter Populations	Peace
RIN Table 4.2.2 – Cost Metrics Expenditure	Peace, Ellipse, ACS Quote Mode, Business Objects Reports
RIN Table 4.2.2 – Cost Metrics Volume	Peace, Ellipse, MARS, Business Objects Reports

4.3 Methodology

4.3.1 Assumptions

The following assumptions have been applied to obtain the required information:

- The labour expenditure was adjusted using the average CPI percentage as published by the Australian Bureau of Statistics for each respective financial year;
- With regards to on-site work, different jobs take different times to complete due to changes in travel times or other factors. The effects of different job timings have been ignored and thus the volume of onsite work assumes an average time is taken to complete a normal job; and
- Energex does not have type 4 or type 5 meters in its regulated business and as such no information has been reported against these variables.

4.3.2 Approach

The following approach below was used to obtain the required information:

Table 4.2.1 – Meter Populations

- Meter population figures were collected by running SQL scripts in the Peace Customer Information System (CIS). These were based on the number of meters in-service as at 30th June of each financial year. These scripts also defined each meter by the model to identify which should be included in the poly phase, single phase, CT connected and DC connected categories. There is an overlap of the volume between single phase volume and CT connected volume to meter installation types.

- All metering numbers have been calculated as the average within the financial year. This is the number of meters as at 1 July plus the number as at 30 June divided by two for each respective year.

Table 4.2.2 – Meter Purchase expenditure and volume

- A report was extracted from Ellipse Explorer application ELL00137 on each supplier of metering equipment and exported into excel for each financial year. This report was then filtered to actual metering equipment type by individual stock code, quantity and expenditure without manipulating any values.
- The figures provided are Actual Information in quantity and expenditure as registered in Ellipse.

Table 4.2.2 – Meter Testing expenditure and volume

- The volume and expenditure figures are as stated in the contracts report extracted from Ellipse for contracts CL97, 07037A, 07037B and 10202.
- An extract out of MARS was also exported to consolidate actual volume of testing request for each financial year as specified by AER. There is no material cost included on this line item.

Table 4.2.2 – Meter Investigation expenditure and volume

- The volume and expenditure figures are extracted from the Peace CIS report PCE021 on the basis of the number of service orders being successfully completed on the site relevant to investigation.
- The expenditure figures exclude material cost.

Table 4.2.2 – Scheduled Meter Reads expenditure and volume

- The numbers for scheduled meter reads are based on actual reads reported through business objects reports. These reports extract the figures as collected by the meter readings systems and actual dollars paid to the contractor under the contract rates.

Table 4.2.2 – Special Meter Reads expenditure and volume

- The numbers for special meter reads are based on actual reads reported through business objects reports.
- These reports extract the figures as collected by the meter readings systems and actual dollars paid to the contractor under the contract rates.

Table 4.2.2 – New Meter Installation expenditure and volume

- The volume and expenditure figures were extracted from the Peace CIS report PCE018 on the basis of number of the meters being installed by financial year.
- The expenditure figures include material costs for other metering equipment on the basis of meter type and Peace CIS report PCE021 for load control relay installation. New Meter Installations include meter replacements as all meter replacements result in a new meter being installed.

Table 4.2.2 – Meter Replacement expenditure and volume

- The volume and expenditure figures were extracted from the Peace CIS report PCE021, Ellipse contracts report CL97, 07037A, 07037B, 10202 and MARS MRT information on the basis of number of service orders being successfully completed on the site relevant to each replacement for each financial year.
- The expenditure includes material cost of metering equipment where appropriate. Where the information is sourced from contracts, the values are Actual Information and where the system extracts have been used, the values are Estimate Information.
- Meter replacements are also included in new meter installations expenditure and volumes as all meter replacements are replaced with new meters

Table 4.2.2 – Meter Maintenance expenditure and volume

- The volume and expenditure figures are extracted from the Peace CIS report PCE021 on the basis of number of service orders being successfully completed on site relevant to maintenance as defined by AER for each specified financial year.
- The expenditure figures exclude all material cost.

Table 4.2.2 – Remote Meter Reading expenditure and volume

- Energex does not have type 4 meters in its regulated business and as such values of zero were reported for these variables.

Table 4.2.2 – Remote Meter Reconfiguration expenditure and volume

- Energex does not have type 4 meters in its regulated business and as such values of zero were reported for these variables.

Table 4.2.2 – Other Metering expenditure

- No other metering expenditure has been recorded.
- Appendix E section 19 of the Reset RIN no longer requires Energex to distinguish expenditure for metering services between SCS and ACS and instead implies that all expenditure should be ACS only. Accordingly, Energex has removed Other

Metering capex from the historical information in the Reset RIN, as it relates to SCS capex for current transformers and load control relays.

Table 4.2.2 – IT Infrastructure Opex/Capex

- Energex does not have type 4 meters in its regulated business and as such values of zero were reported for these variables.

Table 4.2.2 – Communications Infrastructure Opex/Capex

- Energex does not have type 4 meters in its regulated business and as such values of zero were reported for these variables.

General – Expenditure calculation (Labour)

- Where reliable information was not available with respects to historical internal labour costs, the labour rate was calculated based on the labour rates for the financial year 2013-14.

- The current year cost rates were then de-escalated using the CPI figures obtained from the ABS back to the respective historical years from 2009-10 to 2012-13.

4.4 Estimated Information

Energex has provided Actual Information tables 4.2.1 and 4.2.2 where available and considered reliable. Where historical data was not available, or considered unreliable, Estimated Information was reported.

4.4.1 Justification for Estimated Information

- Estimation of some historical data was required because the actual data was either not collected by field workers, or not recorded in current reporting systems. Metering work is usually completed as part of a new connection and service installation, and the same field workers do all these tasks and the historical costs were captured for the whole job (all tasks) including travelling to and from the job. Splitting the metering work from the other tasks done at the same time required estimation.

Please note the following with respect to the metering Estimate Information:

- Estimated Information is based on records and information compiled by field staff using systems and processes that were developed and used at a time when the level and accuracy of labour costing detail was not required or was considered secondary to getting the work done efficiently.

- Energex records better information with respect to services provided by external contractors. Where costs have been derived purely from contractor costs the data is considered Actual Information. Where data contains internal labour costs this constitutes Estimated Information.

4.4.2 Basis for Estimated Information

- Energex used their work estimation system and consultations with field workers and their respective supervisors to determine appropriate labour cost estimates for earlier years. Labour costs were de-escalated using the CPI figures from the ABS.

4.5 Explanatory notes

- Floods, storms and changes from electromechanical to electronic meters have resulted in an abnormal distribution of meter purchases over the years. Also changes between refurbishing and purchasing meters have impacted the quantities reported.

- Government initiated solar PV incentive schemes resulted in a substantial increase in meter replacement work, to provide the export data capability needed for the resulting tariff. Other tariff reforms and smart meter / smart grid projects have also resulted in additional meter purchases and labour costs in recent years.

Scheduled meter reads and special meter reads

- An anomaly in 2010 is caused by the change in contract conditions and meter reading rates. The period July 2009 to June 2010 (2010) was the last year of the previous contract and the period July 2010 to June 2011 (2011) was the first year of the new contract. A renegotiation of the rates was based on going back to market and competition between potential contractors.

5 BoP 4.3.1 – Fee-Based Services

The AER requires Energex to provide the following information relating to Table 4.3.1 – Cost Metrics for Fee-Based Services:

- **Expenditure and volumes for all fee-based services listed in Energex's annual tariff proposal for the period 2009/10 to 2013/14 per the classification in the AER's framework and approach paper.**

These variables are a part of worksheet 4.3 – Fee-based Services.

Upgrade of service to three phase is estimated.

Estimated information was provided for:

- **Upgrade of service to three phases**
- **Particular services in the 2010/11 and 2011/12 regulatory years. These services are detailed in the estimates section below.**

All other information provided is Actual.

These variables are a part of Regulatory Template 4.3 – Fee-Based Services.

5.1 Consistency with Reset RIN Requirements

Table 5.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 5.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In responding to this Notice Energex must apply the classification of services in the framework and approach paper for the Previous Regulatory Control Period, the Current Regulatory Control Period and for Forecast Information. a) Note this section 1.1 does not relate to the value of Energex's regulatory asset base prior to 1 July 2015.	Energex has complied with this requirement when completing regulatory template 4.3. For details please refer to Basis of Preparation 0.1 – "Backcasting".
Energex must ensure that the data provided for fee-based services reconciles to internal planning models used in generating Energex's proposed revenue requirements.	Energex has applied this consistency requirement
In the regulatory templates 4.3, Energex must list all the Fee Based services that were listed in the annual tariff proposal of each relevant year.	Energex has applied this consistency requirement
In the basis of preparation, Energex must provide a description of each	Energex has applied this

Requirements (instructions and definitions)	Consistency with requirements
Fee Based service listed in the regulatory templates 4.3. In each services' description, Energex must explain the purpose of each service and detail the activities which comprise each service.	consistency requirement
Energex is not required to distinguish expenditure for Fee Based services between standard or alternative control services in regulatory templates 4.3.	As per the current annual RIN, there is no crossover between the services under standard and alternative control services (ACS). Fee Based Services are ACS only
Energex is not required to distinguish expenditure for Fee Based as either Capex or Opex in regulatory templates 4.3.	Energex has applied this consistency requirement

Estimated Information was provided for:

- Upgrade of service to three phases – this information is backcast to align with the 2015-20 classification of services
- Particular Fee-Based Services expenditure in Regulatory Template 4.3 for 2010/11 and 2011/12. These are specified in the 'Basis for Estimates' section below.

Actual Information was provided for all other values.

5.2 Sources

- Information for 2009/10 to 2012/13 has been obtained from the prior year Category Analysis RIN, however the original sources have been listed below 2013/14 data has been obtained from the annual regulatory accounts and workpapers.
- For upgrade of services to three phase please see backcasting Basis of preparation.

Table 5.2 below sets out the sources from which Energex obtained the required information.

Table 5.2: Information sources

Variable		Source
Expenditure dollar values for fee based services	2009-10	Annual regulatory accounts and workpapers
Volumes for fee based	2009-10	Annual regulatory accounts and workpapers

Variable		Source
services		
Expenditure dollar values for fee based services	2010-11 to 2011-12	Ellipse Profit & Loss Reports Ellipse Detailed Transaction Reports, including details of direct vs overhead costs Total Fee Based Services Opex Costs (including overhead) as per the Audited Annual RIN
Volumes for fee based services	2010-11 to 2012-13	Annual pricing proposal submitted to the Australian Energy Regulator
Expenditure dollar values for fee based services	2012-13 to 2013-14	Audited Annual RIN submitted to the Australian Energy Regulator
Volumes for fee based services	2013-14	MSR246 Peace report

5.3 Methodology

Below is the methodology applied to report the Fee Based Services expenditure and volumes.

5.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Energex has consistently reported direct costs throughout other Regulatory Templates. This means that overhead costs have been excluded from the Fee-Based Services figures reported in Regulatory Templates 4.3;
- Apportionment of certain Fee-Based services (detailed below in section 1.1.3.2) was required to report on certain sub-categories.

5.3.2 Approach

Energex applied the following approach to obtain the required information:

Expenditure Dollar Values

Please note the figures for 2009/10 to 2012/13 were provided in Energex's April 2014 CA RIN submission and information provided in the Reset RIN has been sourced directly from that which has previously been provided. The approach used to obtain these figures for the CA RIN is listed below for your reference.

- 2009/10
  - Alternative Control-equivalent services for the previous Determination period (classified as Excluded Distribution Services from 2007/08 to 2009/10) were not further sub-classified as Fee-Based Services. For CA RIN purposes, Energex determined this sub-classification based on a review of the work papers for the regulatory accounts for the relevant years. In most cases:
    - Business-to-Business (B2B) services provided to retailers have been classified as Fee-Based;
  - Exceptions relate to services which can be both Fee-Based and Quoted, dependant on the nature. For example, simple services for Temporary Connections are Fee-Based whereas complex services are Quoted Services;
  - Service categories match those in the annual Tariff Schedules. As services were not sub-classified as Fee-Based Services, all services in the Tariff Schedule were included in both CA RIN templates 4.3 and 4.4; and
  - Figures reconcile to those reported in the annual regulatory accounts excluding overheads.
- 2010/11
  - The expenditure values for Fee-Based Services for 2010/11 were extracted from Ellipse Detailed Transactions reports;
  - The audited Annual RIN 2010/11 provides the total operational expense including overheads, as per AER requirements. Expenditure values in the CA RIN template 4.3 were adjusted to exclude overheads, which were sourced from the Ellipse Detailed Transaction report; and
  - Energex's financial reports in 2010/11 did not disaggregate to the level required in the CA RIN template 4.3, as this level of reporting commenced in 2012/13. Therefore for the categories in the table below, the total figures for each Energex Financial Category were disaggregated using the percentage distribution for the 2012/13 financial year.

Energex Financial Categories	Regulatory Information Notice Categories	2012-2013 %
Meter Inspect	Meter test	66.13%
Meter Inspect	Meter inspection	33.87%

Energex Financial Categories	Regulatory Information Notice Categories	2012-2013 %
Re-energisation	Re-energisation - business hours	8.19%
Re-energisation	Re-energisation - after hours	2.67%
Re-energisation	Re-energisation (visual) - business hours	75.73%
Re-energisation	Re-energisation (visual) - after hours	13.38%
Re-energisation	Re-energisation non-payment (visual) - business hours	0.02%
Re-energisation	Re-energisation non-payment (visual) - after hours	0.01%
Fee Based Streetlighting	Street light glare screening	71.49%
Fee Based Streetlighting	Replacement of standard luminaries with aero screen units (per street light)	28.51%

- 2011-12
  - Ellipse Profit & Loss Reports and the Ellipse Detailed Transactions reports were used to extract the expenditure requirements for the CA RIN template 4.3;
  - The audited Annual RIN 2011/12 provides the total operational expense including overheads. Expenditure values in the CA RIN template 4.3 were adjusted to exclude overheads, which were sourced from the Ellipse Detailed Transaction report; and
  - Energex's financial reports in 2011/12 did not disaggregate to the level required in the CA RIN template 4.3, as this level of reporting commenced in 2012/13 year. Therefore, for the categories in the table over page, the total figures for each Energex Financial Category were disaggregated as per the percentage distribution for 2012/13.

Energex Financial Categories	Regulatory Information Notice Categories	2012-2013 %
Meter Inspect	Meter test	66.13%
Meter Inspect	Meter inspection	33.87%
Re-energisation	Re-energisation - business hours	8.19%
Re-energisation	Re-energisation - after hours	2.67%
Re-energisation	Re-energisation (visual) - business hours	75.73%
Re-energisation	Re-energisation (visual) - after hours	13.38%
Re-energisation	Re-energisation non-payment (visual) - business hours	0.02%
Re-energisation	Re-energisation non-payment (visual) - after hours	0.01%
Fee Based Streetlighting	Street light glare screening	71.49%
Fee Based Streetlighting	Replacement of standard luminaries with aero screen units (per street light)	28.51%

- 2012/13 – 2013/14
  - The audited Annual RINs for 2012/13 and 2013/14 provided the detailed expenditure figures required for each of these years in Reset RIN template 4.3.

Volume

Please note the figures for 2009/10 to 2012/13 were provided in Energex's April 2014 CA RIN submission and information provided in the Reset RIN has been sourced directly from that which has previously been provided. The approach used to obtain these figures for the CA RIN is listed below for your reference.

- 2009/10
  - The total volumes of services reported equal those in the regulatory accounts each year. The disaggregation of Fee-Based was sourced from the regulatory account work papers;
  - Volumes reported represent the number of services billed to customers; and

- Schedule 8 of the Queensland Electricity Regulation 2006 caps the price of particular services, meaning that Energex cannot charge customers for these services. Accordingly, no volumes have been reported for de-energisations and re-energisations during business hours for these two years.

- 2010/11, 2011/12, 2012/13
  - As information on volumes is no longer required as part of the Annual RINs, all volumes were obtained from the Annual Pricing Proposal submitted to the Australian Energy Regulator.

- 2013/14
  - As information on volumes is no longer required as part of the Annual RINs, all volumes were obtained from the PEACE report MSR246. These volumes represent the number of services performed, including all de-energisations and re-energisations.

5.4 Estimated Information

- Upgrade of service to three phases
- Particular Fee-Based Services expenditure in Regulatory Template 4.3 for 2010/11 and 2011/12. These are specified in the 'Basis for Estimates' section below.

5.4.1 Justification for Estimated Information

- Appendix E section 1.2 of the Reset RIN states that Energex must apply the classification of services in the framework and approach paper for the Previous Regulatory Control Period, the Current Regulatory Control Period and for Forecast Information. Section 1.2(a) notes this section 1.1 does not relate to the value of Energex's regulatory asset base prior to 1 July 2015.
- As upgrades of services to three phases is expected to be reclassified for the forthcoming period it was necessary to backcast the related historical data. This information is therefore considered to be estimated.
- Prior to the 2012/13 years, Energex's financial reports did not disaggregate all services to the level required in RIN Table 4.3.1. Therefore actual percentages for the individual services for 2012/13 were used to allocate the aggregated services to individual services for 2010/11 and 2011/12.

5.4.2 Basis for Estimated Information

- Refer to Backcasting BoP for further information on changes to historical data as a result of changes in service classification for the forthcoming regulatory control period.

- The expenditure figures in Regulatory Template 4.3 Fee-Based Services for the 2010/11 and 2011/12 financial years for the below listed categories were apportioned using the actual percentages from the 2012/13 year.
  - Meter test;
  - Meter inspection;
  - Re-energisation - business hours;
  - Re-energisation - after hours;
  - Re-energisation (visual) - business hours;
  - Re-energisation (visual) - after hours;
  - Re-energisation non-payment (visual) - business hours;
  - Re-energisation non-payment (visual) - after hours;
  - Street light glare screening; and
  - Replacement of standard luminaries with aero screen units (per street light).

5.5 Explanatory notes

- After hours provision of any fee-based service (excluding re-energisations):
  - System limitations do not allow Energex to recognise the expense for after-hours fee based services separately from the business hours expense. This means that after hours provision of fee-based services is not separately quantifiable.
- Overhead service replacement no expenditure 2010/11 and 2011/12:
  - Prior to 2012/13 Energex was conducting an Overhead service lines safety upgrade project. This project was to upgrade any overhead service lines that did not meet current safety standards. Therefore, this fee based service did not obtain any customer requests during the 2010/11 and 2011/12 period.

6 BoP 4.3.1 – Quoted Services

The AER requires Energex to provide the following information relating to Table 4.4.1 – Cost Metrics for Quoted Services:

- **Expenditure and volumes for all quoted services listed in Energex's annual tariff proposal for the period 2009/10 to 2013/14 per the classification in the AER's framework and approach paper.**
- **These variables are a part of worksheet 4.4 – Quoted Services.**
- **Pre-connection services data is estimated**
- **Real estate developments data is estimated**
- **Accreditation of alternative service providers data is estimated**
- **Rearrangement of assets data is estimated**

Remaining data is actual.

These variables are a part of Regulatory Template 4.3 – Quoted Services.

6.1 Consistency with Reset RIN Requirements

Table 6.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 6.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In responding to this Notice Energex must apply the classification of services in the framework and approach paper for the Previous Regulatory Control Period, the Current Regulatory Control Period and for Forecast Information. Note this section 1.1 does not relate to the value of Energex's regulatory asset base prior to 1 July 2015.	Energex has complied with this requirement when completing regulatory template 4.3. For details please refer to Basis of Preparation 0.1 – "Backcasting".
Energex must ensure that the data provided for quoted services reconciles to internal planning models used in generating Energex's proposed revenue requirements.	Energex has applied this consistency requirement
In the regulatory templates 4.4, Energex must list all the Quoted services that were listed in the annual tariff proposal of each relevant year.	Energex has applied this consistency requirement
In the basis of preparation, Energex must provide a description of each Quoted service listed in the regulatory templates 4.4. In each services' description, Energex must explain the purpose of each service and	Energex has applied this consistency requirement

Requirements (instructions and definitions)	Consistency with requirements
detail the activities which comprise each service.	
Energex is not required to distinguish expenditure for Quoted services between standard or alternative control services in regulatory templates 4.4.	As per the current annual RIN, there is no crossover between the services under standard and alternative control services (ACS). Quoted Services are ACS only.
Energex is not required to distinguish expenditure for Quoted services as either Capex or Opex in regulatory templates 4.4.	Energex has applied this consistency requirement

The following data is estimated information as this information is all backcast due as Energex must apply the classification of services in the framework and approach paper:

- Pre-connection services data
- Real estate developments data
- Accreditation of alternative service providers data
- Rearrangement of assets data
- All other information provided is actual information.

