Energex

Economic Benchmarking RIN

Basis of Preparation

2014-15

energex

positive energy

Energex Limited (Energex) is a Queensland Government Owned Corporation that builds, owns, operates and maintains the electricity distribution network in the growing region of South East Queensland. Energex provides distribution services to almost 1.4 million domestic and business connections, delivering electricity to a population base of around 3.2 million people.

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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3.0 Introductory Notes

The AER requires Energex to provide the Regulatory Templates attached at Appendix A of the Notice, completed in accordance with the AER's Notice and the instructions and definitions in the document attached at Appendix B of the Notice.

The Regulatory Templates included as Appendix A of the Economic Benchmarking Notice in November 2013 were modified and reissued in 2014. This revision resulted in changes to a number of the Regulatory Template, RIN table and Variable reference numbers.

The EB RIN Instructions and Definitions were not changed following this revision. Therefore the table references in the AER requirements section in this basis of preparation may differ to the actual table references included in Energex's response.

3.1 REVENUE

3.1.1 Revenue - Standard Control Services

The AER requires Energex to provide the following information relating Standard Control Service (SCS) revenue:

3.1.1. Revenue grouping by chargeable quantity

- **DREV0101 – Revenue from Fixed Customer Charges**
- **DREV0102 – Revenue from Energy Delivery charges where time of use is not a determinant**
- **DREV0103 – Revenue from On–Peak Energy Delivery charges**
- **DREV0104 – Revenue from Shoulder period Energy Delivery Charges**
- **DREV0105 – Revenue from Off–Peak Energy Delivery charges**
- **DREV0106 – Revenue from controlled load customer charges**
- **DREV0107 – Revenue from unmetered supplies**
- **DREV0108 – Revenue from Contracted Maximum Demand charges**
- **DREV0109 – Revenue from Measured Maximum Demand charges**
- **DREV0110 – Revenue from metering charges**
- **DREV0111 – Revenue from connection charges**
- **DREV0112 – Revenue from public lighting charges**
- **DREV0113 – Revenue from other Sources**
- **DREV01 – Total revenue by chargeable quantity**

3.1.2 Revenue grouping by Customer type or class

- **DREV0201 – Revenue from residential Customers**
- **DREV0202 – Revenue from non-residential customers not on demand tariffs**
- **DREV0203 – Revenue from non-residential low voltage demand tariff customers**
- **DREV0204 – Revenue from non-residential high voltage demand tariff customers**
- **DREV0205 – Revenue from unmetered supplies**
- **DREV0206 – Revenue from Other Customers**
- **DREV02 – Total revenue by customer class**

3.1.3 Revenue (penalties) allowed (deducted) through incentive schemes

- **DREV0301 – EBSS**
- **DREV0302 – STPIS**
- **DREV0303 – F-Factor**
- **DREV0304 – S.Factor True up**
- **DREV0305 – Other**
- **DREV03 - Total revenue of incentive schemes**

These variables are a part of Regulatory Template 3.1 – Revenue.

All information reported for 2014/15 is Actual Information.

3.1.1.1 Consistency with EB RIN Requirements

Table 3.1.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.1.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report revenues by chargeable quantity (RIN Table 3.1.1) and by customer class (RIN Table 3.1.2).	SCS revenue figures have been reported in line with the AERs requirements. Demonstrated in the methodology section.
The total of revenues by chargeable quantity must equal the total of revenues by customer class because they are simply two different ways of disaggregating revenue information.	Demonstrated in the section 3.1.1.3 (Methodology).
Energex must separately provide revenues received or deducted as a result of incentive schemes (RIN Table 3.1.3).	STPIS reported in RIN table 3.1.3 as per 2014/15 Pricing Proposal and assumed to be fully collected
Total revenues for Direct Control Services will equal those reported in the Regulatory Accounting Statements (with the exception of total revenue in RIN Table 3.1.3).	All figures for SCS revenue have been reconciled to the Regulatory Accounts.
Revenues reported must be allocated to the chargeable quantity that most closely reflects the basis upon which the revenue was charged by Energex to customers… …Revenues that cannot be allocated to the specific chargeable quantities in variables DREV0101 to DREV0112 must be reported against 'Revenue from other Sources' (DREV0113).	All SCS revenue was reported in the categories defined by the AER. No SCS revenue was reported against "Revenue from other sources"
Energex must allocate revenues to the customer type that most closely reflects the customers from which Energex received its revenue. Revenues that Energex cannot allocate to the customer types DREV0201–DREV0205 must be reported against 'Revenue from other Customers' (DREV0206).	All SCS revenue was reported in the categories defined by the AER.
Energex must report the penalties or rewards of incentive schemes in this table. The penalties or rewards from the schemes applied by previous	Energex recognises revenues and penalties from incentive schemes however no recoveries have been collected from

Requirements (instructions and definitions)	Consistency with requirements
jurisdictional regulators that are equivalent to the service target performance incentive scheme (STPIS) or efficiency benefit sharing scheme (EBSS) must be reported against the line items for those schemes."	customers to date.

3.1.1.2 Sources

Table 3.1.2, Table 3.1.3 and Table 3.1.4 below demonstrate the sources from which Energex obtained the required information:

Table 3.1.2: Data Sources – RIN Table 3.1.1: Revenue Grouping by Chargeable Quantity

Variable Code	Variable	Unit	Source
DREV0101	Revenue from Fixed Customer Charges	$0's	PEACE/Regulatory Accounts
DREV0102	Revenue from Energy Delivery charges where time of use is not a determinant	$0's	PEACE/Regulatory Accounts
DREV0103	Revenue from On–Peak Energy Delivery charges	$0's	PEACE/Regulatory Accounts
DREV0104	Revenue from Shoulder period Energy Delivery Charges	$0's	PEACE/Regulatory Accounts
DREV0105	Revenue from Off–Peak Energy Delivery charges	$0's	PEACE/Regulatory Accounts
DREV0106	Revenue from controlled load customer charges	$0's	PEACE/Regulatory Accounts
DREV0107	Revenue from unmetered supplies	$0's	PEACE/Regulatory Accounts
DREV0108	Revenue from Contracted Maximum Demand charges	$0's	PEACE/Regulatory Accounts
DREV0109	Revenue from Measured Maximum Demand charges	$0's	PEACE/Regulatory Accounts
DREV0110	Revenue from metering charges	$0's	PEACE/Regulatory Accounts
DREV0111	Revenue from connection charges	$0's	PEACE/Regulatory

Variable Code	Variable	Unit	Source
			Accounts
DREV0112	Revenue from public lighting charges	$0's	PEACE/Regulatory Accounts
DREV0113	Revenue from other Sources	$0's	PEACE/Regulatory Accounts
DREV01	Total revenue by chargeable quantity	$0's	PEACE/Regulatory Accounts

Table 3.1.3: Data Sources - RIN Table 3.1.2: Revenue Grouping by Customer Type or Class

Variable Code	Variable	Unit	Source
DREV0201	Revenue from residential Customers	$0's	PEACE/Regulatory Accounts
DREV0202	Revenue from non-residential customers not on demand tariffs	$0's	PEACE/Regulatory Accounts
DREV0203	Revenue from non-residential low voltage demand tariff customers	$0's	PEACE/Regulatory Accounts
DREV0204	Revenue from non-residential high voltage demand tariff customers	$0's	PEACE/Regulatory Accounts
DREV0205	Revenue from unmetered supplies	$0's	PEACE/Regulatory Accounts
DREV0206	Revenue from Other Customers	$0's	PEACE/Regulatory Accounts
DREV02	Total revenue by customer class	$0's	PEACE/Regulatory Accounts

Table 3.1.4: Data Sources – RIN Table 3.1.3: Revenue (penalties) allowed (deducted) through incentive schemes

Variable Code	Variable	Unit	Source
DREV0301	EBSS	$0's	Not applicable
DREV0302	STPIS	$0's	2014/15 Pricing Proposal

Variable Code	Variable	Unit	Source
DREV0303	F-Factor		Not applicable
DREV0304	S-Factor True up		Not applicable
DREV0305	Other		Not applicable
DREV03	Total revenue of incentive schemes	$0's	

3.1.1.3 Methodology

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. This database was used along with groupings of revenue classifications to report the revenue figures.

3.1.1.3.1 Assumptions

The following assumptions were applied:

- All network tariff codes (NTCs) are assumed to be 100% attributable to each applicable line item;
- It has been assumed that all controlled load NTCs can be grouped into "Residential Customers" (DREV0201). This has been assumed because 99.4% of all instances of the controlled load NTCs also are accompanied by the residential NTC; and
- All Feed in Tariff (FIT) payments for Solar NTCs has been excluded from the revenue Regulatory Template and have been included in the Opex Regulatory Template.
- STPIS as per the 2014/15 Pricing Proposal has been fully recovered in revenues collected

3.1.1.3.2 Approach

1) The following reports have been used for the 2014/15 regulatory year:
    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.

   The classifications of both tariff "category" and network tariff code are used to drive the classification of revenue into prescribed categories. The tariff category informs "RIN Table 3.1.1 – Revenue by chargeable quantity"; and the network tariff code informs "RIN Table 3.1.2 – Revenue by customer type".

3) For RIN Table 3.1.1 tariff "Categories" were contained in the source data from PEACE and these categories were used to classify most revenue transactions into chargeable quantities. Network tariff codes were used to calculate controlled load customer charges and customer types were used to classify unmetered revenue and public lighting. The mapping of these categories can be seen Table 3.1.5 below:

Table 3.1.5 – Categorisations used to classify revenue transactions

Variable Code	Variable Description	PEACE Tariff Category
DREV0101	Revenue from Fixed Customer Charges	FIXED
DREV0102	Revenue from Energy Delivery charges where time of use is not a determinant	VOLUME
DREV0103	Revenue from On–Peak Energy Delivery charges	VOLUME peak
DREV0104	Revenue from Shoulder period Energy Delivery Charges	VOLUME shoulder
DREV0105	Revenue from Off–Peak Energy Delivery charges	VOLUME off peak
DREV0106	Revenue from controlled load customer charges	NTC 9000 - Controlled Load 1 (super economy) NTC 9100 - Controlled Load 2 (economy)
DREV0107	Revenue from unmetered supplies	UMS & WML (Customer Type)
DREV0108	Revenue from Contracted Maximum Demand charges	CAPACITY
DREV0109	Revenue from Measured Maximum Demand charges	DEMAND
DREV0110	Revenue from metering charges	-
DREV0111	Revenue from connection charges	-
DREV0112	Revenue from public lighting charges	Streetlights (Customer Type)
DREV0113	Revenue from other Sources	-
DREV01	Total revenue by chargeable quantity	Calculated as sum of variables above

Due to the application of three different database classifications for grouping revenue transactions the risk of double counting needed to be managed. To ensure accuracy, where customer type or NTC was used the values were excluded from the revenue being reported by tariff category. The total values were then cross checked against the Regulatory Accounts.