6.2 Sources

Information for 2009/10 to 2012/13 has been obtained from the prior year Category Analysis RIN's, however the original sources are listed below. 2013/2014 has been obtained from the annual regulatory accounts and workpapers.

For all backcast data please refer to the backcasting basis of preparation. The backcast items in quoted service are:

- Pre-connection services data
- Real estate developments data
- Accreditation of alternative service providers data
- Rearrangement of assets data

Table 6.2 below sets out the sources from which Energex obtained the required information.

Table 6.2: Information sources

Variable		Source
Expenditure dollar values for quoted services	2009-10	Annual regulatory accounts and workpapers
Volumes for quoted services	2009-10	Annual regulatory accounts and workpapers
Expenditure dollar values for quoted services	2010-11 to 2011-12	Ellipse Profit & Loss Reports Ellipse Detailed Transaction Reports, including details of direct vs overhead costs Total Quoted Services Opex Costs (including overhead) as per the Audited Annual RIN
Volumes for quoted services	2010-11 to 2012-13	Annual pricing proposal submitted to the Australian Energy Regulator
Expenditure dollar values for quoted services	2012-13 to 2013-14	Audited Annual RIN submitted to the Australian Energy Regulator
Volumes for quoted services	2013-14	EPM Report - Quoted Services Volume & Revenue : 128178 : 134034

6.3 Methodology

Below is the methodology applied to report the Quoted Services expenditure and volumes.

6.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Energex has consistently reported direct costs throughout other Regulatory Templates. This means that overhead costs have been excluded from the Quoted Services figures reported in Regulatory Template 4.4;

6.3.2 Approach

Energex applied the following approach to obtain the required information:

Expenditure Dollar Values

Please note the figures for 2009/10 to 2012/13 were provided in Energex's April 2014 CA RIN submission and information provided in the Reset RIN has been sourced directly from that which has previously been provided. The approach used to obtain these figures for the CA RIN is listed below for your reference.

- 2009/10
  - Alternative Control-equivalent services for the previous Determination period (classified as Excluded Distribution Services from 2007/08 to 2009/10) were not further sub-classified Quoted Services. For CA RIN purposes, Energex has determined this sub-classification based on a review of the work papers for the regulatory accounts for the relevant years. In most cases:
    - Price on Application (POA) services and Infrastructure Projects (conducted under State Government infrastructure development initiatives, which are similar in nature to Rearrangement of Network Assets) have been classified as Quoted Services
  - Exceptions relate to services which can be both Fee-Based and Quoted, dependant on the nature. For example, simple services for Temporary Connections are Fee-Based whereas complex services are Quoted Services;
  - Service categories match those in the annual Tariff Schedules. As services were not sub-classified as Quoted Services, all services in the Tariff Schedule were included in both CA RIN Templates 4.3 and 4.4; and
  - Figures reconcile to those reported in the annual regulatory accounts excluding overheads.
- 2010/11
  - The expenditure values for Quoted Services for 2010/11 were extracted from Ellipse Detailed Transactions reports; and
  - The audited Annual RIN 2010/11 provides the total operational expense including overheads, as per AER requirements. Expenditure values in RIN Template 4.4 were adjusted to exclude overheads, which were sourced from the Ellipse Detailed Transaction report.
- 2011/12
  - Ellipse Profit & Loss Reports and the Ellipse Detailed Transactions reports were used to extract the expenditure requirements for RIN Template 4.4; and
  - The audited Annual RIN 2011/12 provides the total operational expense including overheads. Expenditure values in RIN Template 4.4 were adjusted to exclude overheads, which were sourced from the Ellipse Detailed Transaction report.

- 2012/13 and 2013/14
  - The audited Annual RIN for the 2012/13 and 2013/14 regulatory years provided the detailed expenditure figures provided for each of these years in Regulatory Template 4.4.

Volume

Please note the figures for 2009/10 to 2012/13 were provided in Energex's April 2014 CA RIN submission and information provided in the Reset RIN has been sourced directly from that which has previously been provided. The approach used to obtain these figures for the CA RIN is listed below for your reference.

- 2009/10
  - The total volumes of services reported equal those in the regulatory accounts each year. The disaggregation of Quoted Services has been sourced from the regulatory account work papers;
  - Volumes reported represent the number of services billed to customers; and
  - Schedule 8 of the Queensland Electricity Regulation 2006 caps the price of particular services, meaning that Energex cannot charge customers for these services. Accordingly, no volumes have been reported for de-energisations and re-energisations during business hours for these two years.
- 2010/11, 2011/12, 2012/13
  - As information on volumes is no longer required as part of the Annual RINs, all volumes were obtained from the Annual Pricing Proposal submitted to the Australian Energy Regulator;
- 2013/14 Volumes
  - As information on volumes is no longer required as part of the Annual RINs, all volumes were obtained from the EPM Report - Quoted Services Volume & Revenue : 128178 : 134034; and
  - These volumes represent the number of services performed.

6.4 Estimated Information

The following data is estimated information as this information is all backcast due as Energex must apply the classification of services in the framework and approach paper:

- Pre-connection services data
- Real estate developments data
- Accreditation of alternative service providers data
- Rearrangement of assets data

6.4.1 Justification for Estimated Information

- Appendix E section 1.2 of the Reset RIN states that Energex must apply the classification of services in the framework and approach paper for the Previous Regulatory Control Period, the Current Regulatory Control Period and for Forecast Information. Section 1.2(a) notes this section 1.1 does not relate to the value of Energex's regulatory asset base prior to 1 July 2015.

- The above services are expected to be reclassified in the forthcoming period. It was therefore necessary to backcast original data to be compliant with reporting requirements. This information is therefore considered to be estimated.

6.4.2 Basis for Estimated Information

Refer to Backcasting BoP for further information on changes to historical data as a result of changes in service classification for the forthcoming regulatory control period.

6.5 Explanatory notes

Rearrangement of Network Assets

- After consultation with the AER in 2010, major asset rearrangements involving upgrades to the shared network have been classified as SCS capex, with the revenue treated as a capital contribution. Consequently, Rearrangement of Network Assets expenditure in 2012-13 is negative as the result of the reclassification of expenditure for projects originally created as ACS opex, but which needed to be converted to SCS capex upon completion (this conversion process was delayed for projects already in progress, due to technical difficulties). The expenditure for these projects was previously reported as ACS opex as incurred.

- Under Queensland transitional arrangements, these services were previously treated as SCS capex with a capital contribution for the customer-funded portion. This reclassification has been added to the existing line item for Rearrangement of assets within template 4.4. One project in particular contributed to the increase, with approximately $47M reclassified over the four years from 2008/09 to 2011/12 (with $24.4M in 2009/10)

Energy Efficient Streetlights

- Prior to 2012-13 this service was captured under the category for Quoted Services Other Recoverable Works due to the low expenditure.

- The volume for Energy Efficient Street Lights in 2012-13 was not available from the pricing proposal however this service is reported in the annual RIN.

Large Customer Connections

- Energex's accounting treatment for Large Customer Connections is governed by the contracts with the customers. As such, transactions are similar in nature to

SCS capex projects that receive capital contributions. Therefore all Large Customer Connection projects are treated as capex with expenditure recognised as incurred. Revenue cannot be recognised until the asset is fully constructed and energised.

Real estate developments

- Spend reduced was higher in 2009/10 due the regulatory environment. Energex previously contributed materials to subdivision projects, however this ceased from 2010/11.

Energex

Reset RIN

Basis of Preparation

5. Network Information

October 2014

energex

positive energy

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the fast growing region of South East Queensland. Energex provides distribution services to almost 1.4 million connections, delivering electricity to 2.8 million residents and businesses across the region.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Section 5 – Network Information

1 BoP 5.4.1 – Maximum Demand and Utilisation Spatial

The AER requires Energex to provide the following information relating to Table 5.4.1 – Non-Coincident and Coincident Maximum Demand:

For each sub-transmission and zone substation in the network, Energex is required to provide the following information:

- **Substation Rating – Normal Cyclic Rating**
- **Raw Adjusted maximum demand, in MW and MVA**
- **Date and time of maximum demand**
- **Whether maximum demand occurred in winter or summer**
- **10POE Weather adjusted maximum demand, in MW and MVA**
- **50POE Weather adjusted maximum demand, in MW and MVA**

All figures reported are Actual Information.

These variables are a part of Regulatory Template 5.4 – Maximum Demand and Utilisation Spatial.

1.1 Consistency with Reset RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 1.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
In regulatory templates 5.4.1 and 5.4.2 (on regulatory template 5.4), Energex must input maximum demand information for the indicated network segments. a) Energex must insert rows into the regulatory templates for each component of its network belonging to that segment. Energex must note instances where it de-commissions components of its network belonging to that segment in the basis of preparation document(s).	Information on maximum demand was provided in accordance with the template
For the 'Winter/Summer peaking' line item, the Energex is to indicate the season in which the raw maximum demand occurred by entering 'Winter' or 'Summer' as appropriate.	Demonstrated in section 1.3.2 Approach
Where maximum demand in MVA occurred at a different time to	Demonstrated in section

Requirements (instructions and definitions)	Consistency with requirements
maximum demand in MW, Energex must enter maximum demand figures for both measures at the time maximum demand in MW occurred. In such instances, Energex must enter the maximum demand in MVA in the basis of preparation, noting the regulatory year in which it occurred.	1.3.2 Approach
If either the MW or MVA measure is unavailable, calculate the power factor conversion as an approximation based on best engineering estimates.	N/A
If Energex cannot use raw unadjusted maximum demand as the basis for the information it provides in RIN Table 5.4.1, it must describe the methods it employs to populate those tables.	Demonstrated in section 1.3.2 Approach
Energex must input the rating for each element in each network segment. For regulatory templates 5.4.1 and 5.4.2, rating refers to normal cyclic rating. a) Energex must provide the seasonal rating that corresponds to the time of the raw adjusted maximum demand. For example, Energex must provide the summer normal cyclic rating of the network segment if the raw adjusted maximum demand occurred in summer. b) Where Energex does not keep and maintain connection point rating information (for example, where the TNSP owns the assets to which such ratings apply), it may estimate this information or shade the cells black.	Demonstrated in section 1.3.2 Approach
Energex must provide inputs for 'Embedded generation' if it has kept and maintained historical data for embedded generation downstream of the specified network segment and/or if it accounts for such embedded generation in its maximum demand forecast. a) Energex must allocate embedded generation figures to the appropriate element of the network segment under system normal conditions (consistent with the definition of raw adjusted maximum demand). b) Energex must describe the type of embedded generation data it has provided. For example, Energex may state that it has included scheduled, semi-scheduled and non-scheduled embedded generation in the tables for connection points. In this example, we would be able to calculate native demand by adding these figures to the raw adjusted maximum demand figures.	Demonstrated in section 1.3.2 Approach

Requirements (instructions and definitions)	Consistency with requirements
c) If Energex has not kept and maintained historical data for embedded generation downstream of the specified network segment, it may estimate the historical embedded generation data or shade the cells black. For the Regulatory Years including and after 2015 Energex must provide embedded generation data. It must do similarly if it accounts for embedded generation in its system level maximum demand forecast.	
Energex must provide inputs for the appropriate cells if it has calculated historical weather corrected maximum demand. a) Energex must provide a short description of its weather correction process in the basis of preparation document(s). Energex must describe whether the weather corrected maximum demand figures provided are based on raw adjusted maximum demand or raw unadjusted maximum demand or another type of maximum demand figure. b) Where Energex does not calculate weather corrected maximum demand it may estimate the historical weather corrected data or shade the cells black. For Regulatory Years 2015 and thereafter Energex will be required to provide weather corrected maximum demand on an ongoing basis in accordance with best regulatory practice weather correction methodologies.	Demonstrated in section 1.3.2 Approach
Tables requesting system coincident data are referring to the demand at that particular point on the network (e.g. zone substations) at the time of system (or network) peak. a) For example, regulatory template 5.4.2 (on regulatory template 5.4) requests information about the maximum demand on zone substations at the time of system or network peak. b) Conversely, non coincident data is the maximum demand at a particular point on the network (which may not necessarily coincide with the time of system peak). For example, regulatory template 5.4.1 (on regulatory template 5.4) requests information about non-coincident maximum demand at zone substations. In regulatory template 5.4.1 (on regulatory template 5.4), Energex must provide information about the maximum demand at each zone substation in each year, which may not correspond to demand at the time of system peak. c) If Energex does not record and/or maintain spatial maximum demand coincident to the system maximum demand, Energex must provide spatial maximum demand coincident to a higher network segment. Energex must specify the higher network segment to which the lower network segment is coincident to in	Demonstrated in section 1.3.2 Approach

Requirements (instructions and definitions)	Consistency with requirements
the basis of preparation document(s). For example, if Energex does not maintain maximum demand data for zone substations coincident to the system maximum demand, Energex may provide maximum demand data coincident to the connection point. In this example, Energex would specify the relevant connection point in the basis of preparation document(s).	

All figures provided are actual Information.

1.2 Sources

- The SIFT database was used to extract Non-coincident and coincident peak demands for the last five years for each zone and Bulk Supply substation in the Energex area of supply. The date and time of the peak demands were also extracted from the SIFT database.
- The SIFT database is linked to the Energex SCADA networks and extracts the half hour substation directly from this network.
- Temperature data was extracted from five Bureau of Meteorology (BOM) sites across Energex – Amberley, Maroochydore Airport, Brisbane Airport, Archerfield and Coolangatta.
- Embedded generation is metered directly and can be added or deleted from the attached zone substation as required. The embedded generation data is extracted from the Network Load Forecasting (NLF) database.
- The POE adjustment values were extracted from the SIFT database where they exist (progressively updating historical values using a consistent approach).
- Substation rating data was extracted from SIFT and the Equipment Rating (ERAT) database and was based on the limiting factor i.e. Transformers, cables or circuit breakers.

Table 1.2 below sets out the sources from which Energex obtained the required information.

Table 1.2: Information sources

Variable	Source
Substation Rating	ERAT / SIFT
Raw adjusted maximum demand (MW)	SIFT / SCADA
Raw adjusted maximum demand (MVA)	SIFT / SCADA

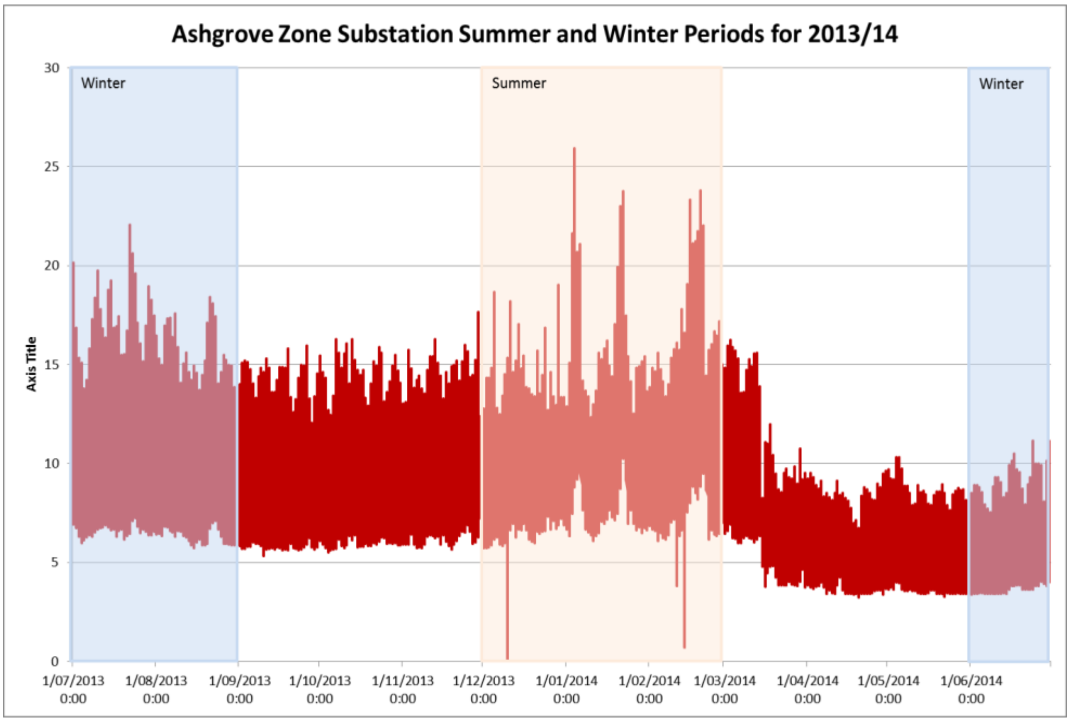
Variable	Source
Date maximum demand occurred	SIFT / SCADA
Half hour time period maximum demand occurred	SIFT / SCADA
Winter/Summer peaking	SIFT / SCADA
Adjustments – Embedded generation	NLF
Weather Corrected maximum demand 10% POE (MW)	SIFT / SCADA / BOM
Weather Corrected maximum demand 10% POE (MVA)	SIFT / SCADA / BOM
Weather Corrected maximum demand 50% POE (MW)	SIFT / SCADA / BOM
Weather Corrected maximum demand 50% POE (MVA)	SIFT / SCADA / BOM

1.3 Methodology

1.3.1 Assumptions

Energex applied the following assumptions to the data used to calculate the weather adjusted data at the zone substation level:

- Where the zone substation has insignificant variables or contribution to demand, these values were excluded from the calculation.
- The duration of the winter period is June, July and August.
- The duration of the summer period is December, January and February.
- Graph 1 below as an example, shows the half hourly MW load for an Energex zone substation during the 13/14 year. It demonstrates that the loads peaked in Jan-14 (which was in the EGX defined summer period), and it hit high in late Jul-13 (also sit in the EGX defined winter period). There were no big spikes outside those two periods in the 13/14 year. Therefore, they are consistent with what AER requires.



(Graph 1 --- Half Hourly MW Load in Ashgrove Zone Substation in 13/14 Year)

- The temperature threshold was based on the average for each day.
- Any day where the average temperature at Amberley was above 16.0 degrees Celsius during the winter period was disregarded.
- Any day where the average temperature at Amberley was below 23.5 degrees Celsius during the summer period was disregarded.
- The temperature data was based on the daily minimum and maximum temperatures, with the weekday, weekend and Friday temperatures all identified separately in the model, allowing both the day and temperature affects to be adjusted for.
- The weather data sourced from the Bureau of Meteorology was based on five weather stations, including Maroochydore, Brisbane Airport, Archerfield, Coolangatta and Amberley.
- Energex system peak half hour for winter and summer was used to determine the time and date for Coincident demand at the zone and bulk supply substations.

1.3.2 Approach

Energex applied the following approach to obtain the required information:

- Substation rating data was extracted from the SIFT database and the ERAT database. The rating was the normal cyclic rating which corresponds to the time of the raw adjusted maximum demand. The Normal Cyclic rating is the maximum permissible peak daily loading for the given load cycle that a transformer can supply under normal conditions each day of its life, through summer and winter ambient temperature, without reducing the designed life of the transformer. Normal conditions is described as the system state where all plant are configured in its intended operational state, without planned or forced outages on any plant item.