4) The customer classification was mapped to the revenue data via the network tariff code. The classification of network tariff codes to the customer types can be seen in Table 3.1.6 below:

Table 3.1.6 – Classification of network tariff codes to the customer types

Variable Code	Variable	Network Tariff Code
DREV0201	Revenue from residential Customers	7600 - Residential - PeakSmart 8400 - Residential Flat 8900 - Residential TOU 9000 - Controlled Load 1 (super economy) 9100 - Controlled Load 2 (economy)
DREV0202	Revenue from non-residential customers not on demand tariffs	8500 - Business Flat 8800 - Business - TOU
DREV0203	Revenue from non-residential low voltage demand tariff customers	8100 - Demand Large 8200 - Demand Medium (121-400) 8300 - Demand Small
DREV0204	Revenue from non-residential high voltage demand tariff customers	1000 - (> 40 GWh pa) SSC 2000 - (>4 GWh pa) SSC - 110kV EG 2500 - (>4 GWh pa) SSC - 33kV EG 3000 - (>4 GWh pa) SSC - 11kV EG 3500 - (>4 GWh pa) SSC - 33kV Bus 4000 - (>4 GWh pa) SSC - 11kV Bus 4500 - (>4 GWh pa) SSC - 11kV Line 8000 - HV Demand
DREV0205	Revenue from unmetered supplies	9400 - Streetlights - Rate 3 9500 - Watchman Lights 9600 - Unmetered Supply
DREV0206	Revenue from Other Customers	-

Variable Code	Variable	Network Tariff Code
DREV02	Total revenue by customer class	Calculated as sum of variables above

5) Once all data was categorised, the figures were compared to the Regulatory Account totals. The key variances seen in the data were individually addressed:
   a. For the 2014/15 regulatory year, all unmetered supplies (being public lighting, watchman lights and other unmetered supplies) were billed in a similar manner. An additional Peace report was requested which breaks down the unmetered supplies into these three areas. This allowed Unmetered Supplies (DREV0107) and Revenue from Public Lighting (DREV0112) to have the correct allocation of unmetered supplies. This does not affect RIN Table 3.1.2 as both line items from RIN Table 3.1.1 are already aggregated into Revenue from Unmetered Supplies (DREV0205).

3.1.1.4 Estimated Information

No Estimated Information was reported

3.1.1.4.1 Justification for Estimated Information

Not applicable.

3.1.1.4.2 Basis for Estimated Information

Not applicable.

3.1.1.5 Explanatory Notes

Not applicable.

3.1.1.6 Accounting Policies

There were no accounting policy changes that would affect the reported revenue figures. However it should be noted that all revenue figures are based on actual figures reported in the Regulatory Accounts and not the statutory accounts. This will therefore not include any effects of over/under recovery accounts.

3.1.1 Revenue - Alternative Control Services

The AER requires Energex to provide the following information relating to Alternative Control Service (ACS) revenue:

3.1.1. Revenue grouping by chargeable quantity

- DREV0101 – Revenue from Fixed Customer Charges
- DREV0102 – Revenue from Energy Delivery charges where time of use is not a determinant
- DREV0103 – Revenue from On–Peak Energy Delivery charges
- DREV0104 – Revenue from Shoulder period Energy Delivery Charges
- DREV0105 – Revenue from Off–Peak Energy Delivery charges
- DREV0106 – Revenue from controlled load customer charges
- DREV0107 – Revenue from unmetered supplies
- DREV0108 – Revenue from Contracted Maximum Demand charges
- DREV0109 – Revenue from Measured Maximum Demand charges
- DREV0110 – Revenue from metering charges
- DREV0111 – Revenue from connection charges
- DREV0112 – Revenue from public lighting charges
- DREV0113 – Revenue from other Sources
- DREV01 – Total revenue by chargeable quantity

3.1.2 Revenue grouping by Customer type or class

- DREV0201 – Revenue from residential Customers
- DREV0202 – Revenue from non-residential customers not on demand tariffs
- DREV0203 – Revenue from non-residential low voltage demand tariff customers
- DREV0204 – Revenue from non-residential high voltage demand tariff customers
- DREV0205 – Revenue from unmetered supplies
- DREV0206 – Revenue from Other Customers
- DREV02 – Total revenue by customer class

3.1.3 Revenue (penalties) allowed (deducted) through incentive schemes

- DREV0301 – EBSS
- DREV0302 – STPIS
- DREV0303 – F-FActor
- DREV0304 – S-Factor True up
- DREV0305 – Other
- DREV03 - Total revenue of incentive schemes

These figures are a part of Regulatory Template 3.1 – Revenue.

All information reported for 2014/15 is Actual Information.

3.1.1.7 Consistency with EB RIN Requirements

Table 3.1.7 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.1.7 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report revenues by chargeable quantity (RIN Table 3.1.1) and by customer class (RIN Table 3.1.2).	Where figures exist the ACS revenue figures have been reported in line with the AERs requirements
The total of revenues by chargeable quantity must equal the total of revenues by customer class because they are simply two different ways of disaggregating revenue information.	Demonstrated in section 3.1.1.9.2 (Approach).
Energex must separately provide revenues received or deducted as a result of incentive schemes (RIN Table 3.1.3).	Not applicable to ACS
Total revenues for Direct Control Services will equal those reported in the Regulatory Accounting Statements (with the exception of total revenue in RIN Table 3.1.3).	Figures for ACS revenue have been generated from the Regulatory Accounts for 2015.
Revenues reported must be allocated to the chargeable quantity that most closely reflects the basis upon which the revenue was charged by Energex to customers… …Revenues that cannot be allocated to the specific chargeable quantities in variables DREV0101 to DREV0112 must be reported against ‘Revenue from other Sources’ (DREV0113).	Where possible, Energex has stated ACS revenues in line with those categories which most closely reflect how customers were charged. All other revenue was stated in “Revenue from Other Sources”
Energex must allocate revenues to the customer type that most closely reflects the customers from which Energex received its revenue. Revenues that Energex cannot allocate to the customer types DREV0201–DREV0205 must be reported against ‘Revenue from other Customers’ (DREV0206).	Where possible, Energex has stated ACS revenues in line with the AERs customer categories. All other revenue was stated in “Revenue from Other Customers”
ACS are defined in the NER. By way of context, ACS are intended to capture distribution services provided at the request of, or for the benefit of, specific customers with regulatory oversight of prices. Where an AER determination was not in effect at the time ACS are for DNSPs located in Queensland, excluded distribution services as determined by the Queensland Competition Authority	ACS has been reported for the year 2015.

3.1.1.8 Sources

Table 3.1.8, Table 3.1.9 and Table 3.1.10 demonstrate the sources from which Energex obtained the required information:

Table 3.1.8: Data Sources – RIN Table 3.1.1: Revenue grouping by chargeable quantity

Variable Code	Variable	Unit	Source
DREV0101	Revenue from Fixed Customer Charges	$0's	Regulatory Accounts/ PEACE reports / income statements
DREV0102	Revenue from Energy Delivery charges where time of use is not a determinant	$0's	Regulatory Accounts
DREV0103	Revenue from On–Peak Energy Delivery charges	$0's	Regulatory Accounts
DREV0104	Revenue from Shoulder period Energy Delivery Charges	$0's	Regulatory Accounts
DREV0105	Revenue from Off–Peak Energy Delivery charges	$0's	Regulatory Accounts
DREV0106	Revenue from controlled load customer charges	$0's	Regulatory Accounts
DREV0107	Revenue from unmetered supplies	$0's	Regulatory Accounts
DREV0108	Revenue from Contracted Maximum Demand charges	$0's	Regulatory Accounts
DREV0109	Revenue from Measured Maximum Demand charges	$0's	Regulatory Accounts
DREV0110	Revenue from metering charges	$0's	Regulatory Accounts / PEACE reports/ Income Statements
DREV0111	Revenue from connection charges	$0's	Regulatory Accounts
DREV0112	Revenue from public lighting charges	$0's	Regulatory Accounts/ Income Statements
DREV0113	Revenue from other Sources	$0's	Regulatory Accounts/ Income Statements
DREV01	Total revenue by chargeable quantity	$0's	Regulatory Accounts

Table 3.1.9: Data Sources – RIN Table 3.1.2: Revenue grouping by customer type or class

Variable Code	Variable	Unit	Source
DREV0201	Revenue from residential Customers	$0's	Regulatory Accounts
DREV0202	Revenue from non-residential customers not on demand tariffs	$0's	Regulatory Accounts
DREV0203	Revenue from non-residential low voltage demand tariff customers	$0's	Regulatory Accounts
DREV0204	Revenue from non-residential high voltage demand tariff customers	$0's	Regulatory Accounts
DREV0205	Revenue from unmetered supplies	$0's	Regulatory Accounts/ Income Statements
DREV0206	Revenue from Other Customers	$0's	Regulatory Accounts / PEACE reports/ Income Statements
DREV02	Total revenue by customer class	$0's	Regulatory Accounts

Table 3.1.10: Data Sources – RIN Table 3.1.3: Revenue (penalties) allowed (deducted) through incentive schemes

Variable Code	Variable	Unit	Source
DREV0301	EBSS	$0's	Not Applicable
DREV0302	STPIS	$0's	Not Applicable
DREV0303	S-Factor	$0's	Not Applicable
DREV0304	S-Factor True up	$0's	Not Applicable
DREV0305	Other	$0's	Not Applicable
DREV03	Total revenue of incentive schemes	$0's	Not Applicable

3.1.1.9 Methodology

Figures for ACS revenue have been generated from the Regulatory Accounts for 2015.

3.1.1.9.1 Assumptions

No assumptions were applied.

3.1.1.9.2 Approach

All figures are based on the Regulatory Accounts submitted to the AER. Data was obtained from the annual RIN submitted. The reported ACS revenue figures and their method of calculation from the source documentation is provided in the Table 3.1.11:

Table 3.1.11 – ACS Revenue figures and methodology

Variable Code	Variable Description	Construction Methodology
DREV0101	Revenue from Fixed Customer Charges	Calculated as the sum of revenue figures stated for fee based ACS minus the revenue stated for DREV0110 – Revenue from metering charges
DREV0110	Revenue from metering charges	The figures were calculated as the sum of revenue figures stated for fee based ACS relating to metering. This includes: • Meter test • Meter inspection • Reconfigure meter • Off-cycle meter read • Special Meter Reads • Meter Investigation • It also included all Fee Based capital contributions revenue as these are related to metering charges.
DREV0112	Revenue from public lighting charges	The figure is inclusive of street lighting fixed charges. It also included all Street Lighting capital contributions revenue.
DREV0113	Revenue from other Sources	Calculated as the total for Quoted Services Revenue. It also included Quoted Services capital contributions.
DREV01	Total revenue by chargeable quantity	Calculated as the sum of variables DREV0101, DREV0110, DREV0112 and DREV0113.
DREV0205	Revenue from unmetered supplies	Calculated as the value for street lighting revenue stated in DREV0112.
DREV0206	Revenue from Other Customers	Calculated as the total revenue stated in DREV01 minus that stated for street lighting in DREV0112
DREV02	Total revenue by customer class	Calculated as the total revenue stated in DREV01.

Revenue (penalties) allowed (deducted) through incentive schemes

- Incentive schemes do not apply to ACS and therefore no revenue or penalties have been reported.

3.1.1.10 Estimated Information

No Estimated Information was reported.

3.1.1.10.1 Justification for Estimated Information

Not applicable.

3.1.1.10.2 Basis for Estimated Information

Not applicable.

3.1.1.11 Explanatory Notes

Not applicable.

3.1.1.12 Accounting Policies

There were no accounting policy changes that would affect the reported revenue figures.

3.2 OPEX

3.2.1 Operating Expenditure

The AER requires Energex to provide the following information relating to Opex for Standard Control Services (SCS) and Alternative Control Services (ACS):

Table 3.2.1 Opex Categories

Table 3.2.1.1 Current opex categories and cost allocations

- **DOPEX0101-13 – Individual opex categories per annual Regulatory Accounting Statements**
- **DOPEX01 – Total opex**
- **Table 3.2.1.2A Historical opex categories and cost allocations**
- **DOPEX0101-13A – Individual opex categories per annual Regulatory Accounting Statements**
- **DOPEX01A – Total opex**

Table 3.2.2 Opex consistency

Table 3.2.2.1 Opex consistency – current cost allocation approach

- **DOPEX0201 – Opex for network services (required for SCS only)**
- **DOPEX0202 – Opex for metering**
- **DOPEX0203 – Opex for connection services**
- **DOPEX0204 – Opex for public lighting**
- **DOPEX0205 – Opex for amounts payable for easement levy or similar direct charges on DNSP**
- **DOPEX0206 – Opex for transmission connection point planning**

Table 3.2.2.2 Opex consistency – historical current cost allocation approach

- **DOPEX0201A – Opex for network services (required for SCS only)**
- **DOPEX0202A – Opex for metering**
- **DOPEX0203A – Opex for connection services**
- **DOPEX0204A – Opex for public lighting**
- **DOPEX0205A – Opex for amounts payable for easement levy or similar direct charges on DNSP**
- **DOPEX0206A – Opex for transmission connection point planning**

All information is Actual Information.

3.2.1.1 Consistency with EB RIN Requirements

Table 3.2.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.2.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report Opex in accordance with the categories that they reported in response to their Annual Reporting Requirements.	RIN tables 3.1.1 and 3.1.2 are now tables 3.2.1.1 and 3.2.1.2 Energex has reported Opex in accordance with the categories reported in response to the 2014/15 Annual Reporting Requirements as detailed in RIN tables 3.2.1.1 and 3.2.1.2A.
Energex is required to complete the "Current Opex categories and cost allocations" table if there has been a Material change (over the course of the back cast time series) in Energex's Cost Allocation Approach, basis of preparation for its Regulatory Accounting Statements or Annual Reporting Requirements.	As this basis of preparation is for the 2014/15 regulatory year (i.e. one year only), Opex in RIN table 3.2.1.1 "Current Opex categories and cost allocations" is the same as Opex in RIN table 3.2.1.2A "Historical Opex categories and cost allocations". Energex has reported Opex in accordance with the categories reported in response to the Annual Reporting Requirements.
Opex in table 3.1.1 must be prepared for all Regulatory Years in accordance with Energex's Cost Allocation Approach and directions within the Annual Reporting Requirements for the most recent completed Regulatory Year. For years where the Cost Allocation Approach and Regulatory Accounting Statements are consistent with those that applied in the most recent completed Regulatory year, total Opex should equal that reported in the Regulatory Accounting Statements.	RIN table 3.1.1 is now RIN table 3.2.1.1 The Opex amounts in RIN table 3.2.1.1 have been prepared in accordance with Energex's Cost Allocation Approach and directions within the Annual Reporting Requirements for 2014/15. Total Opex equals that reported in the 2014/15 Regulatory Accounting Statements.
Energex must report its historical Opex categories in table 3.1.2 in accordance with the Opex activities (eg. vegetation management, emergency response Opex, etc.) within the Annual Reporting Requirements that applied in the relevant Regulatory Year. These categories must align with the activities reported in response to the Annual Reporting Requirements for each Regulatory Year. Opex line items reported in table 3.1.2 should equal Opex line items reported in the Regulatory Accounting Statements for each Regulatory Year.	RIN table 3.1.2 is now RIN table 3.2.1.2 Energex has reported its historical Opex categories in accordance with the Opex within the Annual Reporting Requirements that applied in 2014/15. The Opex amounts reported in RIN table 3.2.1.2A equal Opex line items reported in the 2014/15 Regulatory Accounting Statements.
For table 3.2.1 Energex must report Opex for the Opex Variables in accordance with its current reporting arrangements (such as its Cost Allocation Approach). This table must be completed if there has been a Material change (over the course of the back cast time series) in	RIN table 3.2.1 is now RIN table 3.2.2.1 Energex has reported Opex in the categories as defined in the AER EB RIN in accordance with its current Cost Allocation Approach. Total Opex for SCS in this table aligns with that

Requirements (instructions and definitions)	Consistency with requirements
Energex's Cost Allocation Approach, basis of preparation for its Regulatory Accounting Statements or Annual Reporting Requirements.	in the 2014/15 Regulatory Accounting Statements.
For table 3.2.2 Energex must report Opex in accordance with the AER Variables and the Cost Allocation Approaches and reporting framework applied in the relevant Regulatory Years.	RIN table 3.2.2 is now RIN table 3.2.2.2 Energex has reported Opex in the categories as defined in the AER EB RIN in accordance with its current Cost Allocation Approach. Total Opex for SCS in this table aligns with that in the 2014/15 Regulatory Accounting Statements.

3.2.1.2 Sources

Table 3.2.2 and Table 3.2.3 and Table 3.2.4 below demonstrate the sources from which Energex obtained the required information:

Table 3.2.2: Data Sources – RIN Table 3.2.1.1 Current opex categories and cost allocations

Variable Code	Variable	Unit	Source
DOPEX0101-13	Individual opex categories	$0's	Annual Regulatory Accounting Statements
DOPEX01	Total opex	$0's	Annual Regulatory Accounting Statements
3.2.1.2A Historical opex categories and cost allocations			
DOPEX0101-13A	Individual opex categories	$0's	Annual Regulatory Accounting Statements
DOPEX01A	Total opex	$0's	Annual Regulatory Accounting Statements

Table 3.2.3: Data Sources – RIN table 3.2.2.1: Opex consistency - current cost allocation approach

Variable Code	Variable	Unit	Source
DOPEX0201	Opex for network services	$0's	Annual Regulatory Accounting Statements, Ellipse Project Ledger
DOPEX0202	Opex for metering	$0's	Annual Regulatory Accounting Statements, Ellipse Project Ledger
DOPEX0203	Opex for connection services	$0's	Not applicable
DOPEX0204	Opex for public lighting	$0's	Annual Regulatory

Variable Code	Variable	Unit	Source
			Accounting Statements
DOPEX0205	Opex for amounts payable for easement levy or similar direct charges on DNSP	$0’s	Not applicable
DOPEX0206	Opex for transmission connection point planning	$0’s	Not applicable

Table 3.2.4: Data Sources – RIN table 3.2.2.2: Opex consistency - historical cost allocation approach

Variable Code	Variable	Unit	Source
DOPEX0201A	Opex for network services	$0’s	Annual Regulatory Accounting Statements, Ellipse Project Ledger
DOPEX0202A	Opex for metering	$0’s	Annual Regulatory Accounting Statements, Ellipse Project Ledger
DOPEX0203A	Opex for connection services	$0’s	Not applicable
DOPEX0204A	Opex for public lighting	$0’s	Annual Regulatory Accounting Statements
DOPEX0205A	Opex for amounts payable for easement levy or similar direct charges on DNSP	$0’s	Not applicable
DOPEX0206A	Opex for transmission connection point planning	$0’s	Not applicable

3.2.1.3 Methodology

Separate methodologies were applied for each table within the Opex worksheet. The methodologies stated in this basis of preparation relate to both SCS and ACS.

3.2.1.3.1 Assumptions

No assumptions were made.

3.2.1.3.2 Approach

RIN Table 3.2.1.1 Current opex categories and cost allocations and RIN Table 3.2.1.2 Historical opex categories and cost allocations:

- RIN Table 3.2.1.1 requires Opex be stated on the basis of the current Cost Allocation Approach. RIN Table 3.2.1.2 requires Opex be stated on the basis of the Cost Allocation Method (CAM) used in the applicable regulatory year.
- As the current CoS (Classification of Services) and CAM have been applied from the 2011 regulatory year, the amounts stated for 2014/15 for both RIN Tables 3.2.1.1 and 3.2.1.2 are the same and have been taken directly from the 2014/15 Regulatory Accounting Statements.

Opex consistency – current cost allocation approach

- The Opex consistency table based on the current CAM (table 3.2.2.1) has been based on the values stated in RIN Table 3.2.1.1 Current opex categories and cost allocations.
- RIN Table 3.2.1.1 balances to RIN Table 3.2.2.1 for SCS only. ACS will not balance between the two tables as RIN Table 3.2.2.1 does not require the ACS Opex categories reported against DOPEX0113 from RIN Table 3.2.1.1.

DOPEX0201 – Opex for network services

- Network services are defined in the EB RIN Instructions and Definitions as “a subset of Standard Control Services that excludes Connection Services, Metering services, Fee Based and Quoted Services and Public Lighting Services”. Based on this definition the value for “DOPEX0201 – Opex for network services” has been calculated as the total Opex value stated in RIN Table 3.2.1.1 minus the values for:
  - DOPEX0202 – Opex for metering
  - DOPEX0203 – Opex for connection services
  - DOPEX0204 – Opex for public lighting

DOPEX0202 – Opex for metering

- The variable “DOPEX0202 – Opex for metering” could not be calculated directly from amounts in RIN Table 3.2.1.1 for the following two reasons:
  - The variable for “Meter reading and network billing” included network billing expenditure which was required to be removed in accordance with the definition of Metering.
  - There was expenditure within other variables that related to operating and maintenance (O&M) costs for Metering which needed to be included in the Opex for Metering amount. The formula used for calculating Opex for Metering was therefore:

$$Opex\ for\ Metering = Metering\ Dynamics + Meter\ Reading\ and\ Network\ Billing - Network\ Billing\ Costs + O\&M\ Costs\ of\ Metering$$

- The network billing component is identified by the specific responsibility centre coding for network billing activities.
- The metering O&M costs for 2014/15 were extracted from project ledger information in Ellipse.
- Once all amounts were obtained for network billing and metering O&M costs, Opex for Metering was calculated using the formula above.

DOPEX0203 – Opex for connection services

- The amount for “DOPEX0203 – Opex for connection services” is classified as Capex as per definition.

DOPEX0205 – Opex for amounts payable for easement levy or similar direct charges on DNSP

- The amount for “DOPEX0205 – Opex for amounts payable for easement levy or similar direct charges on DNSP” is zero as Energex does not pay any easement levies.

DOPEX0206 – Opex for transmission connection point planning

- Energex does not have any Opex attributable to “DOPEX0206 - Opex for transmission connection point planning” and therefore the amount for this variable is zero.

Opex consistency – historical cost allocation approaches

- As the current CoS and CAM have been applied from the 2011 regulatory year, amounts in RIN Table 3.2.2.2 are the same for those stated in RIN Table 3.2.2.1.

3.2.1.4 Estimated Information

No Estimated Information was reported.

3.2.1.4.1 Justification for Estimated Information

Not applicable.

3.2.1.4.2 Basis for Estimated Information

Not applicable.

3.2.1.5 Explanatory Notes

Current opex categories and cost allocations

The following explanations are provided in relation to RIN Table 3.2.1.1 Current opex categories and cost allocations:

- Other network maintenance costs (DOPEX0106) represent maintenance costs for street lights.
- SCS Other operating costs (DOPEX0113) includes solar photovoltaic (PV) feed in tariff (FiT) payments. For transparency, solar PV FiT payments for 2014/15 were $203.8M.

The following explanations are provided for the major variances between 2014/15 and 2013/14:

- DOPEX0104 Vegetation costs have continued to reduce ($13.5M, 17%) mainly due to Energex having negotiated a monthly fee with the contractors in December 2013 for vegetation management rather than the previous method of payment based on kilometres. This has delivered savings for the business.
- DOPEX0105 Emergency response/storms costs have increased ($4M, 70%) due to six major storm events in 2014/15 including the November 2014 super cell storm compared to only three events in 2013/14.
- DOPEX0109 Customer services (incl. call centres) costs have decreased ($3.3M, 14%) due to the completion of the overhead service line inspection program in 2013/14. This work was originally provided for as part of the overhead service line provision (with the corresponding increase to DOPEX0101 Inspection in 2012), however when the work is performed it is incurred as a Customer Service expense.
- DOPEX0110 DSM (Demand Side Management) initiatives costs have increased ($5.7M, 33%) due to the increase in the Demand Management programs with eligible incentives payments paid. For example, this year we have paid for a much larger number of PeakSmart units in our PeakSmart program with the number of incentives paid for air conditioning units increasing 96%.