- The historical demand data stored in SIFT was extracted from the SCADA system for each substation and stored as raw recorded data. Adjustments were then made based on temporary switching or situations where the network was not in a normal state. These adjustments also accounted for embedded generation to produce a native demand for each substation for day and night for each season. Energex uses adjusted Raw maximum demand values for the RIN.

- For substations where it was identified that the non-coincident MVA occurred at a different time to the non-coincident MW, a separate table is attached showing the non-coincident peak demand in MVA. Refer to Attachment 1c – MD and Utilisation Spatial – Peak MVA Differing from Peak MW.

- Non-coincident and coincident MVA values were stored based on the recorded MW and MVA compensation operating at the half hour of peak demand. The time and date of each peak was recorded in SIFT for each substation and season (I.e. summer or winter).

- The peak values recorded for 2014 are based on the greater of the historical maximum demand for the summer of 2013/14, and the historical maximum demand for the winter of 2014.

- Substations without ratings are customer substations.

- Embedded generation is stored separately based on the metering data and the substation or bulk supply substation parent. The embedded generation within Energex is generally small in size and is Non-scheduled generation including Rocky Point (the largest in the Energex area of supply).

The temperature adjustment process used by Energex was based on the following process and is documented in the Energex procedure document 674:

- The days that are unlikely to produce a peak demand were excluded.

- Multiple seasons of data were used and then normalised to remove annual growth.

- A multiple regression model was developed for daily maximum demand incorporating maximum temp, minimum temp, and variables for Fridays, Weekdays and the Christmas shut down period. D = f (MIN, MAX, Weekday, Xmas Shutdown, Fridays, constant and error term).

- The model and weather station with the best fit was used in the Monte Carlo simulation to determine the 10POE and 50POE adjustments for each zone substation. The adjustments were applied to the raw peak demand to calculate the 10POE and 50POE adjusted demands.

The 10POE and 50POE adjustment factors are stored against each season for each zone substation.

Table 1.3 provides details of decommissioned Sub-transmission Substations

Table 1.3: Decommissioned Sub-transmission Substations

Sub-Station	Year
Australian Paper Mill	2013
Airport Link Kedron (Construction)	2011
Airport Link Toombul (Construction)	2012
Amberley (Old)	2009
Currumbin Package	2009
Ebbw Vale T1- T2	2010
Ebbw Vale T4, T5 – T6	2010
North South Bipass Tunnel	2009

1.4 Estimated Information

No Estimated Information was reported.

2 BoP 5.2.1 – Asset Age Profile - Installed Assets Currently in Commission

The AER requires Energex to provide the following information relating to Table 5.2.1 – Asset Age Profile:

Asset Volumes currently in commission, split by the following asset categories:

- **Poles By: Highest Operating Voltage ; Material Type; Staking (if wood)**
- **Pole top structures, disaggregated by highest operating voltage**
- **Overhead Conductors By: Highest Operating Voltage; Number Of Phases (at HV)**
- **Underground Cables By: Highest Operating Voltage**
- **Transformers By: Mounting Type; Highest Operating Voltage ; Ampere Rating; Number Of Phases (at LV)**
- **Switchgear By: Highest Operating Voltage ; Switch Function**
- **Public Lighting By: Asset Type ; Lighting Obligation**

Estimated Information was provided for the following figures:

- **Poles By: Highest Operating Voltage ; Material Type; Staking (if wood)**
- **Pole top structures, disaggregated by highest operating voltage**
- **Overhead Conductors By: Highest Operating Voltage; Number Of Phases (at HV)**
- **Underground Cables By: Highest Operating Voltage**
- **Transformers By: Mounting Type; Highest Operating Voltage ; Ampere Rating; Number Of Phases (at LV)**
  - **Pole mounted; < = 22kV ; < = 60 kVA ; Single Phase**
  - **Pole mounted; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase**
  - **Pole mounted; < = 22kV ; < = 60 kVA ; Multiple Phase**
  - **Pole mounted; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase**
  - **Pole mounted; > 22 kV ; > 600 kVA**
  - **Kiosk mounted; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase**
  - **Kiosk mounted; < = 22kV ; > 600 kVA ; Multiple Phase**
  - **Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; < = 60 kVA ; Multiple Phase**
  - **Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 60 kVa and < = 600 kVa ; Multiple Phase**
  - **Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 600 kVa ; Multiple Phase**
  - **Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; < = 15 MVA**
  - **Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 15 MVA and < = 40 MVA**

- Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 40 MVA
- Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 15 MVA and < = 40 MVA

- Switchgear By: Highest Operating Voltage ; Switch Function
  - < = 11 kV; Operational Switch (Years 1910/11 and 1965/66 – 2001/02)
- Public Lighting By: Asset Type ; Lighting Obligation
  - Luminaires; Major Road
  - Luminaires; Minor Road
  - Brackets; Major Road (Year 1910/11)
  - Brackets; Minor Road (Year 1910/11)
  - Lamps; Major Road
  - Lamps; Minor Road

All other figures reported are Actual Information.

These variables are a part of Regulatory Template 5.2 – Asset Age Profile.

This Basis of Preparation excludes:

- **Asset Category: Service Lines By: Connection Voltage; Customer Type; Connection Complexity – which is covered in a Basis of Preparation 5.2.2.**
- **Mean Economic Life and Standard Deviation information across all asset groups: which is covered in Basis of Preparation 5.2.3**
- **Asset Category: SCADA, Network Control and Protections Systems By: Function – which is covered in a Basis of Preparation 5.2.4.**

2.1 Consistency with Reset RIN Requirements

Table 2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 2.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Where Energex provides asset sub-categories corresponding to the prescribed asset categories in Table 5.2.1, Energex must ensure that the expenditure and asset replacement / asset failure volumes of these sub-categories reconcile to the higher level asset category. Energex is required to insert additional rows and provide a clear indication of the asset category applicable to each sub-category. Energex must provide corresponding replacement expenditure data in regulatory template 2.2 as per its instructions.	The categories were reported in accordance with the values in Regulatory Template 2.2 - Repex

Estimated Information was provided for the following figures:

- Poles By: Highest Operating Voltage ; Material Type; Staking (if wood);
- Pole top structures, disaggregated by highest operating voltage;
- Overhead Conductors By: Highest Operating Voltage; Number Of Phases (at HV);
- Underground Cables By: Highest Operating Voltage;
- Transformers By: Mounting Type; Highest Operating Voltage ; Ampere Rating; Number Of Phases (at LV) – Only Specific Values (please refer to outline above);
- Switchgear By: Highest Operating Voltage ; Switch Function – Only Specific Values (please refer to outline above); and
- Public Lighting By: Asset Type ; Lighting Obligation – Only Specific Values (please refer to outline above).

All other information reported is Actual Information.

2.2 Sources

Table 2.2 below sets out the sources from which Energex obtained the required information.

Table 2.2: Information sources

Variable	Source
Poles By: Highest Operating Voltage ; Material Type; Staking (if wood)	NFM
Pole top structures, disaggregated by highest operating voltage	NFM
Overhead Conductors By: Highest Operating Voltage; Number Of Phases (at HV)	NFM
Underground Cables By: Highest Operating Voltage	NFM
Transformers By: Mounting Type; Highest Operating Voltage ; Ampere Rating; Number Of Phases (at LV)	NFM
Switchgear By: Highest Operating Voltage ; Switch Function	NFM
Public Lighting By: Asset Type ; Lighting Obligation	NFM

2.3 Methodology

All data was extracted from NFM. These data extracts were then manipulated in excel to account for various items in the figures.

2.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

Poles By: Highest Operating Voltage; Material Type; Staking (if wood)

- The pole data does not include assets that are in store or held for spares.
- The pole data was categorised by the highest voltage at the site. For example if a site carries 33kV and 11kV conductors, then all poles at the site were allocated as 33kV poles.
- All non-staked and nailed poles have a year of commissioning based on the first year the current specification was allocated to the slot in NFM.
- A pole with a pole foundation type of staked and nailed has an age profile of when the pole foundation was made staked and nailed and not as per first year of current specification.
- Poles that have a material type of plastic were excluded.
- Aluminium poles were combined with steel poles.
- Poles with a dedicated streetlight pole specification and contain a rate 1 or rate 2 streetlight has not been included in the asset group poles but was included in the public lighting asset group.
- All poles with no voltage such as cross street and bollard poles were allocated to the <=1kV category.
- Poles were allocated based on financial year, i.e. an asset captured in NFM on 5th July 2012 will have a commissioning period of 2012/13.
- The total quantity and year of commissioning is a snapshot of all relevant assets as of 30 June 2014.

Overhead Conductors By: Highest Operating Voltage; Number of Phases (at HV)

- The conductor data does not include conductors that are in store or held for spares.
- Total quantities are reported in kilometres.
- The length of each conductor category is the total conductor route length and not each individual phase conductor length, noting:
  - 11kV routes predominately consist of 3 conductors.11kV routes also includes some and single phase (2 conductors) in its total length.
  - LV routes predominately consist of 4 conductors: 3 phases plus neutral; however lengths provided includes all variations.

Underground Cables By: Highest Operating Voltage

- The underground cable data does not include cables that are in store or held for spares.
- Total quantities are reported in kilometres.
- The length of each conductor category is the total cable route length and not each individual core length.

Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV)

- The transformer data does not include transformers that are in store or held for spares.

Switchgear By: Highest Operating Voltage; Switch Function

- The switchgear data does not include assets that are in store or held for spares.
- Circuit Breakers asset group was defined as all circuit breakers and reclosers within the Energex network excluding circuit breakers that form part of a Ring Main Unit.
- Operational Switch asset group was defined as all other switches found within Energex network, This includes the asset types Airbrake, Disk Link, Link Pillar, Isolator, Switch Fuse, Dropout, Earth Switch, Fuse Switch, Sectionaliser, Load Transfer Switch, Ring Main Unit, Link Pillar and Disconnect Box.

Public Lighting By: Asset Type; Lighting Obligation

- The public lighting data does not include assets that are in store or held for spares.

2.3.2 Approach

Energex applied the following approach to obtain the required information:

Poles By: Highest Operating Voltage; Material Type; Staking (if wood)

1) A report was extracted from NFM that detailed the poles in the Energex network with the following corresponding information:
    a. The pole material.
    b. The pole foundation.
    c. The original installation year.
    d. The number of poles.

    This report excluded all poles that are not currently in use by Energex and also removes all duplicate entries that may be inherent within the NFM database.

The report output from NFM was then analysed in Excel to produce the figures required in table 5.2.1. Adjustments were required to be made for:

a. Poles dated pre-1920.

b. Allocation of poles made of other or unknown materials.

c. Errors in staked and nailed poles.

d. Pre-1970 Steel LV poles.

e. Poles without an assigned voltage (cross street and bollard poles).

2) When data migration occurred into NFM in 1999, assets that were contained within the original database that did not have a known age were allocated an install date of 1920 or earlier. Any pole actually this old will have had a like for like replacement since then and if this was before 1999 the date not historically recorded. So as a result all assets with an age falling within this period were pro-rated into the pre spatial NFM period 1970 to 1999.

Poles	*Null Date*	*1900-1920*
< = 1 kV; WOOD	9	2442
> 1 kV & < = 11 kV; WOOD	2	978[1]
> 11 kV & < = 22 kV; WOOD	0	0
> 22 kV & < = 66 kV; WOOD	0	133
> 66 kV & < = 132 kV; WOOD	0	2
> 132 kV; WOOD	0	0
< = 1 kV; CONCRETE	0	78
> 1 kV & < = 11 kV; CONCRETE	0	77
> 11 kV & < = 22 kV; CONCRETE	0	0
> 22 kV & < = 66 kV; CONCRETE	0	8
> 66 kV & < = 132 kV; CONCRETE	0	0
> 132 kV; CONCRETE	0	0

Poles	*Null Date*	*1900-1920*
> 1 kV & < = 11 kV; STEEL	0	2
> 11 kV & < = 22 kV; STEEL	0	0
> 22 kV & < = 66 kV; STEEL	0	0
> 66 kV & < = 132 kV; STEEL	0	0
> 132 kV; STEEL	0	0

1. This value contains a single pole that doesn't have a material type.

3) Some poles had material descriptions other than what was specified in the template. These were treated as follows.

- Poles that have a material type of plastic were excluded.

Plastic Poles	*Quantity*
< = 1 kV	13
> 1 kV & < = 11 kV	11
> 22 kV & < = 66 kV	0
> 66 kV & < = 132 kV	0

- Aluminium poles were combined with steel poles.

Aluminium Poles	*Quantity*
< = 1 kV	318
> 1 kV & < = 11 kV	0
> 22 kV & < = 66 kV	0
> 66 kV & < = 132 kV	0

- All poles that cannot be allocated a material type or age because they do not have a specification recorded in NFM were pro-rated a material based on the ratio of existing known material types; See the following table for numbers of unknown poles as at 30 June 2014.

Asset group		*Pro Rata*		
Pole Max Voltage	Unknown Quantity	Concrete	Steel	Wood
< = 1 kV	1003	1%	45%	54%
> 1 kV & < = 11 kV	275	3%	0%	97%
> 22 kV & < = 66 kV	42	3%	2%	95%
> 66 kV & < = 132 kV	14	*35%*	*11%*	*54%*

4) Staked and nailed poles with an age of older than 1996 is deemed to be in error. The trial of pole nailing within Energex only occurred during the 1995-96 period and started rolling out into the network in 1998.

Asset Category	*Quantity in Error*
< = 1 kV; STAKED	3,692
> 1 kV & < = 11 kV; STAKED	2,512
> 11 kV & < = 22 kV; STAKED	0
> 22 kV & < = 66 kV; STAKED	163

Due to the short life of a pole nailing it was deemed that a linear representation would skew the data in the wrong direction. For this reason the following percentages were applied:

Pole Nailing Allocation	*Percentage*
2001	35%
2000	28%
1999	22%
1998	15%

5) Steel LV poles with a date record pre 1970 were pro-rated to the period of 1970 to1999. This was done because (a) LV steel poles have a mean life of 22 years and all poles prior to 1970 were deemed to be data anomalies and (b) the NFM data after 1999 is considered to be sound.

LV Steel Poles	*Quantity*
1900 – 1970	196
Null Date	194

6) All poles with no voltage such as cross street and bollard poles were allocated to the <=1kV category

7) To ensure that the final figures reported are consistent with the overall figures extracted, calculated fields have had minor manual adjustments to ensure that rounding errors do not occur from the pro-ration. All manual changes only affect the year with the maximum number of assets assigned to it by a maximum of one asset. Where more than one asset is needed to balance the rounding error then the next maximum number of assets is modified by a maximum of one and so on until the value is balanced. Where multiple years share identical number of assets then the modification occurs from oldest to the youngest asset.

Pole top structures, disaggregated by highest operating voltage

1) Pole top structures are defined to be cross arms fitted to poles. The following multipliers were applied against the figures calculated for pole assets to determine the quantity of cross arms and their initial ages. Multipliers were determined from

Energex maintenance department based upon field sampling conducted and knowledge of construction types and their application.

Asset Type	Multiplier
< = 1 kV; STAKED	1.2438
> 1 kV & < = 11 kV; STAKED	1.35
> 11 kV & < = 22 kV; STAKED	0
> 22 kV & < = 66 kV; STAKED	1.35
> 66 kV & < = 132 kV; STAKED	1
> 132 kV; STAKED	1
< = 1 kV; WOOD	1.2438
> 1 kV & < = 11 kV; WOOD	1.35
> 11 kV & < = 22 kV; WOOD	0
> 22 kV & < = 66 kV; WOOD	1.35
> 66 kV & < = 132 kV; WOOD	1
> 132 kV; WOOD	1
< = 1 kV; CONCRETE	1.35
> 1 kV & < = 11 kV; CONCRETE	1.35
> 11 kV & < = 22 kV; CONCRETE	1
> 22 kV & < = 66 kV; CONCRETE	1.35
> 66 kV & < = 132 kV; CONCRETE	0.5

Asset Type	Multiplier
> 132 kV; CONCRETE	0.5
< = 1 kV; STEEL	0
> 1 kV & < = 11 kV; STEEL	0
> 11 kV & < = 22 kV; STEEL	0
> 22 kV & < = 66 kV; STEEL	0
> 66 kV & < = 132 kV; STEEL	0
> 132 kV; STEEL	0

2) It was then assumed that all cross arms prior to 1978/79 was replaced with a consecutive 35 year life span. For example a 1977/78 start date is updated to 2013/14 to indicate that the asset was replaced. A 1934 cross arm will inherit a new asset age of 2003/4 to represent two changes with a 35 year life for each cross arm.

Overhead Conductors By: Highest Operating Voltage; Number Of Phases (at HV)

1) Energex does not have complete installation records for overhead conductors. As such, no actual age information was available and the overhead conductor age was estimated using the applicable pole age.

2) A report was run from NFM that gave the Energex overhead conductors broken down by:

    a. Conductor sizing category (Imperial, Metric or Other).

    b. The circuit for each conductor.

    c. The minimum pole ages within each circuit.

All lengths extracted exclude any vertical components to the conductor, such as sag.

3) Excluded from this report were conductors known to be owned by customers. Conductors are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets. When this occurs Energex has captured these conductors. In

addition, assets that were sold to customers and Energex believes that there is a benefit to continue to store this data, the data has not been removed from NFM.

4) To minimise the effect of captured customer conductors, it was assumed that where a conductor is connected to only customer assets then that conductor is also customer owned.

Customer Conductor	*Quantity*
Overhead	8.07

5) The following methodology was then used to estimate the age profile:

   a. 1929-30 was deemed to be the minimum possible age of any conductor by Energex's technical standards.

   b. All conductors were placed into 3 categories by delineating them based on imperial and metric sizing:

      i. Imperial –This conductor category consists of conductors that use imperial sizing such as 7/0.80 and were superseded by metric conductors. These conductors were used from 1930 – 1980

      ii. Metric – This conductor category was used from 1970 till present, these use metric sizing such as MARS 7/.375

      iii. Other – This conductor category consists of imperial sizing that Energex currently uses such as 7/12 Steel, therefore these conductors are deemed to be used from 1930 - present.

   c. All conductors were then logically grouped together based on circuit (continuous conductor spans between two operational points in the network) and conductor category.

   d. All conductors then inherited the minimum pole age that is acceptable within the particular grouping. Where an acceptable pole age cannot be found, the adjacent circuits were analysed to determine if an acceptable age profile could be found. Where an acceptable age profile could not be found all conductors with a metric category were allocated an age of 1974-75 and all conductors with an imperial category were allocated an age of 1944-45.

6) To ensure that the final figures reported are consistent with the overall figures extracted, calculated fields have had minor adjustments to ensure that rounding errors do not occur. All manual changes only affect the year with the longest length by a maximum of one kilometre. Where more than one kilometre is needed to balance the rounding error then the next maximum length is modified by a maximum of one kilometre and so on and so forth until the value is balanced. Where multiple years share identical lengths then the modification occurs from oldest to the younger asset.

Underground Cables By: Highest Operating Voltage

1) Energex does not have complete installation records for underground cables. In the late 1990’s when Energex conducted its network data capture exercise, the business case was based on operational and planning benefits which did not require asset management information such as installation date or any history to be kept for cables. As such, no actual age information was available and the underground cable age was estimated using the age of connected assets.

2) A report was run from NFM that gave the Energex underground cables broken down by:

    a. Cable sizing category (Imperial, Metric or Other).

    b. The circuit for each cable.

    c. The minimum connected asset ages within each circuit.

All lengths stated exclude any vertical components to the cable, such as vertical tails.

3) Excluded from this report were cables known to be owned by customers. Cables are not allocated an ownership value, which generally means that customer owned conductors are not captured within NFM. There are a few instances where Energex is required to control the network through these customer owned assets, when this occurs Energex has captured these conductors captured. In addition assets that were sold to customers and Energex believes there is a benefits to continue to store this data the data has not be removed from NFM.

To minimise the effect of captured customer cables, it was assumed that where a cable is connected to only customer assets then that cable is also customer owned.