3.2.1.6 Accounting Policies

Energex changed its accounting policy in 2014/15 with respect to regulated revenue under and over recoveries. Previously, Energex accrued or deferred allowed regulated revenues through recognising the full amount of revenue allowed under its revenue determination and recognising any under (or over) recovery of this amount as an asset (or liability) to be adjusted in future revenues to be received from customers.

3.2.1.6.1 Nature of Change

There is no definitive guidance on the accounting treatment for regulatory receivables or provisions within existing accounting standards. However the Australian Accounting Standards Board (AASB) has commented, in response to the International Accounting Standards Board's (IASB) *Invitation to Comment ITC32 Reporting the Financial Effects of Rate Regulation*; that it has a view that, in most cases, regulatory deferral account balances do not meet the asset and liability recognition criteria as contained in the AASB's *Conceptual Framework*. To date, consensus has not been achieved and divergent views continue to be debated by the IASB.

The new policy, where the accrued (or deferred) revenues are not recognised, results in more reliable and relevant information to users as it reflects a closer correlation between market conditions, shareholder and other regulatory policies and profitability.

3.2.1.6.2 Impact of Change

As regulated revenue under (or over) recoveries are no longer recognised in the Statutory Accounts the treatment is in line with the Regulatory reporting.

There is no impact on Opex reported.

3.2.4 Opex for HV Customers

The AER requires Energex to provide the following information relating to opex for High Voltage Customers:

3.2.4 Opex for High Voltage Customers (required for SCS only)

- **DOPEX0401 – Opex for High Voltage Customers**

This variable is a part of worksheet 3.2 – Opex.

All information is Estimated Information.

3.2.4.1 Consistency with EB RIN Requirements

Table 3.2.5 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.2.5 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the amount of Opex that it would have incurred had it been responsible for operating and maintaining the electricity Distribution Transformers that are owned by its high voltage customers. Where Actual Information is unavailable, this must be estimated based on the Opex Energex incurred for operating similar MVA capacity Distribution Transformers within its own network. Where the MVA capacity of high voltage customer-owned Distribution Transformers is not known, it must be approximated by the observed Maximum Demand for that customer.	Energex is not required, and as a result does not, keep any records relating to electricity distribution transformers which are owned by its high voltage customers. As such, for reporting purposes, Energex has estimated the Opex which would otherwise have been expensed, had the company been responsible for their maintenance. The estimate of this avoided cost is derived by applying a theoretical ratio of operating expenditure to transformer capacity for Energex owned transformers used by LV metered, site specific customers, to the assumed capacities of customer owned transformers. The ratio is calculated using known capacity data and by allocating a nominal portion of total Opex required for maintenance, based on the replacement cost of the transformers as a total of the overall asset base. Only LV metered site specific customers were considered due to relevance and the completeness of the data set available (not many HV metered customers are Energex owned).

3.2.4.2 Sources

Table 3.2.6 below demonstrate the sources from which Energex obtained the required information.

Table 3.2.6: Data Sources

RIN Table 3.2.4 Opex for high voltage customers for 2014/15			
Variable Code	**Variable**	**Unit**	**Source**
DOPEX0401	Opex for high voltage customers	$0's	Peace report and Pricing model

3.2.4.3 Methodology

Opex in RIN table 3.2.4 was estimated using data for known Energex high voltage customers.

3.2.4.3.1 Assumptions

No assumptions were applied.

3.2.4.3.2 Approach

Energex is required to report the Opex it would have incurred if it managed the high voltage (HV) transformers that are managed by customers. This information is not measured and it is therefore estimated by multiplying an assumed ratio of maintenance costs per MVA of transformer capacity, derived from actual data for LV metered, site specific customers using Energex managed distribution transformers.

The approach involves two steps; estimating customer owned transformer capacity based on known demand data, and deriving the aforementioned ratio. The following points detail the methodology used for the 2014/15 report:

1) NMIs with the following network tariff codes (NTCs) were determined as high voltage demand customers:
    a. 1000 – (> 40 GWh pa) SSC
    b. 2000 – (>4 GWh pa) SSC - 110kV EG
    c. 2500 – (>4 GWh pa) SSC - 33kV EG
    d. 3000 – (>4 GWh pa) SSC - 11kV EG
    e. 3500 – (>4 GWh pa) SSC - 33kV Bus
    f. 4000 – (>4 GWh pa) SSC - 11kV Bus
    g. 4500 – (>4 GWh pa) SSC - 11kV Line
    h. 8000 – HV Demand

Data was obtained from the Energex Meter Data Agency team that contains the monthly maximum demand figures for high voltage demand customers.

2) The data set of NMIs from the Meter Data Agency reports was cross-checked against a list of HV Metered customers obtained from Network Pricing. Only those NMIs that had a HV NTC and were known to be a HV metered customer were included (as some HV demand customers have low voltage meters).

3) The transformer capacity for each NMI was estimated for each year as a function of the maximum demand. To do this the transformer capacities and average maximum demand figures for 2014/15 were extracted for HV NMIs where Energex manages the distribution transformer. Using these figures an average utilisation rate of the maximum transformer capacity was calculated at 48.1%. Maximum demand figures extracted in steps 1 and 2 were then divided by 0.481 to obtain estimated customer owned transformer capacities.

4) The operating unit cost per MVA of capacity, required to maintain Energex-managed distribution transformers was estimated using the following formula:

$$\$/MVA = \frac{Total\ operating\ cost \times \frac{Replacement\ cost\ of\ Energex\ LV\ metered\ site\ specific\ customer\ transformers}{Replacement\ cost\ of\ total\ Energex\ assets}}{Total\ capacity\ of\ Energex\ LV\ metered\ site\ specific\ customer\ transformers}$$

5) The unit operating cost per MVA of capacity calculated in step 4 was multiplied by the total estimated customer transformer capacity calculated in step 3 to produce a hypothetical Opex for customer owned distribution transformers that would have been expensed in each regulatory year.

3.2.4.4 Estimated Information

All figures provided in RIN table 3.2.4 for high voltage customers are Estimated Information.

3.2.4.4.1 Justification for Estimated Information

The opex for High voltage customers where Energex does not own the distribution transformer is not measured by Energex and is inherently estimated.

3.2.4.4.2 Basis for Estimated Information

All information has been calculated by multiplying an estimate of HV customer owned transformer capacity by the operating unit cost per MVA of capacity observed in Energex-managed distribution transformers.

3.2.4.5 Explanatory Notes

Estimated Opex for HV Customers increased from an estimated $1.912M in 2013/14 to an estimated $2.820M in 2014/15. This increase is predominantly attributable to a higher 'Replacement Cost of Energex LV metered site specific customer transformers' relative to the 'Replacement cost of total Energex assets'. This change in relativity has come about due to proportionally larger increases in the estimates underpinning the replacement cost of transformers, particularly those in the underground network which represents the majority of large customer connections included in this calculation. These estimates increased due to improved accuracy based on analysis of actual jobs that showed additional hours, particularly in job planning and design, a more thorough materials listing, and updated to reflect the actual overhead cost allocation methodology is use.

3.2.4.6 Accounting Policies

There has been no accounting policy change that impacts on this variable.

3.2.3 PROVISIONS

3.2.3 Provisions

The AER requires Energex to provide the following information relating to provisions for Standard Control Services (SCS):

Table 3.2.3 Provisions

- **DOPEX0301-14A Provision for Dividends**
- **DOPEX0301-14B Provision for Site Restoration – Toowoomba**
- **DOPEX0301-14C Provision for Site Restoration - Other**
- **DOPEX0301-14D Provision for Public Liability Insurance**
- **DOPEX0301-14E Provision for Employee Benefits**
- **DOPEX0301-14F Provision for Redundancy**
- **DOPEX0301-14G Provision for Circuit Breaker Replacements**
- **DOPEX0301-14H Provision for Environmental Offsets**
- **DOPEX0301-14I Provision for Other**

These variables are a part of worksheet 3.2.3 and are reported for regulatory year 2015.

All information is Actual Information.

3.2.3.1 Consistency with EB RIN Requirements

Table 3.2.6 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.2.6 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report, for all Regulatory Years, financial information on provisions for Standard Control Services in accordance with the requirements of the Cost Allocation Approach and the Regulatory Accounting Statements that were in effect for the relevant Regulatory Year. Provisions must be reported in accordance with the principles and policies within the Annual Reporting Requirements for each Regulatory Year. Financial information on provisions should reconcile to the reported amounts for provisions in the Regulatory Accounting Statements for each Regulatory Year.	Energex has reported financial information on provisions for Standard Control Services. 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 2015 provisions. Provisions are allocated to services based on Property, Plant & Equipment (PP&E) balances, consistent with the methodology applied in apportioning balance sheet items among services adopted in previous years' Regulatory Accounting Statements. Therefore the provision amount attributed to SCS is based on the proportion of the SCS PP&E to the total PP&E. Provisions that are charged to indirect expenditure are apportioned to Opex and Capex components for the EB RIN based on the overhead allocation ratio for 2015, sourced from the supporting workings for the 2015 Regulatory Accounting Statements.

3.2.3.2 Sources

Reporting for all provisions is based on the 2015 statutory financial statements and Regulatory Accounting Statements workings.

3.2.3.3 Methodology

Methodology for the provisions reporting is detailed below.

3.2.3.3.1 Assumptions

The difference in PP&E allocation percentages between the applicable regulatory year (2015) and prior (2014) regulatory year is treated as follows:

- adjustments that resulted in increased provisions are assumed to be additions to provisions; and
- adjustments that resulted in decreased provisions are assumed to be unused amounts reversed.

3.2.3.3.2 Approach

- Provisions are allocated to services based on PP&E balances, which is consistent with the annual Regulatory Accounting Statements up to 2013. Allocation of opening balances is based on the closing PP&E balances of the prior regulatory year. The 2015 regulatory year movements and the closing balances are allocated based on the closing PP&E balances of the 2015 regulatory year.
- 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. Therefore, provisions that are charged to indirect expenditure are apportioned to Opex and Capex components for the EB RIN based on the overhead allocation ratio for the relevant year, sourced from the supporting workings for the annual Regulatory Accounting Statements. This information is reported as Actual Information as the overhead allocation to Capex and Opex is based on the AER approved CAM (Cost Allocation Method) and sourced from the General Ledger and therefore considered to be Actual Information.
- Provision for Employee Benefits was allocated to Opex and Capex based on the overhead allocation ratio and therefore reported as Estimated Information in 2014. However, for 2015 the allocation to Opex and Capex is based on labour deployment balances sourced from the General Ledger and therefore is reported as Actual Information. Refer to Table 3.2.7 for more background information.
- Table 3.2.7 provides background on each of the provisions:

Table 3.2.7 – Capex and Opex apportionment for each of the Provisions (SCS)

Variable Code	Variable	Capex and Opex Components
DOPEX0301-14A	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 EB RIN under Other Component.
DOPEX0301-14B	Provision for Site Restoration - Toowoomba	Charged to Other as it represents unregulated expenditure for a former gas site.
DOPEX0301-14C	Provision for Site Restoration - Other	Charged to indirect expenditure and allocated to Opex and Capex through overhead allocations.
DOPEX0301-14D	Provision for Public Liability Insurance	Charged to indirect expenditure and allocated to Opex and Capex through overhead allocations.
DOPEX0301-14E	Provision for Employee Benefits	Charged to indirect expenditure and allocated to Opex and Capex through Energex labour costing processes. Energex uses a standard costing method to apply labour costs to activities. Labour costing entries are processed to standard indirect expense accounts. At the end of the month the wages paid/wages costed balances in the corporate Income statement are transferred to the Labour costing over/under recoveries balance sheet account. The balance of this account represents the total year-to-date variance between labour costed and wages paid. At the end of the financial year, the balance of the Labour Costing Over/Under Recoveries Account in the balance sheet is cleared and distributed across the divisions and spread over operating and capital costs based on labour deployment balances from the General Ledger. 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 EB 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 allocation rate based on labour deployment balance from the General Ledger. The amount for

Variable Code	Variable	Capex and Opex Components
		leave entitlements is the accrued leave balance per payroll records plus on-costs such as payroll tax, superannuation and workers' compensation.
DOPEX0301-14F	Provision for Redundancy	Charged to other support cost directly, therefore 100% allocated to Opex.
DOPEX0301-14G	Provision for Circuit Breaker Replacements	Charged to planned maintenance costs directly, therefore 100% allocated to Opex.
DOPEX0301-14H	Provision for Environmental Offsets	Charged to Opex and Capex directly based on relevant components, not through overhead allocations.
DOPEX0301-14I	Provision for Other	Charged to indirect expenditure and allocated to Opex and Capex through overhead allocations.

3.2.3.4 Estimated Information

No Estimated Information was reported.

3.2.3.4.1 Justification for Estimated Information

Not applicable.

3.2.3.4.2 Basis for Estimated Information

Not applicable.

3.2.3.5 Explanatory Notes

The following explanations are provided in relation to provisions:

- Provision for Dividends (DOPEX0301A – DOPEX0314A) – There has been a significant increase this year due to the100% of net profit after tax (NPAT) being distributed as dividends along with an additional distribution of $783M from retained earnings and reserves. The distribution from retained earnings and reserves and the increase in the dividend ratio form 80% to 100% of NPAT were made in response to a direction from the shareholding Ministers, dated 29 June 2015, under section 131(3)(b) of the *Government Owned Corporations Act 1993.*

- Provision for Site Restoration – Other (DOPEX0301C – DOPEX014C) – The significant increase this year is mainly due to an additional provision raised for the demolition and remedial work required at the Banyo site.

- Provision for Public liability Insurance (DOPEX0301D – DOPEX0314D) – The increase in provision this year is due to additional provision for payments being made for several multi-claim incidents in excess of the annual provision previously raised and two new claims relating to incidents prior to 2008/09 that have been identified during the year.

- Provision for Employee Benefits (DOPEX0301E – DOPEX0314E) – The decrease in provision is primarily driven by the change in the discount rate, from using the 10 year commonwealth bond rate (3.0% at 30 June 2015, 3.5% at 30 June 2014) to a high quality corporate bond rate (4.4%). Consequently, the net present value of employee leave liabilities has reduced. The value of employee benefits provision is also impacted by the ongoing reduction in staff numbers.

- Provision for Redundancy (DOPEX0301F – DOPEX0314F) – There has been a significant increase in this provision for committed retrenchment costs as Energex looks to reduce its workforce consistent with stakeholder's expectation.

- Provision for Circuit Breaker Replacements (DOPEX0301G – DOPEX0314G) – The provision is raised as a result of identification of faulty circuit breakers. Energex has an obligation to ensure these faulty items are replaced to maintain a safe and reliable electricity network.

3.3 ASSETS (RAB)

3.3.1 Asset (RAB) Values

As per the AER (Australian Energy Regulator) requirements, Energex is providing the following variables for Standard Control Services (SCS), Alternative Control Services (ACS) and Network Services (NS):

Table 3.3.1 Regulatory Asset Base Values

- **DRAB0101 – Opening value**
- **DRAB0102 – Inflation addition**
- **DRAB0103 – Straight line depreciation**
- **DRAB0105 – Actual additions (recognised in RAB)**
- **DRAB0106 – Disposals**

Table 3.3.2 Asset Value Roll Forward (the seven variables above broken down to specific asset categories)

- **DRAB0201 to 0207 – For overhead network assets less than 33 kV**
- **DRAB0301 to 0307 – For underground network assets less than 33 kV**
- **DRAB0401 to 0407 – For distribution substations and transformers**
- **DRAB0501 to 0507 – For overhead network assets 33 kV and above**
- **DRAB0601 to 0607 – For underground network assets 33 kV and above**
- **DRAB0701 to 0707 – Zone substations and transformers**
- **DRAB0801 to 0807 – For easements**
- **DRAB0901 to 0907 – For meters**
- **DRAB1001 to 1007 – For "other" asset items with long lives**
- **DRAB1101 to 1107 – For "other" asset items with short lives**

Table 3.3.3 Total Disaggregated RAB Asset Values

- **DRAB1201 – Overhead distribution assets less than 33 kV (wires and poles)**
- **DRAB1202 – Underground distribution assets less than 33 kV (cables, ducts etc.)**
- **DRAB1203 – Distribution substations including transformers**
- **DRAB1204 – Overhead assets 33 kV and above (wires and towers / poles etc.)**
- **DRAB1205 – Underground assets 33 kV and above (cables, ducts etc.)**
- **DRAB1206 – Zone substations**
- **DRAB1207 – Easements**
- **DRAB1208 – Meters**
- **DRAB1209 – Other assets with long lives (please specify)**
- **DRAB1210 – Other assets with short lives (please specify)**
- **DRAB13 – Value of Capital Contributions or Contributed Assets**

These variables are a part of worksheet 3.3 Assets (RAB) and have been calculated using the AER Regulated Asset Base (RAB) Roll Forward Model (RFM). The exception is DRAB13 – Value of Capital Contributions or Contributed Assets, which was obtained directly from the annual Regulatory Accounting Statements and/or supporting workings.

The following information is Estimated Information:

- **NS - Tables 3.3.2 Asset Value Roll Forward (the seven variables above broken down to specific asset categories) and 3.3.3 Total Disaggregated RAB Asset Values**
- **NS - Capital Contributions (DRAB13)**

3.3.1.1 Consistency with EB RIN Requirements

The AER requires Energex report its Regulated Asset Base (RAB) both in total figures and disaggregated into the asset categories defined in the Economic Benchmarking RIN templates. The definitions of these asset categories can be seen in section 3.3.1.5 Explanatory Notes, Table 3.3.7.

Table 3.3.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.3.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report RAB values in accordance with the standard approach in section 4.1.1 and the Assets (RAB) Financial Reporting Framework in Box 7 below. This is a standard approach that must be used for RAB disaggregation to be followed by all Distribution Network Service Providers (DNSPs) (the Standard Approach).	Energex has produced the RAB amounts for the EB RIN based on the RAB RFM from the AER's – Preliminary Decision Energex Determination 2015-16 to 2019-20 (Preliminary Decision). The opening balance RAB values for 2014/15 have been sourced from the Preliminary Decision. Consistent with the requirements of the EB RIN, 2014/15 values have been populated with actual information (e.g. capital expenditure, asset disposals) from the annual Regulatory Accounting Statements for 2014/15.
Where Energex believes it has sufficient information to provide a consistent RAB disaggregation into the RAB Assets in the Assets (RAB) worksheet that better reflects the values of those assets (the Optional Additional Approach), they may also provide this in a separate Excel worksheet.	The RAB RFM disaggregates Energex's regulated assets into 29 asset categories. Each of these categories was allocated to one of the 10 specified for the EB RIN, the mapping of which can be found in **Table 3.3.7**. This approach aligns to the standard approach defined by the AER above and as such the optional additional approach has not been used.
Where RAB Financial Information that can be Directly Allocated to the RAB Assets (as per the definitions in chapter 9) it must be Directly Allocated to those RAB Assets. Financial information can be Directly Allocated to a RAB Asset class where that financial information relates to assets that wholly fall within the definition of that RAB Asset class. For example, financial data associated with poles can be Directly Allocated to Overhead Distribution Assets (Wires And Poles)… …RAB Financial Information that cannot be Directly Allocated to a single asset category should be allocated in accordance with the RAB allocation	All categories were allocated to a single RAB Asset Class.

Requirements (instructions and definitions)	Consistency with requirements
approach.	
Alternate Control Services Energex must report the RAB values for its services where the AER has approved a RAB or RAB equivalent for these services. If the AER has not developed a RAB for these services Energex must report ‘0’ in the cells.	ACS has only existed in Energex from regulatory year 2011. From their inception the ACS in Energex have contained street lighting services, quoted and fee based services. As the AER only developed a RAB for street lighting services based on the limited building block approach, only street lighting services are included in the RFM, consistent with the EB RIN Instructions and Definitions. All other asset categories for ACS have been marked as zero as per the AER guidance.
Substation land must be included in the ‘substation asset’ category. Separate values for substation land may be provided in accompanying documentation to the RIN response. Where the RAB includes capital contributions, capital contributions must be reported in the ‘4. Assets (RAB)’ sheet. This data must be provided as a separate entry at DRAB13. RAB Assets must be reported inclusive of Dual Function Assets that provide Standard Control Services.	Substation land has been included in the substation asset category. For details please refer to section 3.3.1.5 Explanatory Notes, Table 3.3.7. The Energex RAB is inclusive of capital contributions. As such the capital contributions have been included in RIN table 3.3.3.

For the purposes of the EB RIN the SCS and ACS data has been treated as actual information for the following reasons:

- The AER has determined the closing RAB values for 2013/14 in the Preliminary Decision Energex Determination 2015-16 to 2019-20 (Preliminary Decision); and
- 2014/15 values are calculated based on actual information from the Regulatory Accounting Statements; and therefore,
- ‘it is not contingent on judgements and/or assumptions for which there are valid alternatives, which could lead to a materially different presentation’. (This reflected the definition of ‘Actual Information’ as provided in the AER’s Instructions and Definitions.)

3.3.1.2 Sources

The closing balance of the RAB for 2013/14 (opening balance 2014/15) has been sourced from the RFM from the AER's Preliminary Decision. For 2014/15, the inputs to the RFM have been sourced as follows:

- Actual capex and disposals – Sourced from the Annual Regulatory Accounts;
- CPI information – Sourced from the Australian Bureau of Statistics (ABS) data series A2325846C (eight capital cities from March to March), in line with the AER approach; and
- WACC – Sourced from the AER 2010 Determination[1]

Table 3.3.2, Table 3.3.3 and Table 3.3.4 demonstrate the sources from which Energex obtained the required information:

Table 3.3.2 - Data Sources - RIN Table 3.3.1: Regulatory Asset Base Values

Variable Code	Variable	Source
DRAB0101	Opening value	Preliminary Decision.
DRAB0102	Inflation addition	Australian Bureau of Statistics (ABS)
DRAB0103	Straight line depreciation	RFM
DRAB0104	Regulatory depreciation	Net of DRAB0102, DRAB0103
DRAB0105	Actual additions (recognised in RAB)	Regulatory Accounting Statements, ABS
DRAB0106	Disposals	Regulatory Accounting Statements, ABS
DRAB0107	Closing value for asset value	Calculated from DRAB0101 to DRAB0106

Table 3.3.3 - Data Sources - RIN Table 3.3.2: Asset value roll forward

Variable Code	Variable	Source
DRAB0201-7	Overhead network assets less than 33 kV	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB0301-7	Underground network assets less than 33 kV	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB0401-7	Distribution substations and transformers	Preliminary Decision, Regulatory Accounting Statements, ABS

[1] Final Decision – Queensland distribution determination 2010-11 to 2014-15, May 2010

Variable Code	Variable	Source
DRAB0501-7	Overhead network assets 33 kV and above	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB0601-7	Underground network assets 33 kV and above	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB0701-7	Zone substations and transformers	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB0801-7	Easements	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB0901-7	Meters	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1001-7	“Other” asset items with long lives	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1101-7	“Other” asset items with short lives	Preliminary Decision, Regulatory Accounting Statements, ABS

Table 3.3.4 - Data Sources - RIN Table 3.3.3: Total disaggregated RAB asset values

Variable Code	Variable	Source
DRAB1201	Overhead distribution assets less than 33 kV (wires and poles)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1202	Underground distribution assets less than 33 kV (cables, ducts etc)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1203	Distribution substations including transformers	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1204	Overhead assets 33 kV and above (wires and towers / poles etc)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1205	Underground assets 33 kV and above (cables, ducts etc)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1206	Zone substations	Preliminary Decision, Regulatory Accounting Statements, ABS

Variable Code	Variable	Source
DRAB1207	Easements	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1208	Meters	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1209	Other assets with long lives (please specify)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1210	Other assets with short lives (please specify)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB13	Value of Capital Contributions or Contributed Assets	Regulatory Accounting Statements and/or Supporting Workings

3.3.1.3 Methodology

- Energex has produced the SCS values for Regulatory Template 3.3 based on the RAB RFM closing value for 2013/14 from the AER's Preliminary Decision, including using actual information from the Regulatory Accounting Statements to produce the information required in the 2014/15 EB RIN. Each RAB asset category found in the RFM was then rolled up into the categories specified in the EB RIN.
- The RFM for Network Services (NS) was constructed from the RFM for SCS using historical RAB values and actual capex, adjusted by the connection assets capex values.
- For ACS, the RFM was based on the Preliminary Decision updated to include the actual capital expenditure (capex), asset disposals and capital contributions for 2014/15.