Customer Conductor	*Quantity (km)*
Underground Cable	14.01

4) The following methodology was used to estimate the age profile:

    a. 1929-30 was deemed to be the minimum possible age of any conductor by Energex’s technical standards.

    b. All cable were placed into 3 categories by delineating them based on imperial and metric sizing:

        i. Imperial –This cable category consists of cables that use imperial sizing such as 0.15sq and were superseded by metric cables. These conductors were used from 1930 – 1980.

        ii. Metric – This cable category was used from 1970 till present, these use metric sizing such as 240mm sq.

        iii. Other – This cable category consists of imperial sizing that Energex uses. There are no underground cable that fall into this category, if cable did exist they would have an acceptable age profile from 1930 - present.

c. All cables were logically grouped together based on circuit (continuous connection between two operational points in the network) and cable category. All cables then inherited the minimum age of the connected assets that was acceptable within the particular grouping. Where an acceptable asset age could not be found, the adjacent circuits were analysed to determine if an acceptable age profile could be found. Where an acceptable age profile could be found, all conductors with a metric category are allocated an age of 1974-75 and an imperial category are allocated an age of 1944-45.

5) The methodology above uses the minimum date a connected asset was installed. Unlike poles, which have had a maintained age prior to NFM, the underground network has many assets that were not tracked prior to NFM. As such, the data capture exercise performed when migrating to NFM caused 2 notable spikes in the originally extracted data: 2001-02 period for the underground LV network and 1999-00 for the 11kV network. To smooth out these spikes the data was distributed back until 1985. This was because 1985 was the year in which contractors took over subdivision development and there was a push to have all subdivisions made underground from this point forward within the Energex region. The table below outlines the parameters used to distribute these values.

Title	*LV*	*11kV*
Base Year	2002	2000
Original Length	5,870km	1,537km
Base Year Allocation *This allocation is based on total expected trend, for this period, while also correcting rounding errors*	92km	97km
Available amount to allocate	5,778km	1,440km
Allocation Range	1985-2002	1985-2000
Number of years	18yrs	15yrs[1]
Allocation per year	321km	96km

Note 1: Year 1999 was not allocated an additional amount as total shown was within tolerances.

6) Due to rounding errors inherent within the above methodology, some cables had to be manually added to or subtracted from to ensure consistency of the final figure. All manual changes were added to or subtracted from only once from any particular year, with the max number of assets within a particular asset group being added to or subtracted from first, then followed by the second and third largest years and so forth. Where equal values exist between two years then the modifications are updated from the oldest to youngest assets.

Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV)

A report was run from NFM which counted the number of transformers broken down by:

- Mounting type.
- Capacity.
- Phasing.

Transformers recorded in NFM as being connected to the network were counted in the total number of assets and year of commissioning information. This method gave (a) the most accurate number currently in use and (b) the date that connectivity information is captured correlates closely with the actual commissioning date.

1) In this extract the year indicated for each asset type is the year the asset was manufactured. If this date was unknown or incorrect (less than 1910 or greater than 2014) then the first event associated with the asset (usually purchase date) was used. If this date was unknown then the date the slot was installed into NFM was used.

2) This report was imported into excel and transformers with the following unknown values were required to be adjusted for:
   a. Transformers with unknown ratings.
   b. Transformers with unknown dates.
   c. Transformers with unknown phasing.

All values were allocated by pro-rating across known asset quantities in each category.

3) Transformers with an unknown rating were allocated a rating based on existing percentage breakdown of assets. Please see below table for details.

4) Transformers that have an unknown date were allocated an age based on existing percentage breakdown. Please see the below table for the quantity of transformers without a date that were pro-rated in the age profile with the assets that had no rating.

Transformer Type	*Percentage Unknown Rating*	*Unknown Rating Quantity*	*Unknown Age Quantity*	*Count of Assets to Age*
POLE MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE	17.434%	58	1216	1274
POLE MOUNTED ; < = 22kV ; > 60 kVA and < = 600 kVA ; SINGLE PHASE	0.02%	0	0	0

Transformer Type	*Percentage Unknown Rating*	*Unknown Rating Quantity*	*Unknown Age Quantity*	*Count of Assets to Age*
POLE MOUNTED ; < = 22kV ; > 600 kVA ; SINGLE PHASE	0.00%	0	0	0
POLE MOUNTED ; < = 22kV ; < = 60 kVA ; MULTIPLE PHASE	19.03%	64	908	972
POLE MOUNTED ; < = 22kV ; > 60 kVA and < = 600 kVA ; MULTIPLE PHASE	63.61%	250	5160	5410
POLE MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE	0.00%	0	0	0
POLE MOUNTED ; > 22 kV ; < = 60 kVA	0.00%	0	0	0
POLE MOUNTED ; > 22 kV ; > 60 kVA and < = 600 kVA	0.00%	0	0	0
POLE MOUNTED ; > 22 kV ; > 600 kVA	100.00%	5	1	6
POLE MOUNTED ; > 22 kV ; < = 60 kVA	0.00%	0	0	0
POLE MOUNTED ; > 22 kV ; > 60 kVA and < = 600 kVA	0.00%	0	0	0
POLE MOUNTED ; > 22 kV ; > 600 kVA	0.00%	0	0	0
KIOSK MOUNTED ; < = 22kV ; < = 60 kVA ; SINGLE PHASE	0.00%	0	0	0
KIOSK MOUNTED ; < = 22kV ; > 60 kVA and < = 600 kVA ; SINGLE PHASE	0.00%	0	0	0
KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; SINGLE PHASE	0.00%	0	0	0
KIOSK MOUNTED ; < = 22kV ; < = 60 kVA ; MULTIPLE PHASE	0.00%	0	0	0
KIOSK MOUNTED ; < = 22kV ; > 60 kVA and < = 600 kVA ; MULTIPLE PHASE	78.64%	90	744	864
KIOSK MOUNTED ; < = 22kV ; > 600 kVA ; MULTIPLE PHASE	21.36%	24	218	242
KIOSK MOUNTED ; > 22 kV ; < = 60 kVA	0.00%	0	0	0
KIOSK MOUNTED ; > 22 kV ; > 60 kVA and < = 600 kVA	0.00%	0	0	0

Transformer Type	*Percentage Unknown Rating*	*Unknown Rating Quantity*	*Unknown Age Quantity*	*Count of Assets to Age*
KIOSK MOUNTED ; > 22 kV ; > 600 kVA	0.00%	0	0	0
KIOSK MOUNTED ; > 22 kV ; < = 60 kVA	0.00%	0	0	0
KIOSK MOUNTED ; > 22 kV ; > 60 kVA and < = 600 kVA	0.00%	0	0	0
KIOSK MOUNTED ; > 22 kV ; > 600 kVA	0.00%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; < = 60 kVA ; MULTIPLE PHASE	0.06%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 60 kVa and < = 600 kVa ; MULTIPLE PHASE	18.16%	25	31	56
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 kV ; > 600 kVa ; MULTIPLE PHASE	81.79%	99	436	535
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 kV & < = 33 kV ; < = 15 MVA	6.55%	3	8	11
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 kV & < = 33 kV ; > 15 MVA and < = 40 MVA	1.58%	1	0	1
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > = 22 kV & < = 33 kV ; > 40 MVA	91.87%	42	15	57
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 kV & < = 66 kV ; < = 15 MVA	0.00%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 kV & < = 66 kV ; > 15 MVA and < = 40 MVA	100.00%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 kV & < = 66 kV ; > 40 MVA	0.00%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 kV & < = 132 kV ; < = 100 MVA	95.56%	19	3	22
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 kV & < = 132 kV ; > 100 MVA	4.44%	1	0	1

Transformer Type	*Percentage Unknown Rating*	*Unknown Rating Quantity*	*Unknown Age Quantity*	*Count of Assets to Age*
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 132 kV ; < = 100 MVA	0.00%	0	0	0
GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 132 kV ; > 100 MVA	0.00%	0	0	0

5) Transformers with unknown phasing were pro-rated into the known totals for each phasing category and then pro-rated across the years.

6) To ensure that the final figures reported are consistent with the overall figures extracted, calculated fields have had minor adjustments to ensure that rounding errors do not occur. All manual changes only affect the year with the maximum number of assets assigned to it by a maximum of one asset. Where more than one asset was needed to balance the rounding error then the next maximum number of assets was modified by a maximum of one and so on and so forth until the value was balanced. Where multiple years share identical number of assets then the modification occurs from oldest to the youngest asset.

Switchgear By: Highest Operating Voltage: Switch Function

1) A report was run within NFM which extracted the number of switchgear assets broken down by operating voltage and switch function. Switchgear which was recorded in NFM as being connected to the network was counted in the total number of assets and year of commissioning information. This excluded Link Pillars, Ring Main Units and Disconnect Boxes as these assets do not have a connectivity connection. This method gave (a) the most accurate number currently in use and (b) the date that connectivity information was captured correlates closely with the actual commissioning date.

2) The following definitions were used in the extraction of the data:

   a. The switchgear data did not include assets that are in store or held for spares.

   b. Operational Switch asset group was defined as all other switches found within Energex network, This includes the asset types Airbrake, Disk Link, Link Pillar, Isolator, Switch Fuse, Dropout, Earth Switch, Fuse Switch, Sectionaliser, Load Transfer Switch, Ring Main Unit, Link Pillar and Disconnect Box.

   c. Circuit Breakers asset group was defined as all circuit breakers and reclosers within the Energex network excluding circuit breakers that form part of a Ring Main Unit.

3) The year indicated for each asset type was the year the asset was manufactured, if this date was unknown or incorrect (less than 1910 or greater than 2014) then the first event associated with the asset (usually purchase date) was used. If this date was unknown then the date the slot was installed into NFM was used. No other date

information was available for some assets with dates less than 1910. These assets constituted approximately 0.12% and were allocated to 1911.

4) There was a large spike of <=11kV switches in the 1999-2002 period due to the increased scope of data capture caused by the NFM data capture project. To account for this spike, the assets captured during this period were allocated based on the mean life of the asset type.

Customer Conductor	*Quantity (km)*
Total to Allocate 1999-2002	72,708
Base Allocation 2002	1,000
Base Allocation 2001	1,000
Base Allocation 2000	1,000
Base Allocation 1999	1,000
Available Allocation	68,708
Mean Age	48
Current Year	2,014
Base Year	2,003
Number of Year No Allocation Required	11
Years to Allocate	37
Allocate Till	1,966
Quantity Allocated Each Year	1,856

5) To ensure that the final figures reported are consistent with the overall figures extracted, calculated fields have had minor adjustments to ensure that rounding errors do not occur. All manual changes only affect the year with the maximum number of assets assigned to it by a maximum of one asset. Where more than one asset was needed to balance the rounding error then the next maximum number of assets was modified by a maximum of one and so on and so forth until the value was balanced. Where multiple years share identical number of assets then the modification occurs from oldest to the youngest asset.

Public Lighting By: Asset Type; Lighting Obligation

1) A report was extracted from NFM which counted each public light broken down by the following information:

   a. Streetlight age.

b. Streetlight rate.

c. Billing type.

d. Lamp category.

2) This report did not include assets that are in stores or held for spares. Also, only rate 1 and 2 streetlights have been included in the extract. Rate 1 streetlights are designed, constructed, owned and operated (maintained) by Energex. Rate 2 streetlights are customer designed and constructed which are owned, operated and maintained by Energex. Rate 3 and 8 streetlights were not included as they are owned and operated by the customer and not required to be maintained by Energex. Rate 9 streetlights were not included as they are watchman lights and did not fit the criteria of a streetlight for the CA RIN.

Luminaires

1) Initial luminaire installations are captured within NFM; however, subsequent streetlight head changes are not captured, so for this reason an age profile had to be estimated. It was assumed that all streetlights prior to 1980 have been replaced with a consecutive 20 year life span. For example a 1979 start date was updated to 1999 to indicate that the asset was replaced. A 1934 streetlight will inherit a new asset age of 1994 to represent three head changes with a 20 year life for each.

2) Major and minor allocations for luminaires were based on the billing type of the lantern.

Lamps

1) Detailed lamp information is not stored within the Energex corporate systems. For this reason estimates were applied based on the average life of assets lamps. Average life of lamps can be broken into two categories, mercury vapour and other lamp types. Mercury vapour lights have an average life of 5 years and all other lights have an average life of 4 years.

All lights that were installed prior to the average life expectancy (prior to 2006 for Mercury Vapour and 2010 for other types) have been accumulated and applied consistently into each year.

Type	*Mercury*	*Other*
Average life span	5yr	4yr
Major Quantity	2,747	66,293
Minor Quantity	136,478	35,904
Major Allocation per Year	549.4	16,573.25

Type	*Mercury*	*Other*
Minor Allocation per Year	27,295.6	8,976

Brackets

1) It was assumed that a bracket was installed for all streetlights that are mounted on a pole. Due to very limited number of brackets being replaced, all brackets have inherited the original streetlight age profile.

Poles

1) Poles were deemed to be a streetlight pole when the specification was public lighting specific and contained a rate 1 or 2 streetlight. The age of the poles was taken as the original streetlight age profile.

2) The categorisation of poles to major or minor was inherited from the streetlights attached to the pole. Where multiple streetlights existed on the pole the major streetlight took precedence.

2.4 Estimated Information

Estimated Information was provided for the following line items:

- Poles By: Highest Operating Voltage ; Material Type; Staking (if wood).
- Overhead Conductors By: Highest Operating Voltage; Number Of Phases (at HV).
- Underground Cables By: Highest Operating Voltage.
- Transformers By: Mounting Type; Highest Operating Voltage ; Ampere Rating; Number Of Phases (at LV):
  - Pole mounted; < = 22kV ; < = 60 kVA ; Single Phase.
  - Pole mounted; < = 22kV ; > 60 kVA and < = 600 kVA ; Single Phase.
  - Pole mounted; < = 22kV ; < = 60 kVA ; Multiple Phase.
  - Pole mounted; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase.
  - Pole mounted; > 22 kV ; > 600 kVA.
  - Kiosk mounted; < = 22kV ; > 60 kVA and < = 600 kVA ; Multiple Phase.
  - Kiosk mounted; < = 22kV ; > 600 kVA ; Multiple Phase.
  - Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; < = 60 kVA ; Multiple Phase.
  - Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 60 kVA and < = 600 kVA ; Multiple Phase.

– Ground Outdoor / Indoor Chamber Mounted; < 22 kV ; > 600 kVA ; Multiple Phase.
– Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; < = 15 MVA.
– Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 15 MVA and < = 40 MVA.
– Ground Outdoor / Indoor Chamber Mounted; > = 22 kV & < = 33 kV ; > 40 MVA.
– Ground Outdoor / Indoor Chamber Mounted; > 33 kV & < = 66 kV ; > 15 MVA and < = 40 MVA.
– Switchgear By: Highest Operating Voltage ; Switch Function:
– < = 11 kV; Operational Switch (Years 1910/11 and 1965/66 – 2001/02).

- Public Lighting By: Asset Type ; Lighting Obligation:
  – Luminaires; Major Road.
  – Luminaires; Minor Road.
  – Brackets; Major Road (Year 1910/11).
  – Brackets; Minor Road (Year 1910/11).
  – Lamps; Major Road.
  – Lamps; Minor Road.

2.4.1 Justification for Estimated Information

Poles By: Highest Operating Voltage; Material Type; Staking (if wood)

All data for poles was extracted directly from the NFM system, however, certain anomalies in this data were required to be adjusted for manually. These adjustments related to:

- Poles dated pre-1920.
- Allocation of poles made of other or unknown materials.
- Errors in staked and nailed poles.
- Pre-1970 Steel LV poles.
- Poles without an assigned voltage (cross street and bollard poles).

Due to the inherent pro-rating methodologies and assumptions used in these adjustments, all data for poles was estimated.

Overhead Conductors By: Highest Operating Voltage; Number of Phases (at HV)

- Energex does not have complete installation records for overhead conductors. As such, no actual age information was available and the overhead conductor age was estimated using the applicable pole age.

Underground Cables By: Highest Operating Voltage

- Similar to the overhead conductors above, Energex does not have complete installation records for underground cables. As such, no actual age information was available and the underground cable age was estimated using the age of connected assets.

Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV)

- The line items that have been estimated are stated above. These line items were estimated due to a number of transformers lacking data that would allow them to be classified. The unknown data was in relation to:
  - Transformers with unknown ratings.
  - Transformers with unknown dates.
  - Transformers with unknown phasing.
- No other source data was available for these transformers and they were required to be spread across the transformers with complete data.

Switchgear By: Highest Operating Voltage; Switch Function

- Some switchgear within the category “< = 11 kV; Operational Switch” had a date prior to 1910/11 which was deemed to be incorrect but no other date information was available to be used to assign a date. These assets were therefore estimated to be within the 1910/11 year.

Public Lighting By: Asset Type; Lighting Obligation

- Initial luminaire installations are captured within NFM; however, subsequent streetlight head changes are not captured, so for this reason an age profile had to be estimated.
- Detailed lamp information is not stored within the Energex corporate systems. For this reason estimates were applied based on the average life of assets lamps.
- Brackets dated prior to 1910/11 were deemed to be in error, however no other information was available to assign a year. These values were therefore estimated as being in the 1910/11 year.

2.4.2 Basis for Estimated Information

Poles By: Highest Operating Voltage; Material Type; Staking (if wood)

- The following adjustments were made to the pole data extracted from NFM:
  - Poles dated pre-1920.
  - Allocation of poles made of other or unknown materials.
  - Errors in staked and nailed poles.
  - Pre-1970 Steel LV poles.
  - Poles without an assigned voltage (cross street and bollard poles).
- For the detailed methodology of each of the adjustments please refer to the approach section above.

Overhead Conductors By: Highest Operating Voltage; Number of Phases (at HV)

- For the detailed estimation methodology of how overhead conductor age was based on the pole age, please refer to the approach section above.

Underground Cables By: Highest Operating Voltage

- For the detailed estimation methodology of how underground conductor age was based on the age of connected assets, please refer to the approach section above.

Transformers By: Mounting Type; Highest Operating Voltage; Ampere Rating; Number of Phases (at LV)

- The figures that were estimated incorporate some transformers with unknown data. These transformers were pro-rated across each category and/or year based on the quantities of transformers that were able to be fully categorised. For full details of the estimation please refer to the approach section above.

Switchgear By: Highest Operating Voltage; Switch Function

- Some switchgear within the category “< = 11 kV; Operational Switch” and with a date prior to 1910/11 with a lack of date information were assigned to the 1910/11 year. This was considered to be the best estimate with the lack of available information.

Public Lighting By: Asset Type; Lighting Obligation

- Luminaires have been estimated by using a 20 year life span and assuming that each one was replaced on this schedule. For full details please refer to the approach section above.

- Lamps have been estimated by using the average asset lives of lamps (5 years for Mercury Vapour and 4 years for other types) and assuming that each was replaced on this schedule. For full details please refer to the approach section above.
- Bracket lives for 1910/11 have been estimated as those brackets with lives prior to 1910/11 and no other descriptive information to assign a year have been assigned to that year.

2.5 Explanatory notes

- Where, in Regulatory Template 2.2, Energex provided estimated expenditure data on the basis of historical data that included works across asset groups, Energex provided the asset age profile data in Regulatory Template 5.2 against the most elementary asset category (as per RIN regulatory requirement).

3 BoP 5.2.2 – Asset Age Profile – Service Lines

The AER requires Energex to provide the following information relating to Table 5.2.1 – Asset Age Profile:

- **Asset Volumes currently in commission for asset group - Service Lines By: Connection Voltage; Customer Type; Connection Complexity**

All figures are Estimated Information.

These variables are a part of Regulatory Template 5.2 – Asset Age Profile.

3.1 Consistency with Reset RIN Requirements

Table 3.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Service lines Includes assets that provide a physical link and associated assets between the distribution network and a customer's premises. It excludes any pole mounted assets and meters that are included in any other asset group.	Addressed below in the methodology and assumptions.
Simple commercial/industrial connection low voltage Single/multi-phase *customer* service *connection* and, as an example, may involve the following: – One or more spans of overhead service wire; – Road crossing (overhead or underground). – Small LV extension or augmentation of overhead and/or underground mains.	Addressed below in the methodology and assumptions.