3.3.1.3.1 Assumptions

NS RAB values are a subset of SCS. RIN tables 3.3.2 and 3.3.3 for NS have been estimated by proportionately excluding the capex relating to connection assets from the relevant asset categories.

3.3.1.3.2 Approach

Standard Control Services

1) The RAB RFM was based on the Preliminary Decision. The RFM starts with the closing RAB values for the 2013/14 regulatory year and includes these values as the Opening Asset Value.

2) Data for 2014/15 was populated with actual amounts from the Regulatory Accounting Statements.

CPI was obtained from the ABS.

Capital contributions have not been included in the input sheet of the RAB RFM as Energex reports the RAB inclusive of these contributions and capital contributions rows in the input sheet of the RAB RFM are a deduction from gross capex. The input of these amounts in this model would cause the amounts to be inconsistent with those approved by the AER. Capital contributions have been calculated from the Regulatory Accounting Statements and are stated in variable DRAB13.

3) Using the input amounts in step 2) the RFM calculates the following for each RFM asset category for regulatory year 2015[2]:

   a. Nominal Opening Regulated Asset Base (equals 2014 closing Regulated Asset Base)

      These values are all nominal.

   b. Nominal Actual Inflation on Opening RAB

      Calculated as the Nominal Opening Regulated Asset Base multiplied by CPI.

   c. Nominal Actual Straight-line Depreciation

      Calculated as the sum of:

      i. the opening RAB depreciation inflated by CPI; and

      ii. depreciation incurred on prior year's capex, half WACC adjusted (assuming an average mid-year capitalisation date) and inflated by CPI

   d. Nominal Actual Gross Capex

      Calculated as the actual real term capex with half WACC adjustment, and adjusted by Actual CPI (1 year lagged). Capex is adjusted for movement in provisions relating to capex.

   e. Nominal Actual Disposal

      Calculated as the actual real term disposals with half WACC adjustment and adjusted by actual CPI (1 year lagged).

4) The amounts calculated in step 3) then formed the variables stated in RIN tables 3.3.1, 3.3.2 and 3.3.3. RIN table 3.3.1 contains the aggregated RAB amounts, Table 3.3.2 disaggregates these amounts into each asset category specified in the EB RIN and RIN table 3.3.3 contains the yearly average RAB value of the disaggregated asset categories.

[2] For full details of the calculations contained in the AER Roll Forward Model refer to the "Electricity distribution network service providers Roll forward model handbook, June 2008".

RIN Table 3.3.1 - Regulatory Asset Base Values

Aggregated RAB amounts are as set out in Table 3.3.5:

Table 3.3.5 – Aggregated RAB amounts

EB RIN Variable	RFM Calculated Amount
Opening value	Nominal Opening Regulated Asset Base
Inflation addition	Nominal Actual Inflation on Opening RAB
Straight line depreciation	Nominal Actual Straight-line Depreciation
Regulatory depreciation	Nominal Actual Inflation on Opening RAB + Nominal Actual Straight-line Depreciation
Actual additions (recognised in RAB)	Nominal Actual Gross Capex
Disposals	Nominal Actual Disposal
Closing value for asset value	Nominal Opening Regulated Asset Base (for next regulatory year)

RIN Table 3.3.2 - Asset Value Roll Forward

RIN Table 3.3.2 disaggregates each of the values in RIN table 3.3.1 into the individual asset categories specified in the EB RIN. These EB RIN asset categories are made up of one or more asset categories from the RFM. For the mapping of these refer to section 3.3.1.5 Explanatory Notes, Table 3.3.7.

5) The amounts in RIN Table 3.3.3 – Total disaggregated RAB asset values are calculated as the average of the opening and closing RAB totals for each EB RIN asset category for each year by applying the formula below[3].

$$Total\ Disaggreated\ RAB\ asset\ value_{y1} = \frac{Opening\ Value_{y1} + Closing\ Value_{y1}}{2}$$

The value of capital contributions is also contained in Table 3.3.3. These values have been taken directly from the annual Regulatory Accounting Statements.

Network Services (NS)

The AER has stated that Network Services (NS) are defined as "*a subset of Standard Control Services that excludes Connection Services, Metering services, Fee Based and Quoted Services and Public Lighting Services*".

Energex does not currently specifically report NS assets separately; as such the RAB for NS has been derived as a subset of the SCS RAB. The NS RFM is identical to SCS in its construction and calculations with only the inputs being changed in the following ways:

- The RFM opening values were adjusted to include only those values relating to NS.

[3] The formula is as per the EB RIN requirements, page 26 of the EB RIN Instructions and Definitions.

- The amounts for capex in the SCS RFM were adjusted to exclude any capex relating to connection assets to derive the NS values.

- Other than for metering and low voltage assets (which are considered wholly connection assets), the value of disposals relative to the SCS asset categories including connection assets is immaterial and have not been adjusted.

Adjustment to capex and forecast depreciation

1) Actual capex amounts for connection assets were sourced from a standard constructed assets WIP report. This report is the basis for capex reporting in the Regulatory Accounting Statements. The following activities in Table 3.3.6 were identified in this report as being related to connection assets:

Table 3.3.6 – Activities Related to Connection Assets

Capex Activities from Constructed Assets WIP Report	Description
C2010	Works required to connect individual Customers to the subtransmission (132,110 and 33 kV) and 11 kV backbone network.
C2510	Works to extend the network to connect domestic and rural customers, including subdivision works, excluding service connections.
C2550	Works to extend the network to connect commercial and industrial customers. The costs of Commercial/Industrial Customer requested extensions to the existing Distribution Network.
C2570	Construction of new services for new customers and upgraded services for existing customers. The cost of works involved in connecting customers to the distribution network. Also includes services, meters and relays

C2585 (Metering Type 6) has also been included in 2015 as a connection asset capital program activity. C2585 was newly set up to capture some of the spend that previously went to C2570. It includes asset types Metering LV and Metering LV – Load Control Devices.

2) The total capex relating to the above five activities is subtracted from those asset categories identified as containing connection assets. Low voltage services and metering assets are wholly excluded with the remaining capex subtracted from the relevant asset classes proportionate to their values.

3) The NS RFM then calculates the amounts for RIN tables 3.3.1 and 3.3.2 in an identical manner as described for SCS. Amounts for RIN table 3.3.3 were also calculated as the average of the opening and closing NS RAB totals for each EB RIN asset category.

Capital Contributions

4) The capital contributions for NS were calculated by reducing the values for SCS by the percentage seen in the overall RAB values between SCS and NS. The formula is as follows:

$$Capital\ Contributions_{NS} = \frac{RAB_{NS}}{RAB_{SCS}} \times Capital\ Contributions_{SCS}$$

Alternative Control Services

1) ACS has only existed in Energex from the 2011 regulatory year. From their inception the ACS in Energex have contained street lighting services, quoted and fee based services. As the AER only developed a RAB for street lighting services based on the limited building block approach, only street lighting services are included in the RFM, consistent with the EB RIN Instructions and Definitions.

2) CPI and WACC are based on those used for SCS.

3) Capital contributions for ACS were sourced directly from the Regulatory Accounting Statements and/or supporting workings.

3.3.1.4 Estimated Information

RIN tables 3.3.2 and 3.3.3 and DRAB13 Value of Capital Contributions or Contributed Assets for NS are considered estimated information.

3.3.1.4.1 Justification for Estimated Information

Energex has not captured the RAB for NS as it has not historically been required to report this category separately.

3.3.1.4.2 Basis for Estimated Information

The following amendments have been made to the SCS data to obtain the amounts for NS.

a. The asset category values used in the SCS RFM were adjusted to exclude values relating to connection assets.

b. The amounts for capex used in the SCS RFM were adjusted to exclude capex relating to connection assets. Disposals are only adjusted to exclude metering and low voltage services, as disposals in other asset categories were determined to be negligible.

c. The capital contribution stated for NS was estimated by applying the percentage of NS RAB over SCS RAB to the SCS capital contributions amount.

For a detailed explanation of the construction of NS RAB amounts please refer to section 3.3.1.3.2 Approach above.

Value of Capital Contributions for NS is estimated as a portion of the SCS capital contributions based on the percentage of the opening RAB value of total NS system assets over the opening RAB value of the total SCS system assets from the Assets (RAB) RFMs.

RIN Table 3.3.1 – Actual Information

- Previously all data for NS was considered Estimated Information as Energex had not captured the RAB for NS, as historically it had not been required to report this category separately. Energex relied on a number of assumptions to derive the NS RAB.

  However based on the following discussion, NS asset values will be Actual Information from this year onwards at the total level, that is, EB RIN Table 3.3.1 is Actual Information:

- Historically base year assets reported for NS were calculated using a percentage allocation of SCS assets and therefore this data was submitted as Estimated Information. This was regardless of yearly fixed assets movements being Actual Information or Estimated Information for subsequent years. It was considered that the data would always be deemed estimated due to the base year being Estimated Information. However, it is now noted that:
  - Capex is sourced from Energex's Financial systems;
  - The AER states in the EB RIN Instructions and Definitions (page 26);
  - "The allocated values for the 2013 Regulatory Year are to be used as the basis for rolling forward the RAB for Regulatory Years subsequent to the 2013 Regulatory Year."; and
  - The underlying source of the NS RAB is based on information from the AER's Preliminary Decision.

- Accordingly, Energex considers the total values in RIN Table 3.3.1 for 2014/15 are Actual Information.

RIN Tables 3.3.2 and 3.3.3 – Moving from Estimated to Actual

- Previously, it was recognised that connection assets capex identified based on the relevant activity codes, referred to in Table 3.3.6 above and the asset categories used in the RFM were not a one-to-one mapping. Connection assets were included in a number of asset categories within the RFM. To derive the NS capex for each of the asset categories within the RFM, total connection assets capex needed to be deducted from those asset categories on a proportionate basis. Therefore, RIN tables 3.3.2 and 3.3.3 are considered estimated information.

- However, from 1 July 2015, processes will be in place in the Ellipse system to enable fixed asset activity codes to be mapped to asset categories required in the EB RIN, including connection assets. This will mean that the RAB data for each of the NS EB RIN asset categories reported from this date will be considered actual.