All information reported is estimated information.

3.2 Sources

Table 3.2 over page sets out the sources from which Energex obtained the required information.

Table 3.2: Information sources

Variable	Source
Service Lines By: Connection Voltage; Customer Type; Connection Complexity	MARS
Service Cable – Replacements	Sheets (Manually Captured)

3.3 Methodology

- Overhead service line asset information is stored in MARS (Meter Asset Register and Service system). MARS does not record the age of assets, but it does record the type of conductor. The type of conductor has been used to estimate the age of the assets.
- Based on the definitions specified in the RIN, Energex has only LV service line assets. Where customers require more complex connections and the assets are owned by Energex they are included in the other dedicated asset category (e.g. 11 kV overhead conductor) and are not classified as HV service lines.

3.3.1 Assumptions

- Energex applied the following assumptions to obtain the required information:
- Maximum age of a service line is 60 years.
- All new service line assets are XLPE. Energex only owns LV service line assets. A Customer may have their own private Network past the HV connection point however Energex does not model/capture their assets. For example, consumers own the mains from underground pillars at the property boundary to their meter position, so no underground services are included in the count.
- All LV service lines are a single span making them simple connections.

3.3.2 Approach

Energex applied the following approach to obtain the required information:

The breakdown of service line conductor was extracted from MARS though the following logic:

1) The total quantity of OH service lines were extracted based on unique property addresses:
   a. All NMIs with the same street number are recorded as one NMI to accommodate unit blocks.
   b. Instances of NMIs with no street number were counted once for each lot number

c. Instances of NMIs with no street number and no lot number were counted once.

2) Each record needed to have a National Metering Identifier (NMI) associated with the property with one of the following statuses for the NMI:

   a. Active (’A’).

   b. De-Energised (‘D’).

   c. Can be metered or unmetered.

3) Overhead services were identified as:

   a. A NMI with a supply type which does not start with a ‘U%’ identifier (unless the Pole Value indicates overhead) or a “null” identifier.

   b. A pole value that does not start with SC, SG, SS or ‘U%’ identifier. (SC, SG and SS denotes substation sites, and U% are underground pillar sites).

New Installs / Replacements / Asset Age

1) The replacement volume and recent installation information was used to estimate the installation of XLPE type cables over the last 17 years. Remaining cable types were spread evenly across the estimated age range.

2) Quantities of assets inspected/maintained for service lines were based on the number of services maintained during the year, as opposed to the number of customers.

3) The expected age range of the different generations of cables was then included to determine the age profile. These assumptions are as per Table 3.3 below:

Table 3.3: Expect Age Range for Cable Types

CABLE_TYPE	Age range (yrs)
B (Bare Open)	Any
N (Concentric Neutral)	27-38
O (Open wire Neutral)	38+
P (Parallel web)	17-38
T (Twisted multiphase)	17-38
X (XLPE)	0-17
XMT (XLPE Mitti)	7-9
Y (4x95 XLPE)	0-17
UNKNOWN	Any

4) The next step was to generate an age profile for each cable type based on:

   a. The expected age range of assets in-service.

   b. Maximum life of service lines.

c. Known replacement and installation volumes over the last 5 years.

5) After the total service line population was determined the profile was split into Residential, Commercial & Industrial and Simple and Complex.

   The split between Residential and Commercial & Industrial service lines was based on the overall customer base, where 8.2% of customers are Commercial &Industrial and the balance Residential.

3.4 Estimated Information

- All figures reported for service lines is Estimated Information.

3.4.1 Justification for Estimated Information

- Energex has not historically maintained the installation dates of overhead service lines, therefore an estimate was required.

3.4.2 Basis for Estimated Information

- The conductor type held within MARS is a reliable source of data that is continually validated and corrected by field inspection. As different conductor types have been installed historically it gives a reasonable estimate of the age profile.

3.5 Explanatory notes

- For LV connections, Energex does not own the underground cable from the pillar to the premise. Therefore only overhead services were included in the table.

- Between 2005/6 and 2004/5 there were a low number of cables remaining in service. This is due to the replacement program for a specific type of XLPE cable that exhibited problems with degraded insulation.

4 BoP 5.2.3 – Asset Age Profile – Economic Life and Standard Deviation

The AER requires Energex to provide the following information relating to Table 5.2.1 – Asset Age Profile:

Mean economic life and standard deviation for the following asset groups:

- **Poles, disaggregated by highest operating voltage and material type**
- **Pole top structures, disaggregated by highest operating voltage**
- **Overhead conductors, disaggregated by highest operating voltage and number of phases**
- **Underground cables, disaggregated by highest operating voltage**
- **Service lines, disaggregated by, connection voltage, customer type and connection complexity**
- **Transformers, disaggregated by mounting type, highest operating voltage, ampere rating and number of phases**
- **Switchgear, disaggregated by highest operating voltage and switch function**
- **Public lighting, disaggregated by asset type and lighting obligation**
- **SCADA, network control and protections systems, disaggregated by function**

All figures are Estimated Information.

These variables are a part of Regulatory Template 5.2 – Asset Age Profile.

4.1 Consistency with Reset RIN Requirements

Table 4.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Definition of economic life: An asset's economic life is the estimated period after installation of the new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. The period of effective service needs to consider the life cycle costs between keeping the asset in commission and replacing it with its modern equivalent. Life cycle costs of the asset include those associated with the design, implementation, operations, maintenance, renewal and rehabilitation, depreciation and cost of finance.	Demonstrated in Methodology section below.

Requirements (instructions and definitions)	Consistency with requirements
Where Energex provides asset sub-categories corresponding to the prescribed asset categories in Table 5.2.1, Energex must ensure that the expenditure and asset replacement / asset failure volumes of these sub-categories reconcile to the higher level asset category. Energex is required to insert additional rows and provide a clear indication of the asset category applicable to each sub-category. Energex must provide corresponding replacement expenditure data in regulatory template 2.2 as per its instructions	Demonstrated in Methodology section below.
In instances where Energex is reporting expenditure associated with asset refurbishments/ life extensions capex it must insert additional rows at the bottom of the table for the relevant asset group to account for this. Energex must provide the required data, applying the corresponding asset category name followed by the word "REFURBISHED". Energex must provide corresponding replacement expenditure data in regulatory template 2.2 as per its respective instructions.	Demonstrated in Methodology section below.
In instances where Energex wishes to provide asset sub-categories in addition to the specified asset categories in table 5.2.1, Energex must provide a weighted average asset economic life, including mean and standard deviation that reconciles to the specified asset category in accordance with the following formula: $$\text{Economic life of asset category}=\sum_{i=1}^{n}\left(\left(\frac{\text{value of asset sub-category}_i}{\text{total value of asset category}}\right)\times\text{economic life of asset sub-category}_i\right)$$ where: n is the number of sub-categories to reconcile with the asset category Asset values are determined by the asset category's contribution to the current replacement cost of the network. This being the most recent per unit cost of replacement for each asset, multiplied by the number of those assets in service and reported in the asset age profile.	Demonstrated in Methodology section below.

All information reported is estimated information.

4.2 Sources

Table 4.2 over page sets out the sources from which Energex obtained the required information.

Table 4.2: Information sources

Asset Group	Variable	Source
Poles	ALL Poles - Wood	NFM
	ALL Refurbished poles wood	NFM
	ALL Poles – Steel and Concrete	Engineering Assessment
Pole Top Structures	ALL	Energex CBRM - Cross arms v2.0
Overhead Conductor	< ≈ 1 KV	Engineering Assessment
	> 1 KV & < ≈ 11 KV	Engineering Assessment
	> 11 KV & < ≈ 22 KV ; SWER	
	> 22 KV & < ≈ 66 KV	Engineering Assessment
	> 66 KV & < ≈ 132 KV	Engineering Assessment
Underground Cables	< ≈ 1 KV	Engineering Assessment
	> 1 KV & < ≈ 11 KV	Engineering Assessment
	> 22 KV & < ≈ 66 KV	EGX CBRM - 33kV Gas Cables v3.0 EGX CBRM - 33kV Oil Filled Cables v3.0 EGX CBRM - 33kV Solid Cables v3.0
	> 66 KV & < ≈ 132 KV	Energex CBRM - 110kV Oil Filled Cables v3.0 Energex CBRM - 110kV Solid Cables v3.0
Service Lines	ALL	Regulatory life
Transformers	POLE MOUNTED ; < ≈ 22KV ; < ≈ 60 KVA ; SINGLE PHASE	Energex CBRM - Pole Mounted TX v3.0
	POLE MOUNTED ; < ≈ 22KV ; > 60 KVA AND < ≈ 600 KVA ; SINGLE PHASE	
	POLE MOUNTED ; < ≈ 22KV ; > ≈ 600 KVA ; SINGLE PHASE	
	POLE MOUNTED ; < ≈ 22KV ; < ≈ 60 KVA ; MULTIPLE PHASE	
	POLE MOUNTED ; < ≈ 22KV ; > 60 KVA AND < ≈ 600 KVA ; MULTIPLE PHASE	
	KIOSK MOUNTED ; < ≈ 22KV ; < ≈ 60 KVA ; MULTIPLE PHASE	Energex CBRM - Ground & Pad Mounted TX v3.0

Asset Group	Variable	Source
	KIOSK MOUNTED ; < ≈ 22KV ; > 60 KVA AND < ≈ 600 KVA ; MULTIPLE PHASE	
	KIOSK MOUNTED ; < ≈ 22KV ; > 600 KVA ; MULTIPLE PHASE	
	KIOSK MOUNTED ; > 22 KV ; < ≈ 60 KVA	
	KIOSK MOUNTED ; > 22 KV ; > 60 KVA AND < ≈ 600 KVA	
	KIOSK MOUNTED ; > 22 KV ; > 600 KVA	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 KV ; < ≈ 60 KVA ; MULTIPLE PHASE	Energex CBRM - Ground & Pad Mounted TX v3.0
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 KV ; > 60 KVA AND < ≈ 600 KVA ; MULTIPLE PHASE	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; < 22 KV ; > 600 KVA ; MULTIPLE PHASE	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > ≈ 22 KV & < ≈ 33 KV ; < ≈ 15 MVA	EGX CBRM 33kV TX v3.1
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > ≈ 22 KV & < ≈ 33 KV ; > 15 MVA AND < ≈ 40 MVA	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > ≈ 22 KV & < ≈ 33 KV ; > 40 MVA	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 33 KV & < ≈ 66 KV ; > 15 MVA AND < ≈ 40 MVA	
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 KV & < ≈ 132 KV ; < ≈ 100 MVA	EGX CBRM 110.132kV TX v3.1
	GROUND OUTDOOR / INDOOR CHAMBER MOUNTED ; > 66 KV & < ≈ 132 KV ; > 100 MVA	
Switchgear	< ≈ 11 KV ; CIRCUIT BREAKER	EGX CBRM 11kV CB v3.3 Energex CBRM - reclosers v3.0
	> 11 KV & < ≈ 22 KV ; CIRCUIT BREAKER	
	< ≈ 11 KV ; OPERATIONAL	Engineering Assessment

Asset Group	Variable	Source
	SWITCH	
	> 11 KV & < ≈ 22 KV ; OPERATIONAL SWITCH	
	> 22 KV & < ≈ 33 KV ; CIRCUIT BREAKER	EGX CBRM 33kV CB v3.2
	> 33 KV & < ≈ 66 KV ; CIRCUIT BREAKER	
	> 22 KV & < ≈ 33 KV ; OPERATIONAL SWITCH	Engineering Assessment
	> 33 KV & < ≈ 66 KV ; OPERATIONAL SWITCH	
	> 66 KV & < ≈ 132 KV ; CIRCUIT BREAKER	EGX CBRM 110.132kV CB v3.1
	> 66 KV & < ≈ 132 KV ; OPERATIONAL SWITCH	Engineering Assessment
Public Lights	Luminaires	Manufacturer's specification
	Brackets and Poles	Network Asset Management documentation
	Lamps	Public lighting maintenance contract and customer billing data
SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS	ALL	Engineering Assessments and Regulatory lives

4.3 Methodology

- Condition Based Risk Management (CBRM) is the tool used for asset replacement planning on a condition and risk management basis. CBRM analysis was reviewed in November / December 2013 for developing asset replacement programs for the forthcoming regulatory control period and is based on various asset classes in the network. It was therefore considered applicable to use this analysis for the Reset RIN.
- For the majority of asset classes, economic life data was extracted from CBRM models. For asset classes where Energex does not have CBRM to model asset condition, engineering assessments were performed to estimate the mean economic life.
- In all cases the standard deviation of economic life was approximated by the square root of the mean.

4.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Standard deviation of economic life was approximated by the square root of the mean in accordance with the AER guidance.
- The economic life of < = 22kV wood poles was assumed to be the same as11kV wood poles.
- The economic life of low voltage steel poles was assumed to be the same as11kV steel poles.
- The economic life of SWER conductor was assumed to be the same as11kV conductor.
- The economic life of low voltage cables (i.e., <=1kV) was assumed to be the same as 11kV cables.
- The economic life of poles with unknown voltage (i.e., <=1kV) have been included with low voltage poles.
- The economic life of pole mounted single phase transformers was assumed to be the same as multi-phase pole mounted transformers.
- The economic life of ground mounted/indoor chamber mounted transformers >33kV and < 66kV was assumed to be the same as 33kV ground mounted/indoor chamber mounted transformers.
- The economic life of >11kV and <22kV circuit breakers and switches was assumed to be the same as11kV circuit breakers and switches respectively.
- The economic life of >33kV and <66kV circuit breakers and switches was assumed to be the same as 33kV circuit breakers and switches respectively.
- Steel poles include steel mono poles and steel lattice towers.

4.3.2 Approach

- Economic life information for the majority of asset classes was extracted from CBRM models. Where CBRM models had not been undertaken on particular asset category, engineering assessments were undertaken to estimate economic life of assets.

CBRM Models

- CBRM is an approach to asset replacement planning that forecasts the future condition of assets and enables the modelling and evaluation of different investment scenarios.

- CBRM enables asset lives to be expressed based on attributes of assets combined with its location and duty in the network. The input values used in the CBRM models were developed through workshops with key stakeholders, taking account of factors such as original specification, manufacturer, operational experience, obsolescence, maintenance issues and operating conditions (duty, proximity to coast, etc). Whilst the values for average asset lives used in CBRM model are based on subjective information, they are calibrated against historic asset failures and replacements. The calibration is reviewed regularly to ensure it remains relevant as new asset populations are introduced and mature.

- As an example, if a particular type of circuit breaker in the population began to manifest issues as a result of manufacturing or engineering factors, the observed failures would be factored into the calibration review. This in turn would modify the expected life of the population.

Modified expected life

- Where CBRM was used to provide data for economic life, it was calculated as the “modified expected life” field within each of the CBRM models.

- The modified expected life field was calculated based on the following:
  - Each asset was assigned an average asset life based on asset type or manufacturer.
  - Duty and location factors specific to the asset are then applied, based on known attributes such as load or distance to coast.

- The combination of these pieces of information in the CBRM model produces a value for the modified expected life.

- As an example, a power transformer in a corrosive environment (i.e. outdoors close to the coast), will have a significantly shorter life than a power transformer located in a more benign, dry environment.

Wood Poles and Refurbished Wood Poles

The economic life for wood poles was calculated based on analysis of data extracted from NFM. The following process was applied:

- Data for each pole was extracted from NFM listing the date of installation and date of replacement. Data was provided in an Access database and imported into Excel for analysis.

- The dataset was filtered to only include poles replaced following an inspection (as opposed to poles replaced under capital augmentation works). These poles were identified based on a flag in ellipse.

- The period the pole was in service was then calculated for each pole in the dataset. This was determined based on the difference between the date the pole was replaced and the date the pole was installed.

- Each pole was then mapped to an asset category (consistent with the RIN Table 5.2.1), based on the voltage attributed to the pole.

- At this point, a number of poles types were also excluded from dataset on the basis that they did not represent condition based replacements, namely:
  - Replacement age of wood poles >66kV. These poles were excluded due to the dataset being too small to provide a representative economic life.
  - Poles replaced <=5 years from installation date. Poles replaced within 5 years of installation are unlikely to be due to the condition of the asset. As a consequence, these poles were removed from the analysis.

- The economic life for each asset category was then determined by calculating the average service life across all poles in the asset category.

Only a small dataset was available for the asset category, "> 66 KV and < ≈ 132 KV; WOOD", and this data did not provide a representative economic life. In the absence of an appropriate dataset, the average asset life for "> 66 KV and < ≈ 132 KV; WOOD" was determined by calculating the average asset life across all wood poles.

Refurbished wood poles

- Data used to derive the age of nailed poles at time of replacement excludes poles nailed prior to 1995, as this was when nailing program first commenced. Owing to small populations on a voltage split basis, all nailed poles were considered as a single dataset to derive average replacement age from date of nailing. The data was included in the template as Refurbished Wood Poles in accordance with the AER's guidance.

Concrete and Steel Poles

- A data set was not available for concrete pole actual replacement life due to their long service life and relatively new population age. As a result, the economic life for concrete poles was estimated based on the manufacturer's specification and general industry expectations.

- A data set was not available for steel pole actual replacement life due to their long service life and ability to extend life through ongoing inspection and preventive maintenance programs. As a result, the economic life for steel poles was estimated based on manufacturer's specification and general industry expectations. This data set does not include public lighting poles.

Service Lines

- The mean replacement life for service lines was based on Energex's regulatory asset lives for low voltage overhead service line.

Overhead Conductor

- The mean economic life for overhead conductors was estimated based on general industry life expectations.

Underground Cable

- The mean economic life for underground cables >11kV was extracted from CBRM models.
- The mean economic life for underground cables ≤11kV was estimated based on general industry life expectations.

Operational Switches

- The mean economic life for operational switches was estimated based on general industry life expectations.

Public Lighting

Luminaires

- The mean economic life for luminaires (both major and minor) was based on the manufacturer's product specification. No differentiation was made between luminaires for major and minor roads on the basis that the manufacturer's claimed service life is identical for major and minor road luminaire fittings currently purchased.

Brackets and Poles

- The mean economic life for both brackets and poles were considered together based on the similar nature of the assets (i.e., the replacement of poles and brackets generally occur concomitantly). No differentiation was made between poles and brackets on major and minor roads on the basis that the mean economic life is equivalent for major and minor poles and brackets.
- The mean economic life for poles and brackets was calculated based on the weighted average age of the population of:
  - Base Plate Mounted poles, which have an economic life of 50 years (this was based on Energex's Asset Management Division expectations. Note that the population of Base Plate Mounted poles was relatively young compared to the anticipated economic life, hence there was limited failure trend data available).
  - Buried in Ground poles, which have an economic life of 30 years (this was based on failure trend occurring at approximately 25 years of age as advised from Energex's Asset Management Division).
- Timber poles were excluded from the calculation due to the relatively small population of timber poles used for street lighting purposes.

Lamps

- The mean economic life for major and minor road lamps was based on the actual replacement rate of lamps sourced from the maintenance contract. The following steps were applied (separately for major and minor road lamps):
  – The volume of lamp replacements for each year between 2008-09 and 2012-13 was collated from the maintenance contract history spreadsheet. These values were then averaged to produce an annual lamp replacement rate for the five year period.
  – The total population of lamps was also collated (based on current billed Rate 1 and Rate 2 street lighting sites at the end of each financial year). Similar to the above, these values were averaged to produce a value representing the annual population of lamps over the five year period.
  – The lamp economic life was then calculated by dividing the average annual lamp replacement rate over the average annual lamp population for both major and minor road luminaires.