3.3.1.5 Explanatory Notes

EB RIN Asset Category Definitions and Mapping

Table 3.3.7 - RAB EB RIN Asset Category Definitions and Mapping of EB RIN Asset Categories to Annual RIN Categories

EB RIN Asset Category	Definition	Mapped Energex Annual RIN Categories
Overhead network assets less than 33 kV (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Distribution Lines Low Voltage Services
Underground network assets less than 33 kV (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Distribution Cables
Distribution substations including transformers	Overhead and underground distribution substations. This includes ground mounted substations and pole mounted substations. This does not include zone substations.	Distribution Equipment Distribution Transformers
Overhead network assets 33 kV and above (wires and poles)	Assets used to conduct electricity from one point to another above ground. These include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	Overhead Sub-Transmission Lines
Underground network assets 33 kV and above (cables)	Assets used to conduct electricity from one point to another below ground. This includes cables, cable joints and other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	Underground Sub-Transmission Lines
Zone substations and transformers	Sites housing transformers involved in transforming power from high voltage input supply either directly from a TNSP or from Energex's own higher voltage lines - to distribution level voltages (e.g. 66 kV to 22 kV). This transformation can involve one step or multiple steps.	Substation Bays Substation Establishment Zone Transformers Distribution Substation Switchgear Buildings (System) Land (System)
Easements	An electricity easement is the right held by	Easements (System)

EB RIN Asset Category	Definition	Mapped Energex Annual RIN Categories
	Energex to control the use of land near aboveground and underground power lines and substations. It holds this right to ensure the landowner's safety and to allow staff access to work on the power lines at all times.	
Meters	An electricity meter is a device that measures the amount of electric energy consumed by a residence, business, or an electrically powered device	Metering
Other assets with long lives	Assets with expected asset lives greater than or equal to 10 years that are not: • Overhead Distribution Assets (Wires And Poles) • Underground Distribution Assets (Cables) • Distribution Substations Including Transformers • Zone Substations And Transformers • Easements • Meters	Communications Pilot Wires Street Lighting Other Equipment Control Centre - SCADA Buildings Land Equity Raising Costs
Other assets with short lives	Assets with expected asset lives less than 10 years that are not: • Overhead Distribution Assets (Wires And Poles) • Underground Distribution Assets (Cables) • Distribution Substations Including Transformers • Zone Substations And Transformers • Easements • Meters	Communications IT Systems Office Equipment & Furniture Motor Vehicles Plant & Equipment Research and Development

3.3.1.6 Accounting Policies

Energex changed its accounting policy in 2014/15 with respect to regulated revenue under and over recoveries. Previously, Energex accrued or deferred allowed regulated revenues through recognising the full amount of revenue allowed under its revenue determination and recognising any under (or over) recovery of this amount as an asset (or liability) to be adjusted in future revenues to be received from customers.

3.3.1.6.1 Nature of Change

There is no definitive guidance on the accounting treatment for regulatory receivables or provisions within existing accounting standards. However the Australian Accounting Standards Board (AASB) has commented, in response to the International Accounting Standards Board's (IASB) *Invitation to Comment ITC32 Reporting the Financial Effects of Rate Regulation*; that it has a view that, in most cases, regulatory deferral account balances do not meet the asset and liability recognition criteria as contained in the AASB's *Conceptual Framework*. To date, consensus has not been achieved and divergent views continue to be debated by the IASB.

The new policy, where the accrued (or deferred) revenues are not recognised, results in more reliable and relevant information to users as it reflects a closer correlation between market conditions, shareholder and other regulatory policies and profitability.

3.3.1.6.2 Impact of Change

As regulated revenue under (or over) recoveries are no longer recognised in the Statutory Accounts the treatment is in line with the Regulatory reporting.

There is no impact on assets (RAB) values reported.

3.3.2 Asset Lives

As per the AER (Australian Energy Regulator) requirements, Energex is providing the following variables regarding asset lives for Standard Control Services (SCS), Alternative Control Services (ACS) and Network Services (NS):

Table 3.3.4 Asset Lives

Table 3.3.4.1 Asset Lives – estimated service life of new assets

- **DRAB1401 – Overhead network assets less than 33kV (wires and poles)**
- **DRAB1402 – Underground network assets less than 33kV (cables)**
- **DRAB1403 – Distribution substations including transformers**
- **DRAB1404 – Overhead network assets 33kV and above (wires and towers / poles etc.)**
- **DRAB1405 – Underground network assets 33kV and above (cables, ducts etc.)**
- **DRAB1406 – Zone substations and transformers**
- **DRAB1407 – Meters**
- **DRAB1408 – "Other" assets with long lives**
- **DRAB1409 – "Other" assets with short lives**

Table 3.3.4.2 Asset Lives – estimated residual service life

- **DRAB1501 – Overhead network assets less than 33kV (wires and poles)**
- **DRAB1502 – Underground network assets less than 33kV (cables)**
- **DRAB1503 – Distribution substations including transformers**
- **DRAB1504 – Overhead network assets 33kV and above (wires and towers / poles etc.)**
- **DRAB1505 – Underground network assets 33kV and above (cables, ducts etc.)**
- **DRAB1506 – Zone substations and transformers**
- **DRAB1507 – Meters**
- **DRAB1508 – "Other" assets with long lives**
- **DRAB1509 – "Other" assets with short lives**

These variables are a part of worksheet 3.3 – Assets (RAB) and have all been calculated using the AER Asset Life Roll Forward Model (RFM).

Data stated for NS is considered estimated information.

All data stated for SCS and ACS is considered actual information.

3.3.2.1 Consistency with EB RIN Requirements

The AER requires Energex report asset lives information in accordance with the asset categories defined in the EB RIN templates. The definitions of these asset categories can be seen in BoP 3.3.1 Asset (RAB) Values, section 3.3.1.5 Explanatory Notes, Table 3.3.7.

Table 3.3.8 demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.3.8 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
New assets are assets installed in the most recent regulatory reporting year. The expected service life of new assets is the estimated period after installation of a new asset during which the asset will be capable of delivering the same effective service as it could at its installation date. This may not align with the asset's financial or tax life	Energex has stated the service life of new assets in the RAB based on the RAB RFM from the AER's – Preliminary Decision Energex Determination 2015-16 to 2019-20 (Preliminary Decision). This represents the estimated time where the asset is capable of delivering the same effective service as it could at installation date.
Energex must report a current estimation of the weighted average remaining time expected that an asset class (as per DRAB1401 to DRAB1409) will deliver the same effective service as that asset class did at its installation date.	Energex has stated the estimated residual service life of all RAB asset categories as the weighted average of all assets contained in that category. Similar to the estimated service lives, these figures are based on the Preliminary Decision. All weighted averages have been calculated on the assets' share of the RAB and their expected asset lives. Energex has also divided asset life data into NS, SCS and ACS. This was done in line with the methodology outlined for RAB values (for details please refer to section **Error! Reference source not found.**).

3.3.2.2 Sources

Data has been sourced from the Preliminary Decision. Additional inputs have been sourced as follows:

- CPI information – Sourced from the Australian Bureau of Statistics (ABS) data series A2325846C (eight capital cities from March to March) in line with the AER approach and regulatory reporting;
- Capex and disposal – Sourced from the annual Regulatory Accounting Statements; and
- WACC – Sourced from the 2010 Determination.

Table 3.3.9 and Table 3.3.10 below demonstrate the sources from which Energex obtained the required information:

Table 3.3.9 - Data Sources RIN Table 3.3.4.1 Asset Lives: Estimated Service Life of New Assets

Variable Code	Variable	Source
DRAB1401	Overhead network assets less than 33kV (wires and poles)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1402	Underground network assets less than 33kV (cables)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1403	Distribution substations including transformers	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1404	Overhead network assets 33kV and above (wires and towers / poles etc)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1405	Underground network assets 33kV and above(cables, ducts etc)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1406	Zone substations and transformers	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1407	Meters	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1408	"Other" assets with long lives	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1409	"Other" assets with short lives	Preliminary Decision, Regulatory Accounting Statements, ABS

Table 3.3.10 - Data Sources RIN Table 3.3.4.2 Asset Lives: Estimated Residual Service Life

Variable Code	Variable	Source
DRAB1501	Overhead network assets less than 33kV (wires and poles)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1502	Underground network assets less than 33kV (cables)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1503	Distribution substations including transformers	Preliminary Decision, Regulatory Accounting Statements, ABS

Variable Code	Variable	Source
DRAB1504	Overhead network assets 33kV and above (wires and towers / poles etc)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1505	Underground network assets 33kV and above (cables, ducts etc)	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1506	Zone substations and transformers	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1507	Meters	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1508	"Other" assets with long lives	Preliminary Decision, Regulatory Accounting Statements, ABS
DRAB1509	"Other" assets with short lives	Preliminary Decision, Regulatory Accounting Statements, ABS

3.3.2.3 Methodology

Energex has produced the figures for the expected service life of new assets and the residual service life of assets based on the RFMs from the Preliminary Decision. These RFMs were updated for the 2015 using actual information (actual capex and asset disposals) from the Regulatory Accounting Statements.

3.3.2.3.1 Assumptions

Standard service life of RAB assets is constant and equal to those specified in the Preliminary Decision.

3.3.2.3.2 Approach

Standard Control Services

1) The estimated service life of new assets was calculated using the standard service life published in the Preliminary Decision RFM. This service life was applied to 2015. The asset life categories in the 2010 Determination RFM were then aggregated into the categories required for the EB RIN. The aggregation used a weighted average of each of the applicable asset categories, weighted by their 2015 opening RAB value. For the mapping of the Preliminary Decision RFM asset categories to the EB RIN categories refer to BoP 3.3.1 Asset (RAB) Values, section 3.3.1.5 Explanatory Notes,

2) The residual service life of RAB assets was calculated using the Asset Life RFM template used for the Preliminary Decision using estimated standard lives for

additions and residual lives of existing assets. The calculations were extended to 2015 to complete the EB RIN data requirements. This template relies on information calculated in the extended RAB RFM for SCS, ACS and NS, as detailed in Basis of Preparation for Assets (RAB) Values. The extended Asset Life RFM template extracts the following information found in the RAB RFM for each asset category and regulatory year:

a. Standard Asset Life;
b. Opening RAB Value (2010);
c. Opening RAB Residual Asset Life (2010);
d. Acquisitions (assumed average mid-year capitalisation and adjusted for half year WACC);
e. Disposals (assumed average mid-year disposal and adjusted for half year WACC);
f. Depreciation; and
g. Adjustments (adjustments made in 2015 for the difference between actual and forecast capex for 2010).

3) The average residual life for each asset class is calculated by rolling forward the RAB values from the prior year. This is calculated as the weighted average of:

a. The prior year's average residual life minus one; and
b. The standard life of any new acquisitions.
c. The weightings are based on the RAB value of the current year's assets (prior year RAB minus disposals, depreciation and applicable adjustments) and the newly acquired assets.

4) With the residual average asset lives calculated for each regulatory year, the asset categories are then combined into the EB RIN asset categories. The EB RIN residual asset life is calculated for each year as the average of the RFM asset lives weighted by the yearly RAB value of each RFM asset category. The mapping of the RFM asset categories to the EB RIN asset categories can be found in BoP 3.3.1 Asset (RAB) Values, section 3.3.1.5 Explanatory Notes, Table 3.3.7.

Network Services

5) NS are defined as a subset of SCS. A separate RAB RFM has been developed on the assumptions in relation to NS contained in Basis of Preparation for Assets (RAB) Values. This is identical to SCS with the exclusion of those assets specified by the AER in the definition of Network Services contained in the Instructions and Definitions for the EB RIN (e.g. Metering assets). For details of the construction of the NS RAB RFM refer to Basis of Preparation for Assets (RAB) Values.

   The Asset Life RFM for NS is constructed in an identical manner to that for SCS however it draws its data from the NS RAB RFM. As such the methodology for preparing the estimated service life of new assets and the residual service life of RAB assets is identical to steps 1 – 4 in SCS above.