SCADA, NETWORK CONTROL AND PROTECTION SYSTEMS

This asset group includes a number of categories:

- Field devices;
- Local network wiring assets;
- Communications network assets;
- Communications site infrastructure;
- Master station assets;
- Linear communications assets; and
- AFLC

Energex also used a number of subcategories to calculate the economic life, as set out in the Table 4.3 below:

Table 4.3: Asset Classes

Asset Group	Category
FIELD DEVICES	Protection Relays (MB)
	RTUs (MM)
	IEDs (PM)
LOCAL NETWORK WIRING ASSETS	LOCAL NETWORK WIRING ASSETS
COMMUNICATIONS NETWORK ASSETS	Microwave links (links installed)

Asset Group	Category
	DSS Head ends
	DSS Radios (including repeaters)
	Multiplex (including MPLS nodes)
COMMUNICATIONS SITE INFRASTRUCTURE	Tower/pole
	Battery
	Charger
	Diesel
	Air conditioning
	Site security
	Management
	Solar
	TLIU
MASTER STATION ASSETS	MASTER STATION ASSETS
LINEAR COMMUNICATIONS ASSETS	Copper pilots (meters of cable installed)
	Fibre Pilots (meters of cable installed)
AFLC	Motor generator
	SFU

- For protection relays the life was estimated based on an average of 50 years for electromechanical relays and 15 years for modern digital relays (results in a life of 32.5 years). The 50 year and 15 years figures were based on current industry life expectations of the relays.
- For RTUs the mean economic life was based on analysis on historical records of asset replacement (11.6 years).
- For microwave links, DSS infrastructure and Multiplex equipment a figure of 12 years was utilised based on the equipment having an anticipated life similar to that of an RTU.
- For Local Wiring assets the life was estimated by averaging the lives of the equipment that the wiring predominately interconnects, noting that the wiring is normally replaced as part of replacing the larger asset.
- For Linear Communications Assets, asset anticipated lives for underground copper cables (60 years), overhead copper cables (30 years) were averaged to give 45

years for copper pilot cables. For overhead / underground fibre cables, 30 years was utilised. Note bracketed figures came from the finance system.

- For Master Station asset the SPARQ policy document “ICT Infrastructure Asset Renewal Guidelines” was consulted. The document states a forecast replacement age of 5 years for the types of servers utilised in the Master Station.
- For Communications Site Infrastructure the lives of the various sub components were used to generate an asset category mean life.
- For AFLC the life was derived from the average of the motor generator and SFU modified expected life from the CBRM model (EGX CBRM AFLC v3.7).
- The economic life for each asset category was determined by calculating the volume weighted average of the subcategory asset lives.

4.4 Estimated Information

- All values provided for mean economic life are Estimated Information.
- All values provided for the standard deviation are Estimated Information as they are derived from the mean economic life.

4.4.1 Justification for Estimated Information

- Distribution asset populations are rarely homogeneous. Whilst asset classes comprise of assets with similar functionality, the specifications and treatment of the assets change over time. The outcome of this situation is that even where historic information exists, the assumptions and treatment of that data can have a material impact on the forecast economic life.

4.4.2 Basis for Estimated Information

- In all cases Energex based its Estimated Information on data driven process to the extent possible (as detailed in the approach) followed by peer review of the values.

4.5 Explanatory notes

- Where Energex does not own assets that meet the category an economic life of zero was entered.

5 BoP 5.2.3 – Asset Age Profile – SCADA, Network Control and Protections Systems By: Function

This Basis of Preparation covers the quantity of assets currently in commission (by year) for SCADA, Network Control and Protection systems assets, broken down by the following asset categories:

- **Field Devices**
- **Local Network Wiring Assets**
- **Communications Network Assets**
- **Master Station Assets**
- **Communications Site Infrastructure**
- **Communications Linear Assets**
- **AFLC**

These figures are a part of Regulatory Template 5.2 – Asset Age Profile.

Estimated Information was provided for the following asset categories:

- **Local Network Wiring Assets**
- **Multiplex age profile (sub component of Communications Network Assets)**
- **Master Station Assets**
- **Telephone Line Isolation Units (sub component of Communications Site Infrastructure)**

All other figures reported are Actual Information.

These variables are a part of Regulatory Template 5.2 – Asset Age Profile.

This Basis of Preparation excludes:

- **Installed Assets Currently in Commission (all other categories) which are covered in BoPs 5.2.1 and 5.2.2**
- **Mean Economic Life and Standard Deviation information across all asset groups: which is covered in Basis of Preparation 5.2.3**

5.1 Consistency with Reset RIN Requirements

Table 5.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
When Energex must make an estimate because it cannot populate the input cell with actual information, Energex must demonstrate that it has provided the best estimate it can.	Refer to Estimates section below.

Estimated Information was provided for the following figures:

- Local Network Wiring Assets;
- Multiplex age profile; and
- Master Station Assets.

All other figures reported are Actual Information.

5.2 Sources

Table 5.2 below sets out the sources from which Energex obtained the required information.

Table 5.2: Information sources

Variable	Source
Field Devices • Protection Relays • Remote Terminal Units (RTUs) • Intelligent Electronic Devises (IEDs)	IPS SCADA Base and project documentation SCADA Base
Local Network Wiring Assets	MCCS
Communications Network Assets • Microwave links • Distribution Systems SCADA (DSS) Head Ends • DSS Radios • Multiplex and MPLS	CBMD ROSS ROSS Project Documentation and DB2MGR
Master Station Assets	Internal Excel spreadsheet
Communications Site Infrastructure • Comms Towers and Poles • Comms Batteries • Comms Battery Chargers • Diesel generators	Information is manually maintained in an excel spread sheet, with the exception of the TLIU installs which are estimates

Variable	Source
• Comms Site Air conditioners • Comms Site Security equipment • Comms Site Management equipment • Comms Site Solar Cells • Telephone line Isolation equipment (TLIU)	
Communications Linear Assets	CBMD
AFLC	NFM

5.3 Methodology

5.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- In relation to IEDs and DSS Radios, the database only contains initial commissioning information. Subsequent data associated with maintenance swap outs (i.e. replacements) is not captured due low cost of the equipment. As a result, this tends to overstate the age of the IED and DSS Radio fleet; however, this was not considered a significant issue on the basis that IEDs and DSS Radios are typically low cost in nature.

5.3.2 Approach

Energex has broken down each asset category into separate asset subcategories.

Asset Group	Category
FIELD DEVICES	Protection Relays
	RTUs
	IEDs
LOCAL NETWORK WIRING ASSETS	LOCAL NETWORK WIRING ASSETS
COMMUNICATIONS NETWORK ASSETS	Microwave links (links installed)
	DSS Head ends
	DSS Radios (including repeaters)

Asset Group	Category
	Multiplex (including MPLS nodes)
MASTER STATION ASSETS	MASTER STATION ASSETS
COMMUNICATIONS SITE INFRASTRUCTURE	Comms Towers and Poles
	Comms Batteries
	Comms Battery Chargers
	Diesel generators
	Comms Site Air conditioners
	Comms Site Security equipment
	Comms Site Management equipment
	Comms Site Solar Cells
	Telephone line Isolation equipment (TLIU)
COMMUNICATIONS LINEAR ASSETS	Copper pilots (meters of cable installed)
	Fibre Pilots (meters of cable installed)
AUDIO FREQUENCY LOAD CONTROL (AFLC)	Generator based AFLC injection equipment
	Solid State based AFLC injection equipment

A number of different methods were used to obtain the required data for each of the asset subcategories, as outlined below.

Field Devices

- Protection relays – a report detailing all assets currently in commission with installation dates was extracted from IPS. The data was extracted into an Excel spreadsheet and analysed to produce the age profile data. The total number of protection relays installed in each year was determined by summing the number individual relays installed during the year.

- RTUs – a review of SCADA control scheme design documentation was undertaken to identify the date when the hardware for each control scheme was changed or installed. By analysing the date when a control scheme was replaced with new hardware, this showed when a new asset was added. The age profile of RTUs was generated by summing the total number of hardware replacements or installations in each financial year.

- IEDs – the only class of IED that records were available for was Serial Interface Control Module (SICM) equipment. SICM represents the largest class of IEDs in SCADA in Energex's network. A report was generated from the SCADA Base application that detailed the commissioning date of each IED. The data was extracted into an Excel spreadsheet and analysed to produce the age profile data. The total number of IED assets installed in each year was determined by summing the number individual IEDs installed during the year.

The total number of installed assets relating to field devices was established by summing the asset volumes calculated for protection relays, RTUs and IEDs.

Local Network Wiring Assets

- For the purposes of the Local Network Wiring Assets, Energex has focussed on data relating to substation multicore cabling, as this represents the primary local network wiring asset class for Energex.
- Energex's systems do not specifically record the date that each multicore cable was installed, and as a result the age profile was estimated.
- The total volume of multicore cables currently installed in substation assets was extracted from the Multicore Cable Schedule (MCCS) database (at August 2014). This volume was then reduced to account for new cables installation between 1 July 2014 and August 2014, based on an engineering assessment.
- Energex has previously submitted an age profile for local wiring assets and retained this estimate and estimated the total number of cables installed in the 13/14 financial year by subtracting the previous estimate for the total number of cables from the current estimate of total number of cables.

Communications Network Assets

- Microwave links – The Communications Bearer Management Database (CBMD) application was queried to determine the commissioning dates for each link. This produced a list of all microwave links with the associated installation date. The data was then analysed in a separate Excel spreadsheet to determine the total number of links installed in each financial year.
- DSS Head end, radios and repeaters – The Radio Operational Support System (ROSS) application database was queried to provide the commissioning date for each asset. This produced a list of the hardware that was installed and the date of installation and commissioning. The data was analysed in a separate Excel spreadsheet to determine the total volume of equipment commissioned in each financial year.
- Multiplex –An extract of the total population of multiplex assets was performed and the total assets installed in 13/14 was estimated by subtracting the current population number from the population as recorded for 12/13. The age profile for multiplex assets was estimated in the 12/13 CA RIN submission and this data was used in this submission to estimate pre 13/14 volumes. The per 12/13 age profile for multiplex assets was estimated by analysing the installation dates associated fibre optic cables and then using these dates as a basis for apportioning the volume of multiplex assets installed for each year.

- Multi-protocol label switching (MPLS) – Volumes for MPLS assets were obtained from relevant project documentation which identified the dates of installation for each MPLS asset. The data was input into a separate Excel spreadsheet and the total volume MPLS assets installed in each year were determined by summing the number individual assets installed during the year.

The total number of installed assets relating to communication network assets was established by summing the asset volumes calculated for microwave links, DSS head end, radios and repeaters, Multiplex and MPLS assets.

Master Station Assets

- Energex's support group for the Master Station assets maintains an Excel spreadsheet that details information about Master Station server assets. A commissioning date was estimated by the support group based on commissioning of a recent project.

Communications Site Infrastructure

- For Towers/poles, Batteries, Battery Charger, Diesel Generators, Air Conditioners, Site Security, Site Management and Solar installations, a spread sheet is maintained of commissioning date. The data was analysed in a separate Excel spreadsheet to determine the total numbers installed in each financial year.

- For Telephone Line Isolation Units no reliable source of installations date was available. Using Engineering assessment the figure of 250 was chosen as the total population. Discussion with Field staff suggested that the units were installed starting around 1990. With no other data that could be used to approximate per year installation a flat figure was chosen (10 per year).

The total number of installed assets relating to Communications Site Infrastructure was established by summing the asset volumes calculated and estimated above.

Communications Linear Assets

- Communications Linear Assets – the CBMD application database was queried to determine commissioning dates for each point to point pilot cable link (both fibre optic cables and copper cables). The data was extracted into an Excel spreadsheet and analysed to produce the age profile data. The total length of pilot cables installed in each year was determined by summing the individual pilot cable lengths installed during the year.

Audio Frequency Load Control (AFLC)

- AFLC – the installation date for each AFLC installation was extracted from NFM into an excel spreadsheet. The installation dates were analysed in the excel spreadsheet to determine the per financial year number of units installed.

5.4 Estimated Information

5.4.1 Justification for Estimated Information

- Energex does not have historical data for local network wiring assets, multiplex assets, Telephone Line Isolation Units and master station assets. As such Estimated Information provided for the volume of installed assets by year.

5.4.2 Basis for Estimated Information

- The volume of local network wiring assets at 30 June 2014 was estimated based on the current volume of installed assets (at August 2014) less an amount to account for new installations between 1 July 2014 and August 2014. This amount was based on an engineering assessment. The estimates produced for the 12/13 CAN RIN were retained.

- The volume of installed multiplex assets for each year prior to 2012-13 was estimated by apportioning the total amount of multiplex assets in 2012-13 against the asset age profile of fibre optic cables.

- The volume of installed master station assets for each year prior to 2012-13 was based on an assumption that each asset was commissioned three years prior to the manufacturer's warranty expiry date.

- For Telephone Line Isolation Units no reliable source of installations date was available. Using Engineering assessment the figure of 250 was chosen as the total population. Discussion with Field staff suggested that the units were installed starting around 1990. With no other data that could be used to approximate per year installation a flat figure was chosen (10 per year).

- The detailed methodology for these asset categories can be found in the methodology section above.

6 Appendix 1 – Maximum Demand and Utilisation Spatial – Peak MVA Differing from Peak MW.

Refer to Supporting information contained in Regulatory Submission RIN Supporting Documents, Section 32.1.

Energex

Reset RIN

Basis of Preparation

6. Service and Quality

October 2014

energex

positive energy

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the fast growing region of South East Queensland. Energex provides distribution services to almost 1.4 million connections, delivering electricity to 2.8 million residents and businesses across the region.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Section 6 – Service and Quality

1 BoP 6.1 – Telephone Answering

The AER requires Energex to provide the following information relating to Table 6.1.1 – Telephone Answering Data

For each day for the period 1 July 2009 – 30 June 2013:

- **Total number of calls received**
- **Total number of calls received less calls to payment lines and automated interactive services**
- **Total number of calls received less calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator**
- **Sub-total number of calls received**
- **Calls to the fault line answered in 30 seconds**

Where the call received are calls to the fault line.

Actual information was provided for:

- **all call data components where daily call data extracts were available.**
- **Estimated information was provided on dates where no call data extracts were available.**

These variables are a part of Regulatory Template 6.1 – Telephone Answering.

1.1 Consistency with Reset RIN Requirements

Table 1.1 over page demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 1.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must provide information within the relevant reportable year for the following: • Total number of calls received • Total number of calls received less calls to payment lines and automated interactive services • Total number of calls received less calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator • Sub-total number of calls received • Calls to the fault line answered in 30 seconds	Demonstrated in section 1.3
The AER's definition of calls answered within 30 seconds is as follows: Calls to the fault line answered in 30 seconds where the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered	Energex's response in table 6.1.1 is consistent with this definition.

Requirements (instructions and definitions)	Consistency with requirements
by any response) and the caller speaks with a human operator, but excluding the time that the caller is connected to an automated interactive service that provides substantive information. This measure does not apply to: • calls to payment lines and automated interactive services; • calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator. Where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned. Note: Being placed in a queuing system (automated or otherwise) does not constitute a response. 'Calls answered within 30 seconds' and 'Calls received' should be calculated excluding calls abandoned within 30 seconds of being queued for a human operator; and calls to payment lines and automated interactive services.	

Actual information was provided for

- Total number of calls received;
- Total number of calls received less calls to payment lines and automated interactive services;
- Total number of calls received less calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator; and
- Calls to the fault line answered in 30 seconds

Estimated information was provided for the above metrics on days where data extracts were not available.

1.2 Sources

Table 1.2 below sets out the sources from which Energex obtained the required information.

Table 1.2: Information sources

Variable	Source
Total number of calls received	iReport
Total number of calls received less calls to payment lines and	Telstra Call Centre Analyser

Variable	Source
automated interactive services	(CCA)
Total number of calls received less calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator	Telstra Call Centre Analyser (CCA)
Calls to the fault line answered in 30 seconds	Telstra Call Centre Analyser (CCA)

1.3 Methodology

- Energex utilises a hosted telephone service provided by Telstra. This Genesys system is provided and supported by Telstra and has been in place at Energex since 2005. All phone calls received by Energex are handled by the Genesys system. The Genesys system incorporates a reporting tool named Call Centre Analyser (CCA). CCA is used to provide daily statistics on phone calls including total number of calls and number of calls answered in 30 seconds.
- Energex has a number of phone numbers including a Loss of Supply line, Emergency line and General Enquiry Line. In accordance with the specification, calls reported are calls to the Loss of Supply line. The Loss of Supply line uses an IVR which has the capability to automatically identify the location of a caller (where Energex recognises through Call Line Identification- CLI) and to provide specific outage advice to those callers. This automated IVR information positively satisfies a large proportion of the callers to the Loss of Supply line. Calls that proceed through the IVR are recorded and timed.

1.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Total number of calls received are calls to the loss of supply line.

1.3.2 Approach

Energex applied the following approach to obtain the required information:

1) Collation of daily reports for each relevant financial year
2) Applied the calculation of 20 percent of total calls abandoned to estimate the number of calls abandoned within 30 seconds
3) Calculation of estimates were applied where data was unavailable

1.4 Estimated Information

Energex applied the following estimates to obtain the required information of call data where data extracts were not available.

- During the 2010/11 to 2012/13 period, results for 'total number of calls received' were not able to be provided for a total of 90 days. A breakdown of the days per year is provided in Table 1.3 below. Data was unavailable on these days due to system errors causing partial loss of data for the affected days and is unable to be retrieved.

Table 1.3: Number of days where 'total number of calls received' figures unavailable

Year	Number of days
2010/11	14
2011/12	72
2012/13	4
Total	**90**

- During the 2011/12 period, results for the below could not be provided for all dates as daily extracts were not obtained;
  - 'Total number of calls received less calls to payment lines and automated interactive services';
  - Total calls abandoned; and
  - Calls to the fault line answered in 30 seconds.

When call data extracts have not been performed on a given date, within 60 days the data is purged from the source system (Telstra CCA) and is no longer available.

1.4.1.1 Justification for estimates

It was necessary to estimate the above information as it is not possible to obtain the data elsewhere.

1.4.1.2 Basis for estimates

1) Where results for 'total number of calls received' were not able to be provided, Energex used an apportionment approach. That is, where 'total number of calls received' data is not available, Energex applied the average percent of calls not transferred from automated interactive services (IVR) for the given month to the known calls transferred on each given day to estimate the total calls received.

   For example:

In July 2012, the average percent of calls satisfied in IVR was 55% (for the days that data was available). This percent was then applied to calls transferred from the IVR to estimate 'total number of calls received'.

2) Although not all daily information is available, Energex has access to monthly data extracts (obtained from Telstra CCA) which details call volumes transferred from the IVR, calls answered within 30 seconds and calls abandoned. Energex subtracted the total calls received, calls abandoned and calls answered within 30 seconds reported in each available daily extract from the total shown within the monthly extract. This calculation resulted in the volumes to be apportioned across the days where no data extracts were obtained.

   For example:

   The total of daily extracts available in July 2010 was 9,052. This was then subtracted from the monthly extract which reported 9,748 calls resulting in a total of 696 calls to be apportioned across a total of three days where data was not available.

Calls received less calls to payment lines and automated interactive services

3) The volume of calls received (determined from the calculation in step 2) was applied to the 'total number of calls received' (obtained from iReport) for each of the missing days, to obtain a percentage of calls that transferred from the IVR. This percentage could then be applied to each given days 'total calls received' to fairly distribute the volumes to be apportioned.

   For example:

   The total of calls received (obtained from iReport) for all three days where data was missing was 1,571. The 696 calls calculated in step 2 were then applied to this total to obtain a percent of calls that transferred from the IVR (44%). This percent was then applied to each of the three days 'total of calls received' to obtain estimates for each day.

Total calls abandoned

4) The volume of calls abandoned was calculated by obtaining the proportion of 'total calls received' (obtained from iReport) for each of the days where data extracts were not available. Energex could then apply this percentage to the total volume of calls abandoned calculated in step 2.

   For example:

   Estimated calls received for 24 July, 2010 was 136. This was then applied to the total of calls received for each of the three days where data was not available (1,571) to determine what percent of calls were received on the 24 July as a proportion of the all calls. This percent was then applied to the total calls abandoned calculated in step 2 (32) resulting in a total of six (6) calls.

Calls answered in 30 seconds

5) Energex applied the percentage of calls answered within 30 seconds (using the calculations performed in step 2) to the calculation of ‘calls received less calls to payment lines and automated interactive services’ performed in step 3.

   For example:

   A total of 632 calls were answered in 30 seconds calculated in step 2. This was then applied to the total calls received (696) to give a percent of calls answered within 30 seconds (90.8%). This percent was then applied to the total calls received calculated in step 3 which for 24 July, 2010 gave an estimate of 123.

The above approach has been used as it represents a fair and valid calculation for those occasions where call data cannot be obtained.

2 BoP 6.2.1 – Reliability and Customer Service - Reliability

The AER requires Energex to provide the following information relating to Table 6.2.1 - Unplanned minutes off supply (SAIDI) - Actual, target and proposed reliability:

For each year in the period 2009/10 to 2013/14, split by feeder category

- **Total actual sustained minutes off supply**
- **Total actual value of excluded events**
- **Total actual sustained minutes off supply after removing excluded events**

The AER requires Energex to provide the following information relating to Table 6.2.2 - Unplanned interruptions to supply (SAIFI) - Actual, target and proposed reliability:

For each year in the period 2009/10 to 2013/14, split by feeder category

- **Total actual sustained customer interruptions**
- **Total actual value of excluded events**
- **Total actual sustained customer interruptions after removing excluded events**

The AER requires Energex to provide the following information relating to Table 6.2.4 – Customer Numbers:

- **Customer number actuals for each year in the period 2009/10 to 2013/14, split by feeder category.**

Actual recorded information was provided for all components of submitted data.

These variables are a part of Regulatory Template 6.2 – Reliability and Customer Service.

This Basis of Preparation excludes Table 6.2.5 – Customer Services which is covered in a Basis of Preparation 6.2.2.

2.1 Consistency with Reset RIN Requirements

Table 2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 2.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
This regulatory template requires the input of performance actuals under the STPIS.	Provided in tables 6.2.1 and 6.2.2
DNSPs should insert "n/a" against parameters which do not apply to it. Do not delete inapplicable fields. DNSPs should add parameters where appropriate, if not included in the examples. Insert rows as required to accommodate this.	Energex does not report against 'long rural' parameters. "n/a" has been inserted in these fields. No additional parameters were added.

Requirements (instructions and definitions)	Consistency with requirements
Definitions must be provided in the relevant fields for all additional parameters.	
If parts of this template are unsuitable to record any of the requested information, the DNSP must provide this information in an alternative format, within its accompanying regulatory proposal and indicate the section of the regulatory proposal containing the information in the 'addressed at chapter/section of regulatory proposal' column.	No elements of the template were unsuitable to record the requested information.
The DNSP must provide detail of historical unplanned minutes off supply, unplanned interruptions, and customer numbers in accordance with tables 6.2.1, 6.2.2, and 6.2.4.	This information has been provided in the relevant tables.
Definitions of parameters under the AER's STPIS apply.	Definitions of parameters under the AER's STPIS have been applied.
Where exclusions apply, data provided below must exclude all events outlined under clause 3.3 of the AER's STPIS.	Where exclusions apply, data in tables 6.2.1 and 6.2.2 excludes all events outlined under clause 3.3 of the AER's STPIS.
SAIDI (System Average Interruption Duration Index) is the sum of the duration of each unplanned sustained Customer interruption (in minutes) divided by the total number of Distribution Category Customers. SAIDI excludes momentary interruptions (interruptions of one minute or less)."	This definition has been applied in table 6.2.1
SAIFI (System Average Interruption Frequency Index) is the total number of unplanned sustained Customer interruptions divided by the total number of Distribution Category Customers. Unplanned SAIFI excludes momentary interruptions (interruptions of one minute or less).	This definition has been applied in table 6.2.2
Asset customers are the averaged customer base using the customers on the first and last days of the reporting period are required for the calculation of SAIDI and SAIFI.	This definition has been applied to 2013/14 data only. Previous data reported applied a running average or monthly averages to produce similar results. Years utilising this alternate method have been audited and submitted for AER STPIS submissions for years 2010 to 2013.

Actual information was provided for:

- Table 6.2.1 – Actual outage data by category was used for the completion of the SAIDI "Actual" section of table for financial years 2010-2014.
- Table 6.2.2 - Actual outage data by category was used for the completion of the SAIFI "Actual" section of table for financial years 2010-2014.
- Table 6.2.4 - Actual Customer Number data by category was used for the completion of the Customer numbers "Actual" section of table for financial years 2010-2014.

2.2 Sources

Table 2.2 below sets out the sources from which Energex obtained the required information.

Table 2.2: Information sources

Variable	Source
Outages from 01/07/2009 to 25/05/2014 inclusive.	NFM NO (Network Facilities Management – Network Outage system)
Single loss events from 01/07/2009 to 30/06/2012.	SCM (Single loss of supply)
Single loss events for 01/07/2012 to 25/05/2014 inclusive.	EPM (Energex Performance Management)
Outages from 25/05/2014 to 30/06/2014 inclusive.	PON OMS (Power On, Outage Management System)
Regulatory customer base from 01/07/2009 to 30/06/2014	NFM (Asset Data)

2.3 Methodology

- Energex records outage data in sources listed in Table 2.2. The sources listed maintain customer interruption data in accordance with STPIS regulatory requirements.
- For the purposes of reporting Energex queries these source systems obtaining customer interruption data and regulatory customer bases by feeder category.

These sources are used to provide actual performance data for Tables 6.2.1, 6.2.2 and 6.2.4.

2.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Energex does not currently have any long rural feeders defined as those feeders in excess of 200km long and a maximum demand less than 0.3MVA/Km. Long rural data fields have n/a applied.
- Where available previously submitted AER regulatory submissions were used in the provision of historical data including actual category performance values for SAIDI and SAIFI.

2.3.2 Approach

For completion of Template 6.2 Energex used a combination of historical AER RIN data as listed below for financial years 2009/10 to 2012/2013 and Annual RIN data queried from sources listed in table 1.2 for financial year 2013/2014.

Energex applied the following approach to obtain the required information for actual years in tables 6.2.1, 6.2.2, and 6.2.4:

1) Data supplied by the 2009/10 – STPIS Trial spreadsheet which combined outage data and customer data by feeder category.
    a. Accuracy and completeness independently assessed by PB Audit report – (2159393A-REP-001-APP-001-Final-Combined.pdf).
2) Data supplied by the 2010/11 Annual RIN submission which combined outage data and customer data by feeder category.
    a. Accuracy and completeness independently assessed by PB Audit report – (2159393A-REP-001-APP-001-Final-Combined.pdf).
3) Data supplied by the 2011/12 Annual RIN submission which combined outage data and customer data by feeder category.
    a. Accuracy and completeness independently assessed by Audit report – (2175054A Energex RIN audit non-financial FINAL v1-0.pdf).
4) Data supplied by the 2012/13 Annual RIN submission which combined outage data and customer data by feeder category.
    a. Accuracy and completeness assessed by Audit report 2193354A-SC-RPT-002 RevD STPIS - FINAL.pdf.
5) Data supplied by the current 2013/14 Annual RIN submission which combined outage data and customer data by feeder category. It is considered as actual as it is

obtained from actual sources listed in table 1.2 even though there is no audit reference at this point.

a. The customer base applied to this financial year is fully compliant with the AER mandated method of; feeder category customers on the first and last day of the reporting period, averaged.

2.4 Estimated Information

No estimates were reported.

3 BoP 6.2.2 – Reliability and Customer Service - Service

The AER requires Energex to provide the following information relating to Table 6.2.5 – Customer Service:

For each year in the period 2009/10 to 2013/14

- **Number of Calls Received**
- **Number of calls answered within 30 seconds**
- **Percentage of Calls answered within 30 seconds**

These variables are a part of worksheet 6.2 – Reliability and Customer Service.

Actual information was provided for

- **Total number of calls received**
- **Calls to the fault line answered in 30 seconds**

Estimated information was provided for the above metrics on days where data extracts were not available.

These variables are a part of Regulatory Template 6.2 – Reliability and Customer Service.

This Basis of Preparation excludes Table 6.2.1, 6.2.2 and 6.2.4 which are covered in a Basis of Preparation 6.2.1.

3.1 Consistency with Reset RIN Requirements

Table 3.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The DNSP must provide detail of historical unplanned minutes off supply, unplanned interruptions, momentary interruptions, customer numbers and customer service in accordance with tables 6.2.1, 6.2.2, and 6.2.3. 6.2.4 and 6.2.5. Definitions of parameters under the AER's STPIS apply. Where exclusions apply, data provided below must exclude all events outlined under clause 3.3 of the AER's STPIS.	Data provided in Reset RIN table 6.2.5 has been input in accordance with this requirement and is therefore excludes data for Major Event Days (MEDs) per clause 3.3 (b) of the AER’s STPIS.
The AER's definition of calls answered within 30 seconds is as follows: Calls to the fault line answered in 30 seconds where the time to answer a call is measured from when the call enters the telephone system of the call centre (including that time when it may be ringing unanswered	Data provided is consistent with this definition.

Requirements (instructions and definitions)	Consistency with requirements
by any response) and the caller speaks with a human operator, but excluding the time that the caller is connected to an automated interactive service that provides substantive information. This measure does not apply to: – calls to payment lines and automated interactive services; – calls abandoned by the customer within 30 seconds of the call being queued for response by a human operator. Where the time in which a telephone call is abandoned is not measured, then an estimate of the number of calls abandoned within 30 seconds will be determined by taking 20 per cent of all calls abandoned. Note: Being placed in a queuing system (automated or otherwise) does not constitute a response. 'Calls answered within 30 seconds' and 'Calls received' should be calculated excluding calls abandoned within 30 seconds of being queued for a human operator; and calls to payment lines and automated interactive services.	

Actual information was provided for

- Total number of calls received
- Calls to the fault line answered in 30 seconds

Estimated information was provided for the above metrics on days where data extracts were not available.

3.2 Sources

Table 3.2 below sets out the sources from which Energex obtained the required information.

Table 3.2: Information sources

Variable	Source
Total number of calls received	iReport
Calls to the fault line answered in 30 seconds	Telstra Call Centre Analyser (CCA)
Identification of Major Event Days (dates) for exclusion	EPM

3.3 Methodology

- Energex utilises a hosted telephone service provided by Telstra. This Genesys system is provided and supported by Telstra and has been in place at Energex since 2005. All phone calls received by Energex are handled by the Genesys system. The Genesys system incorporates a reporting tool named Call Centre Analyser (CCA). CCA is used to provide daily statistics on phone calls including total number of calls and number of calls answered in 30 seconds.
- Energex has a number of phone numbers including a Loss of Supply line, Emergency line and General Enquiry Line. In accordance with the specification, calls reported are calls to the Loss of Supply line. The Loss of Supply line uses an IVR which has the capability to automatically identify the location of a caller (where Energex recognises through Call Line Identification- CLI) and to provide specific outage advice to those callers. This automated IVR information positively satisfies a large proportion of the callers to the Loss of Supply line. Calls that proceed through the IVR are recorded and timed.
- Calls that are received on MED days are deducted from the total call count to report the 'Total number of calls' and 'Number of calls answered within 30 seconds' with exclusions.

3.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- Total number of calls received are calls to the loss of supply line

3.3.2 Approach

Energex applied the following approach to obtain the required information:

1) Collation of daily reports for each relevant financial year
2) Identification of MED dates to be excluded from total call count
3) Applied the calculation of 20 percent of total calls abandoned to estimate the number of calls abandoned within 30 seconds
4) Calculation of estimates were applied where data was unavailable

3.4 Estimated Information

Energex applied the following estimates to obtain the required information of call data where data extracts were not available.

- During the 2010/11 to 2012/13 period, results for 'total number of calls received' were not able to be provided for a total of 90 days. A breakdown of the days per year is provided in Table 3.3. Data was unavailable on these days due to system errors causing partial loss of data for the affected days and is unable to be retrieved.

Table 3.3: Number of days where 'total number of calls received' figures unavailable

Year	Number of days
2010/11	14
2011/12	72
2012/13	4
Total	**90**

- During the 2011/12 period, results for the below could not be provided for all dates as daily extracts were not obtained;
  - 'Total number of calls received less calls to payment lines and automated interactive services'
  - Total calls abandoned
  - Calls to the fault line answered in 30 seconds

When call data extracts have not been performed on a given date, within 60 days the data is purged from the source system (Telstra CCA) and is no longer available.

3.4.1 Justification for Estimated Information

It was necessary to estimate the above information as it is not possible to obtain the data elsewhere.

3.4.2 Basis for Estimated Information

1) Where results for 'total number of calls received' were not able to be provided, Energex used an apportionment approach. That is, where 'total number of calls received' data is not available, Energex applied the average percent of calls not transferred from automated interactive services (IVR) for the given month to the known calls transferred on each given day to estimate the total calls received.

   For example:

   In July 2012, the average percent of calls satisfied in IVR was 55% (for the days that data was available). This percent was then applied to calls transferred from the IVR to estimate 'total number of calls received'.

2) Although not all daily information is available, Energex has access to monthly data extracts (obtained from Telstra CCA) which details call volumes transferred from the IVR, calls answered within 30 seconds and calls abandoned. Energex subtracted

the total calls received, calls abandoned and calls answered within 30 seconds reported in each available daily extract from the total shown within the monthly extract. This calculation resulted in the volumes to be apportioned across the days where no data extracts were obtained.

For example:

The total of daily extracts available in July 2010 was 9,052. This was then subtracted from the monthly extract which reported 9,748 calls resulting in a total of 696 calls to be apportioned across a total of three days where data was not available.

Calls received less calls to payment lines and automated interactive services

3) The volume of calls received (determined from the calculation in step 2) was applied to the ‘total number of calls received’ (obtained from iReport) for each of the missing days, to obtain a percentage of calls that transferred from the IVR. This percentage could then be applied to each given days ‘total calls received’ to fairly distribute the volumes to be apportioned.

   For example:

   The total of calls received (obtained from iReport) for all three days where data was missing was 1,571. The 696 calls calculated in step 2 were then applied to this total to obtain a percent of calls that transferred from the IVR (44%). This percent was then applied to each of the three days ‘total of calls received’ to obtain estimates for each day.

Total calls abandoned

4) The volume of calls abandoned was calculated by obtaining the proportion of ‘total calls received’ (obtained from iReport) for each of the days where data extracts were not available. Energex could then apply this percentage to the total volume of calls abandoned calculated in step 2.

   For example:

   Estimated calls received for 24 July, 2010 was 136. This was then applied to the total of calls received for each of the three days where data was not available (1,571) to determine what percent of calls were received on the 24 July as a proportion of the all calls. This percent was then applied to the total calls abandoned calculated in step 2 (32) resulting in a total of six (6) calls.

Calls answered in 30 seconds

5) Energex applied the percentage of calls answered within 30 seconds (using the calculations performed in step 2) to the calculation of ‘calls received less calls to payment lines and automated interactive services’ performed in step 3.

   For example:

A total of 632 calls were answered in 30 seconds calculated in step 2. This was then applied to the total calls received (696) to give a percent of calls answered within 30 seconds (90.8%). This percent was then applied to the total calls received calculated in step 3 which for 24 July, 2010 gave an estimate of 123.

The above approach has been used as it represents a fair and valid calculation for those occasions where call data cannot be obtained.

4 BoP 6.3.1– Sustained Interruptions

The AER requires Energex to provide the following information relating to Table 6.3.1:

- **Sustained Interruptions to Supply (from 01 July 2013 to 30 June 2014)**

Actual Data was provided for all but four outages.

Estimated Data was provided for four outages as detailed in section 1.1.6 – Estimates

These variables are a part of Regulatory Template 6.3 – Sustained Interruptions.

4.1 Consistency with Reset RIN Requirements

Table 4.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 4.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Sustained interruption data by Asset Category must be reported against the “Reason for Interruption” outage cause table in CA RIN sheet 6.3 Sustained Interruptions. This data is inclusive of planned events.	Reporting uses actual recorded outage data (excluding estimates – refer to section 4.4) and is in accordance with this template.
SAIDI (System Average Interruption Duration Index) is the sum of the duration of each unplanned sustained Customer interruption (in minutes) divided by the total number of Distribution Customers. SAIDI excludes momentary interruptions (interruptions of one minute or less).	SAIDI provided in accordance with this requirement.
SAIFI (System Average Interruption Frequency Index) is the total number of unplanned sustained Customer interruptions divided by the total number of Distribution Customers. Unplanned SAIFI excludes momentary interruptions (interruptions of one minute or less).	SAIFI provided in accordance with this requirement.
Asset customers by category calculated in accordance with the AER method of an averaged customer base using the customers on the first and last days of the reporting period are required for the calculation of SAIDI and SAIFI.	Asset customers summed by category comply with the AER mandated method.
The MED status of each sustained event must be identified in table 6.3.1	The MED status for each day is included against all events. The AER mandated 2.5 Beta

Requirements (instructions and definitions)	Consistency with requirements
	method has been used in the determination MED's for current year.

Estimated information was provided for four outages that didn't have a cause allocated. These outages are listed in section 4.4 Estimated Information.

Estimated cause of GN-NR "No Cause Reported" was also applied to the single loss outages from EPM prior to 25 May 2014.

Actual information was provided for all other outage data.

4.2 Sources

Table 4.2 below sets out the sources from which Energex obtained the required information.

Table 4.2: Information sources

Variable	Source
NFM NO (Network Facilities Management – Network Outage system) for outages from 01/07/2013 to 25/05/2014 inclusive.	NFM
NFM (Asset Data) – For Regulatory customer base as at 01/07/2013 and 30/06/2014.	NFM
NFM (Asset Data) – For Feeder identifier applied to 6023 Single Loss of Supply records.	NFM
EPM (Energex Performance Management) – Single loss data sourced for 01/07/2013 to 25/05/2014 inclusive.	EPM
PON OMS (Power On, Outage Management System) Outages from 25/05/2014 to 30/06/2014 inclusive.	PON

4.3 Methodology

Energex utilised data in outage recording systems as listed in Table 4.2 to populate the Sustained Interruptions template 6.3. Data was compiled from individual transformer records that detailed customers interrupted and the duration of these interruptions.

Grouping outage data by category, cause, outage level and voltage level; Energex calculated SAIDI and SAIFI using CML (Customer Minutes Lost) and CI (Customers Interrupted) with customer numbers to populate template 6.3 Sustained Interruptions.

4.3.1 Assumptions

Energex applied the following assumptions to obtain the required figures:

- In classifying each asset failure Energex did interpret the cause table "Reason for interruption" and "Detailed reason for interruption" and cross referenced these criteria to the Energex outage cause codes in use.
- In mapping cause codes used by Energex to the AER cause table there were a number second tier AER "Detailed reason for interruption" causes that had no equivalent to reporting systems used by Energex. These detailed causes were:
  - Animal - Animal nesting/burrowing, etc and other.
  - Animal – Other
  - Vegetation – Grow-in-Other responsible party
- For single loss events prior to 25/05/2014 Energex did not attribute a cause as used by NFM NO. In these instances a NFM cause code of "No Cause reported" (GN-NR) was allocated. This resulted in a CM_REASON code of "Other" and a CM_DETAIL_REASOM of "Unknown".
- For column "J" of table 6.3.1 (Average duration of sustained customer interruption) Energex has calculated this duration as the Customer Minutes Lost (CML) amount over the Customers Impacted (CI) figure. This is also consistent with the measure CAIDI which is SAIDI/SAIFI.
- Unplanned sustained transformer outages with a valid outage report number but no valid feeder and therefore category are excluded from the submitted data. There are 276 transformers on this list. This equated to a CML of 76111 and customer count value of 1271. Represented as a system SAIDI and SAIFI value as below:
  - SYSTEM SAIDI = 0.056 minutes
  - SYSTEM SAIFI = 0.000938 interruptions
  - The unallocated system SAIDI and SAIFI as a percentage for normalised data (Excluding excluded outages) is represented below:
  - SAIDI – 0.056/70.04 = 0.08%
  - SAIFI – 0.0009/0.893 = 0.1%

4.3.2 Approach

Energex applied the following approach to obtain the required information:

1) Energex queried the network outage management system (NFM), The newly introduced outage management system PON OMS and the corporate reporting system EPM to obtain a listing of sustained outages greater than one minute. These were then grouped by outage report ID, Feeder, and Category. This transformer listing was filtered for Single Loss codes that are not applicable to reporting so only forced outages with a customer impact were included. From this listing data was grouped by Outage ID, Category, and Feeder to produce a consolidated list of outages being 20254. This consolidated list was then used to apply against the AER cause groupings to match AER 6.3 template.

2) The "Reason for interruption" and "Detailed reason for interruption" fields were mapped to the Energex cause codes used in the network outage system NFM which facilitated a complete representation of all NFM, PON and EPM single loss outages against AER reason and detail reason fields except for the three detailed reasons mentioned in section 4.3.1 above.

3) The outage statistics associated with these asset details were calculated as below:
    a. Number of customers affected – This was a distinct count of customers impacted by each asset outage.
    b. Average duration of interruption – This was the Customer minutes lost/Customers affected.
    c. SAIDI – The Customer Minutes Lost (CML) for each asset interruption was place over the asset category customer base.
        i. SAIDI = CML/Asset category customer
    d. SAIFI – The distinct count of customers for each asset interruption was placed over the asset category customer base.
        i. SAIFI = Customers affected/Asset category customer base

4) The MED field was updated in accordance with the Energex NFM Outage Exception table which details those days that were deemed to be MED's.
    a. Energex has for the Submission RIN performed the 2.5 Beta calculation method to determine the appropriate threshold for daily system SAIDI. This annotated in the last column of the template.

4.4 Estimated Information

Table 4.3 provides details of outages which had no cause allocated. A “No Cause Reported” code of GN-NR was applied in these instances:

Table 4.3: Outages with no cause allocated

tblCA_RIN_Combined				
DATE_SH	**TIME_SH**	**OUTAGE_REPORT_SUN**	**OPERTN_ID**	**FEEDER_CATEGORY**
30/06/2014	16:19	INCD-6061-g	GYGGYS6	RURAL
30/06/2014	08:46	INCD-5890-g	RWD1	RURAL
20/06/2014	17:48	INCD-4165-g	NVL3	URBAN
27/05/2014	08:36	INCD-914-h	TWT12A	RURAL

For single loss events prior to 25/05/2014 Energex did not attribute a cause as used by NFM NO. In these instances a NFM cause code of “No Cause reported” (GN-NR) was allocated.

4.4.1 Justification for Estimated Information

Inclusion of these outages under an assumed cause will enable their contribution to the overall system SAIDI result.

5 BoP 6.4.1– Historical MEDs

The AER requires Energex to provide the following information relating to Table 6.4.1 – Major Event Days:

- **Historical daily performance for the period 01/07/2004 to 30/06/2012**

Actual information was provided for all data.

These variables are a part of Regulatory Template 6.4 – Historical MEDs.

5.1 Consistency with Reset RIN Requirements

Table 5.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 5.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
This regulatory template requires the input of historical daily performance data for the calculation of the major event day (MED) boundaries for the regulatory years 2009-10 to 2013-14.	Refer to Regulatory Template
The following data is required to calculate the MED boundary: - daily unplanned SAIDI over five sequential regulatory years ending on the last day of the last complete reporting period	Refer to Regulatory Template
These values should reflect any exclusions permitted under clause 3.3(a) and 5.4 of the scheme.	Values reflect exclusions permitted under clause 3.3(a) and 5.4 of the scheme.
SAIDI (System Average Interruption Duration Index) is the sum of the duration of each unplanned sustained Customer interruption (in minutes) divided by the total number of Distribution Category Customers. SAIDI excludes momentary interruptions (interruptions of one minute or less).”	This definition was applied to table 6.4.1

Actual information was provided for System SAIDI for the specified dates.

5.2 Sources

Table 5.2 over page sets out the sources from which Energex obtained the required information.

Table 5.2: Information sources

Variable	Source
For outages from 01/07/2004 to 30/06/2012.	NFM NO (Network Facilities Management – Network Outage system)
Single loss events from 01/07/2004 to 30/06/2012.	SCM (Single loss of supply)

5.3 Methodology

Energex utilised previously audited and submitted RIN data developed from the above sources to satisfy this requirement.

5.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- If days during the reporting period had no System SAIDI the field is left blank.

5.3.2 Approach

Energex used the following approach to populate the MED system SAIDI:

1) For dates between 01/07/2005 to 30/06/2012 previously submitted Economic benchmarking submission for 2013 financial year was used.

2) For dates between 01/07/2004 and 30/06/2005 the MED calculation used for the 2011 AER RIN submission was used.

These previously submitted and audited documents were generated from sources listed in Table 5.2 above.

5.4 Estimated Information

No estimates were provided.

Energex

Reset RIN

Basis of Preparation

7. Revenue, Schemes and Prices

October 2014

energex

positive energy

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the fast growing region of South East Queensland. Energex provides distribution services to almost 1.4 million connections, delivering electricity to 2.8 million residents and businesses across the region.

Energex's key focus is distributing safe, reliable and affordable electricity in a commercially balanced way that provides value for its customers, manages risk and builds a sustainable future.

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Section 7 – Revenue, Schemes and Prices

1 BoP 7.4.1 – Shared Assets

The AER requires Energex to provide the following information relating to table 7.4.1 - Total unregulated revenue earned with shared assets ($'000 nominal):

Shared asset unregulated revenue for each regulatory year in the 2005/06 to 2013/14 period per the shared asset unregulated service providing the following:

- **Name of shared asset unregulated service**
- **Descriptions of shared assets used to provide the service**
- **unregulated revenue amount**

The AER requires Energex to provide the following information relating to table 7.4.2 – Shared asset unregulated services - apportionment methodology:

- **Name of shared asset unregulated service for which revenues were apportioned**
- **Apportionment methodology**

Estimated data was provided for the period 2005/06 to 2007/08. All other information reported is actual.

These variables are a part of Regulatory Template 7.4 – Shared Assets

1.1 Consistency with Reset RIN Requirements

Table 1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 1.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Provide Energex's shared assets information in regulatory template 7.4.	Shared Asset information has been provided in table 7.4.1
Shared asset unregulated revenue: Revenue earned by charging for unregulated services provided with *shared assets*. In some circumstances this may reflect revenue apportionment in line with the AER's Shared Asset Guideline.	Revenue amounts reported in table 7.4.1 has been provided in accordance with this definition
Shared asset unregulated services: Unregulated services provided, in part or in whole, by use of *shared assets*.	Services reported in table 7.4.1 are in line with this definition.
Shared assets: Assets used to provide both standard control services and unregulated services.	Shared assets described in table 7.4.1 are in line with this definition.

Requirements (instructions and definitions)	Consistency with requirements
Apportionment: The allocation of unregulated revenues reflecting the proportionate use of the shared asset, in line with the AER's Shared Asset Guideline.	Energex did not apply an apportionment method.

Actual information was provided for the period 2008/09 to 2013/14, whilst estimated information was provided for the period 2005/06 to 2007/08.

1.2 Sources

Table 1.2 below sets out the sources from which Energex obtained the required information.

Table 1.2: Information sources

Variable	Source
License fee for use of Energex electricity distribution network assets ($000's): 2005/06 to 2007/08	*Energex Shared Assets Manager*
License fee for use of Energex electricity distribution network assets ($000's): 2008/09 to 2013/14	*EPM – FIN032 Divisional Profit and Loss*

1.3 Methodology

1.3.1 Assumptions

- Although all revenue data for the reported years was obtained via Shared Assets Manager, information reported for the 2005/06 and 2007/08 regulatory years is assumed to be estimated data given that changes in systems utilised to capture this information prevent Energex from reconciling/validating this information in the Energex Performance Management (EPM) system.
- For the 2008/09 to 2013/14 regulatory years, information has been reconciled to EPM figures.

1.3.2 Approach

Energex applied the following approach to obtain the required information:

- Data for the years 2008/09 to 2013/14 was directly sourced from EPM reports. Data for the 2005/06 to 2007/08 years was sourced from Energex Shared Assets Manager without any adjustment.

1.4 Estimated Information

- Energex has used estimated data for the period 2005/06 to 2007/08 which is based on information provided by the Shared Asset Manager.

1.4.1 Justification for Estimated Information

- Information reported for the 2005/06 and 2007/08 regulatory years has been considered estimated given that changes in systems utilised to capture this information prevent Energex from reconciling/validating this information in the Energex Performance Management (EPM) system.

1.4.2 Basis for Estimated Information

- The estimates are based on historical actual information kept by Energex Shared Assets Manager.

2 BoP 7.5.1 – EBSS

The AER requires Energex to provide the following variables relating to Table 7.5.1 - The carryover amounts that arise from applying the EBSS during the 2010-11 to 2014-15 regulatory control period

Populate all input cells (yellow) in table 7.5.1.

Efficiency gains are calculated using the formulae below. Adjusted target and actual amounts are used to calculate the carry-over amounts.

For the first application of the scheme, the efficiency carry forward amount for the first year of the regulatory period is expressed mathematically as:

- **E1 = F1 – A1 where A1 is the actual operating cost for year 1 and F1 is the regulatory target operating cost for that year.**

For savings that arose in the second to fifth year of the regulatory period, the efficiency carry forward amount is calculated as:

- **Et = (Ft – At) – (Ft-1 – At-1), where: Et is the efficiency benefit/loss in year t;**
- **At, At-1 is the actual operating cost for the years t and t-1 respectively; and**
- **Ft, Ft-1 is the forecast operating cost for the years t and t-1 respectively**

Because the revenue determination will occur prior to the completion of the current period, opex for the final year will be estimated as follows:

- **A5 = F5 – (F4 – A4)**

Actual information was provided for all variables in the 2010/11 to 2013/14 regulatory years.

These variables are a part of Regulatory Template 7.5 – EBSS

2.1 Consistency with Reset RIN Requirements

Table 2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 2.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
To calculate the carryover amounts that arise from applying the efficiency benefit sharing scheme during Energex's current regulatory control period: (a) provide the forecast and actual operating expenditure amounts in regulatory template 7.5;	The forecast and actual expenditure has been included per the AER's instructions in the RIN template. For further details refer to the methodology section.
(b) identify all changes to Energex's Capitalisation Policy during the	Nil capitalisation policy changes for forecast and

Requirements (instructions and definitions)	Consistency with requirements
current regulatory control period.	actual expenditure have been identified.
For each change identified in the response to paragraph 22.1(b): (a) state, if any, the financial impact of the change; (b) state the reasons for the change; (c) explain the effect of the change, if any, on the forecast operating expenditure for each year of Energex's current regulatory control period; and (d) explain the effect of the change, if any, on the actual operating expenditure for each year of Energex’s current regulatory control period.	Nil capitalisation policy changes for the current regulatory control period have been identified. As a result, no demonstration in response to section 22.1(b) required.
For the purposes of applying the efficiency benefit sharing scheme: (a) identify all cost categories proposed to be excluded from the operation of the efficiency benefit sharing scheme; (b) explain for each cost category identified in the response to paragraph 22.3(a) the reasons for the proposed exclusion.	No exclusions proposed.

2.2 Sources

Table 2.2 below sets out the sources from which Energex obtained the required information.

Table 2.2: Information sources

Variable	Source
Table 7.5.1- Opex allowance applicable to EBSS (EBSS target)	Queensland Distribution Determination 2010-11 to 2014-15 (May 2010).
Table 7.5.1- Actual and estimated opex applicable to EBSS	Actual opex applicable to EBSS is as reported in the Energex Annual Performance RINs for the years 2010-11 to 2013-14, originally soured from

Variable	Source
	Ellipse (GL).

2.3 Methodology

Information provided in the RIN template 7.5 EBSS is based on data in the Queensland Distribution Determination, Annual Performance RINs and the Proposed Determination.

2.3.1 Assumptions

No Assumptions were made.

2.3.2 Approach

Energex applied the following approach to obtain the required actual information:

- Data was obtained from the Energex Annual Regulatory Accounts.
- Operational expenditure was classified as expenditure applicable to EBSS and approved excluded expenditure as per the 2010-15 determination.

The following opex cost categories were proposed and accepted as exclusions for the current regulatory control period (refer chapter 13, final distribution determination):

- debt raising costs;
- insurance and self-insurance costs;
- superannuation costs for defined benefit fund members; and
- non-network alternatives.

Energex is seeking approval of additional adjustments to its actual opex for EBSS purposes prior to determining the carryovers, to ensure that the scheme operates as it was intended. These are:

- service line inspection costs in 2011-12 incurred due to a serious manufacturing fault
- the incremental costs of both the 2011 flood event and ex-tropical cyclone Oswald
- a greater share of support costs being allocated to opex due to the change in the opex-capex proportions resulting from the lower program of work.

These additional adjustments have been reported in RIN template 7.5 - Table 7.5.1 as Specific Uncontrollable Costs as summarised in Table 2.3 over page:

Table 2.3: Specific Uncontrollable costs

	10/11	11/12	12/13	13/14
Specific uncontrollable costs reported by NSP ($million, nominal):	**25.6**	**16.6**	**27.8**	**23.2**
Jan 2011 Floods	17.0			
Cyclone Oswald incremental costs			11.2	
Overhead reallocation - reduced CAPEX Program	8.6	16.6	16.6	23.2

2.4 Estimated Information

No estimates were used.

2.5 Explanatory notes

Notes on actual excludable costs

- The most significant predetermined excluded costs are the solar PV feed-in tariff costs, which are a nominated pass through event. The increase in Solar PV Feed-in-Tariff Payments when compared to the determination allowance is due to an increased number of solar PV connections, resulting in higher levels of energy being exported back to the grid and a corresponding increase in feed-in tariff payments.

- While $17 million of incremental opex costs were incurred due to the 2011 flood event, Energex decided not to seek a pass through as an act of good will and in recognition that many customers had incurred personal loss. The AER indicated that a decision regarding the exclusion of the incremental flood costs would be made as part of the next determination. Energex has applied the same rationale for excluding the incremental costs of $11 million associated with ex-tropical cyclone Oswald, noting that this event did not meet the materiality threshold to qualify for a pass through.

- Inspection costs of service lines in 2011-12 totalling approximately $26 million of the 2011-12 overspend was due service lines which were deteriorating due to a manufacturing defect, representing a safety risk to the public. The compensation of $12.8 million paid in 2013-14 (which is reported as revenue in 2013-14 annual RIN) approximately equated to the use of the provision; the net position being that Energex had not incurred any additional costs. Given this, Energex has removed the $16.8 million provision costs in 2011-12. No other provisions were considered as having a material impact on opex.

- Consistent with the application of Energex's CAM, the significant reduction in capex in the current regulatory control period has created a materially higher allocation of overhead costs to opex. While the pool of overhead costs has reduced, the allocation between opex and capex has changed due to the underlying proportion of opex and capex changing. Energex has adjusted for the impact of the higher proportion of overhead costs being allocated to opex such that the actual and forecast opex for EBSS purposes are prepared on the same basis consistent with the current regulatory determination.

3 BoP 7.7.1 – Services Indicative Prices

The AER requires Energex to provide the following information relating to Table 7.7.1 – Standard Control Services:

For each year in the period 2009/10 to 2013/14

- **Sales quantities;**
- **Revenue earned; and**
- **Current Prices**

Split by

- **Standard Control Service Category**
- **Tariff**
- **Tariff Component**
- **Description**

Actual information was provided for 2010/11 to 2013/14 and 2014/15 prices.

Estimated Information was provided for sales quantities for 2014/15 and all other forecast information.

These variables are a part of Regulatory Template 7.7 – Services, Indicative Prices

This Basis of Preparation excludes Table 7.7.2 – Negotiated Services which is not applicable for Energex.

3.1 Consistency with Reset RIN Requirements

Table 3.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.1: Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The DNSP must complete the following tables and provide an explanation in the regulatory proposal.	Refer to table 7.7.1 in the regulatory template and Chapter 23 of the regulatory proposal.
In table 7.1.1 the DNSP should insert the service category, tariff and tariff component title headings in columns C to E to match their own service categories. All prices should be provided on a GST exclusive basis.	Table 7.7.1 has been completed in accordance with these requirements and prices provide exclusive of GST.

Requirements (instructions and definitions)	Consistency with requirements
Standard control services are direct control services that are subject to a control mechanism based on a distribution Network Service Provider's total revenue requirement (as defined in the NER).	Services include in table 7.7.1 comply with this definition.

Actual information was provided for 2010/11 through to 2014/15 Tariff Prices.

3.2 Sources

The information was obtained from approved Energex Annual Pricing Proposals located on the AER website and the Energex PEACE database.

Table 3.2 below sets out the sources from which Energex obtained the required information.

Table 3.2: Information sources

Variable	Source
2010/11 AER Approved Annual Prices	Table 6.4 2010/11 AER Approved Annual Pricing Proposal:
2011/12 AER Approved Annual Prices	Table 6.4 2011/12 AER Approved Annual Pricing Proposal:
2012/13 AER Approved Annual Prices	Table 6.5 2012/13 AER Approved Annual Pricing Proposal:
2013/14 AER Approved Annual Prices	Table 4.2 AER Approved Annual Pricing Proposal
2014/15 AER Approved Annual Prices	Table 4.6 AER Approved Annual Pricing Proposal:
Sales quantities	PEACE Reports – FRC003A, FRC003B, FRC111, FRC123, FRC247 Detailed, FRC247 Summary, MSR296
Revenue Earned	PEACE Reports – FRC003A, FRC003B, FRC111, FRC123, FRC247 Detailed, FRC247 Summary, MSR296 and Regulatory Accounts

3.3 Methodology

- Historical prices were transposed from AER approved Pricing Proposals sourced from the AER website.
- Historically revenue data was collated by Energex in a Microsoft Access database in categories similar to what is required for the EB RIN. This database is used to report on the under/over-collection of revenue from customers.

3.3.1 Assumptions

No assumptions were made.

3.3.2 Approach

1) The following reports have been used for Regulatory Year 2014:
    a. FRC003A
    b. FRC003B
    c. FRC111
    d. FRC123
    e. FRC247 Detailed
    f. FRC247 Summary
    g. MSR296
2) These reports were then collated by the database and revenue transactions were output into excel, classified by tariff category and network tariff code, which allowed the sales quantities and revenue earned to be identified.
3) Data for prior years had already been collected for the previous EB RIN, and used the same methodology as above.
    a. The key variances seen in the data were individually addressed:
        i. To ensure the 2012 and 2013 figures reconciled back to the Regulatory Accounts, the STPIS Reward was added to the underlying figures sourced from PEACE in accordance with advice from the AER on 1st of April 2014. These adjustments of $30.5 million and $9.6 million respectively have been apportioned over all line items except DREV0113 and DREV0206.
        ii. Figures for years 2009 – 2012 showed variances to the Regulatory Accounts which are due to entries in the general ledger that are not in the PEACE reports, any manual adjustments that were made to the regulatory reports and any missing reports that were not included in the database. A pro-rata adjustment was made to all figures in these years to match what was stated in the regulatory reports.

4) In relation to the 2015 Regulatory Year the budget was inputted into the database and our estimates were collated using the same approach as above.

5) For the current prices and indicative prices the prices were transposed from the AER approved Pricing Proposals sourced from the AER website.

3.4 Estimated Information

- Figures for years 2009 – 2012 showed variances to the Regulatory Accounts which are due to entries in the general ledger that are not in the PEACE reports, any manual adjustments that were made to the regulatory reports and any missing reports that were not included in the database. A pro-rata adjustment was made to all figures in these years to match what was stated in the regulatory reports

- All data for the 2014/15 regulatory year is estimated information.

3.4.1 Justification for Estimated Information

- As we have not completed the 2014/15 regulatory year, budget data was used as an estimate.