Alternative Control Services

6) For Energex, ACS asset categorisation starts from 2011 and since its inception only includes Street Lighting assets. A separate RFM was developed for ACS using the template supplied by the AER for the Preliminary Decision. This model was then updated using actual Street Lighting asset data for 2015 sourced from the Regulatory Accounting Statements.

   In a similar approach to SCS and NS, the developed RFM was used as the source information to calculate the estimated service life of new assets and residual service life of assets for ACS using an Asset Life RFM. The methodology of calculating these variables was identical to SCS and NS.

   For the details of the ACS RFM refer to Basis of Preparation for Assets (RAB) Values.

3.3.2.4 Estimated Information

- All variables for NS are considered estimates, as RAB information for NS is estimated.

3.3.2.4.1 Justification for Estimated Information

- Energex historically has not captured RAB information separately for NS.

3.3.2.4.2 Basis for Estimated Information

Network Services

- The NS standard asset lives were estimated by removing connection assets from the figures developed for SCS. The RAB RFM developed for NS was based on the SCS RFM but excluded connection assets in the 2005 base year and each subsequent year’s capex and disposals. For details on these calculations refer to Basis of Preparation for RAB Values.

- Residual asset lives were then calculated in an identical manner to SCS by extracting the values from the RFM for NS and rolling forward the residual asset life figures.

3.4 OPERATIONAL DATA

3.4.1 Energy Delivery

The AER requires Energex to provide the following information relating to the delivery of energy:

3.4.1 Energy Delivery

- DOPED01 – Total energy delivered

3.4.1.1 Energy grouping - delivery by chargeable quantity

- DOPED0201 – Energy Delivery where time of use is not a determinant
- DOPED0202 – Energy Delivery at On-peak times
- DOPED0203 – Energy Delivery at Shoulder times
- DOPED0204 – Energy Delivery at Off-peak times
- DOPED0205 – Controlled load energy deliveries
- DOPED0206 – Energy Delivery to unmetered supplies

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

- DOPED0301 – Energy into DNSP network at On-peak times
- DOPED0302 – Energy into DNSP network at Shoulder times
- DOPED0303 – Energy into DNSP network at Off-peak times
- DOPED0304 – Energy received from TNSP and other DNSPs not included in the above categories

3.4.1.3. Energy - received into DNSP system from embedded generation (EG) by time of receipt

- DOPED0401 – Energy into DNSP network at On-peak times from non-residential EG
- DOPED0402 – Energy into DNSP network at Shoulder times from non-residential EG
- DOPED0403 – Energy into DNSP network at Off-peak times from non-residential EG
- DOPED0404 – Energy received from EG not included in above categories from non-residential EG
- DOPED0405 – Energy into DNSP network at On-peak times from residential EG
- DOPED0406 – Energy into DNSP network at Shoulder times from residential EG
- DOPED0407 – Energy into DNSP network at Off-peak times from residential EG
- DOPED0408 – Energy received from EG not included in above categories from residential EG

3.4.1.4. Energy grouping - customer type or class

- DOPED0501 – Residential customers energy deliveries
- DOPED0502 – Non-residential customers not on demand tariffs energy deliveries
- DOPED0503 – Non-residential low voltage demand tariff customers energy deliveries
- DOPED0504 – Non-residential high voltage demand tariff customers energy deliveries
- DOPED0505 – Other Customer Class Energy Deliveries

These variables are a part of Regulatory Template 3.4 – Operational Data.

Information reported is a combination of Actual Information and Estimated Information.

3.4.1.1 Consistency with EB RIN Requirements

Table 3.4.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER:

Table 3.4.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energy delivered is the amount of electricity transported out of Energex's network in the relevant Regulatory Year (measured in GWh). It must be the energy metered or estimated at the customer charging location rather than the import location from the TNSP. Energy delivered must be actual energy delivered data, unless this is unavailable.	Energy delivered has been measured at the customer charging location.
Peak, shoulder and off-peak periods relate to Energex's own charging periods.	Energex only uses on and off-peak periods. Data for shoulder periods is reported as blank.
Energex must only report 'Energy Delivery where time of use is not a determinant' (DOPED0201) for Energy Delivery that was not charged for peak, shoulder or off-peak periods.	All data for DOPED0201 was not charged based on time of use.
Energex must report energy input into its network as measured at supply points from the TNSP and other DNSPs in accordance with the definitions provided in chapter 9.	All energy supplied has been measured at supply points from Powerlink and other DNSPs.
Energex is required to report energy received from Non-residential Embedded Generation by time of receipt. Energex is required to report back cast energy received from Residential Embedded Generation only if it records data for these variables (DOPED0405–DOPED0408)	Only solar generation has been reported in DOPED0405
Energex must report energy delivered in accordance with the category breakdown as per the definitions provided in chapter 9. The category breakdown must be consistent with the customer types reported in RIN Table 5.2.1	The customer types are consistent to those used in RIN Table 3.4.2[4]

[4] The EB RIN regulatory templates were revised in 2014. RIN table 5.2.1 is identified as 3.4.2 in the revised regulatory templates.

3.4.1.2 Sources

Table 3.4.2, Table 3.4.3, Table 3.4.4,

Table 3.4.5 and Table 3.4.6**Error! Reference source not found.** demonstrate the sources from which Energex obtained the required information:

Table 3.4.2 - Data Sources: RIN Table 3.4.1: Energy Delivery – Total Energy Delivered

Variable Code	Variable	Unit	Source
DOPED01	Total energy delivered	GWh	PEACE

Table 3.4.3 - Data Sources: RIN Table 3.4.1.1: Energy grouping - Delivery by chargeable quantity

Variable Code	Variable	Unit	Source
DOPED0201	Energy Delivery where time of use is not a determinant	GWh	PEACE
DOPED0202	Energy Delivery at On-peak times	GWh	PEACE and MV90
DOPED0203	Energy Delivery at Shoulder times	GWh	-
DOPED0204	Energy Delivery at Off-peak times	GWh	PEACE and MV90
DOPED0205	Controlled load energy deliveries	GWh	PEACE
DOPED0206	Energy Delivery to unmetered supplies	GWh	PEACE

Table 3.4.4 - Data Sources: RIN Table 3.4.1.2: Energy – received from TNSP and other DNSPs by time of receipt

Variable Code	Variable	Unit	Source
DOPED0301	Energy into DNSP network at On-peak times	GWh	Network Load Forecasting (NLF) Database
DOPED0302	Energy into DNSP network at Shoulder times	GWh	-
DOPED0303	Energy into DNSP network at Off-peak times	GWh	NLF
DOPED0304	Energy received from TNSP and other DNSPs not included in the above categories	GWh	NLF

Table 3.4.5 - Data Sources: RIN Table 3.4.1.3 Energy – received into DNSP system from Embedded Generation by time of receipt

Variable Code	Variable	Unit	Source
DOPED0401	Energy into DNSP network at On-peak times from non-residential embedded generation	GWh	NLF
DOPED0402	Energy into DNSP network at Shoulder times from non-residential embedded generation	GWh	-
DOPED0403	Energy into DNSP network at Off-peak times from non-residential embedded generation	GWh	NLF
DOPED0404	Energy received from embedded generation not included in above categories from non-residential embedded generation	GWh	-
DOPED0405	Energy into DNSP network at On-peak times from residential embedded generation	GWh	PEACE
DOPED0406	Energy into DNSP network at Shoulder times from residential embedded generation	GWh	-
DOPED0407	Energy into DNSP network at Off-peak times from residential embedded generation	GWh	-
DOPED0408	Energy received from embedded generation not included in above categories from residential embedded generation	GWh	-

Table 3.4.6 - Data Sources: RIN Table 3.4.1.4 Energy grouping – customer type or class

Variable Code	Variable	Unit	Source
DOPED0501	Residential customers energy deliveries	GWh	PEACE
DOPED0502	Non-residential customers not on demand tariffs energy deliveries	GWh	PEACE

Variable Code	Variable	Unit	Source
DOPED0503	Non-residential low voltage demand tariff customers energy deliveries	GWh	PEACE
DOPED0504	Non-residential high voltage demand tariff customers energy deliveries	GWh	PEACE
DOPED0505	Other Customer Class Energy Deliveries	GWh	PEACE

3.4.1.3 Methodology

Annual energy data in the Energex Network can be classified into two categories, based on both the energy flow features and the 2014/15 Economic Benchmarking RIN requirement:

- Energy Delivered (ie. kWh conveyed by Energex to end users)
- Energy Purchased (ie; kWh injected into the Energex Network)

Energy delivered is reported in RIN tables 3.4.1.1 and 3.4.1.4, while energy purchased is reported in RIN tables 3.4.1.2 and 3.4.1.3. Each of these figures is broken down into the categories specified by the AER.

3.4.1.3.1 Assumptions

Energex applied the following assumptions to obtain the required information:

- It is assumed that all residential solar power is generated inside peak periods and metered. Due to the sunlight times there is little generation outside these periods.
- Commercial solar PV is un-metered. All the energy generated in this group is assumed to be consumed internally so that its impacts on energy and peak demand are covered by the monthly recorded billing data.

3.4.1.3.2 Approach

Total Energy Delivered

The total energy delivered by Energex to customers was extracted directly from the Energex billing system (PEACE) and aggregated for the Regulatory Year. A large proportion of Energex customers (residential and small business accounting for around 95%) are quarterly read accumulation metering and Energex is required to estimate the final end of financial year total until October each year.

RIN table 3.4.1.1: Energy grouping – delivery by chargeable quantity

The calculation of each line item is summarised in the Table 3.4.7 below and figures were disaggregated using the network tariff codes. The data was separated into the separate time periods using data inherent in the source systems. Energex does not use a shoulder period and therefore cells for these variables have been left blank. Data in this table was sourced from the Energex billing system (PEACE).

Table 3.4.7 - Method for calculating delivery by chargeable quantity

Variable Code	Variable	Calculation methodology
DOPED0201	Energy Delivery where time of use is not a determinant	Sum of all residential sales excluding controlled load and solar. The residual value of energy delivered (total energy delivered DOPED01 minus the total of DOPED0202-6) was also added to this variable.
DOPED0202	Energy Delivery at On-peak times	Calculate the On-peak-times usage ratios by using the peak (between either 7am – 9pm or 7am – 11pm weekdays) over the total energy delivered to half hourly metered customers sourced from monthly MV90 reports. The ratios then are applied to those half hourly metered customer groups (ie; the following NTCs: 1000, 2000, 2500, 3000, 4000, 4500, 8000, 8100, 8300, 8500 and 8800) sourced from PEACE system to calculate the total on-peak-time energy delivery.
DOPED0203	Energy Delivery at Shoulder times	Not applicable.
DOPED0204	Energy Delivery at Off-peak times	The same methodology (described in DOPED0202) is used to calculate the off-peak-time ratios (which are basically the residuals of the on-peak-time ratios) for half hourly metered customers. The ratios then are applied to those half hourly metered customer groups (ie; the following NTCs: 1000, 2000, 2500, 3000, 4000, 4500, 8000, 8100, 8300, 8500 and 8800) sourced from PEACE system to calculate the total off-peak-time energy delivery.
DOPED0205	Controlled load energy deliveries	Sum of energy delivered to controlled load customers, calculated as the sum of NTCs 9000 and 9100.
DOPED0206	Energy Delivery to unmetered supplies	Sum of street lighting based on NTC 9600.

RIN table 3.4.1.2: Energy – received from TNSP and other DNSPs by time of receipt

Data in this table was sourced from the Network Load Forecasting database (which is an extract of the TOHT metering system) as detailed in **Error! Not a valid bookmark self-reference.** below:

Table 3.4.8 - Method for calculating RIN Table 3.4.1.2 Energy – received from TNSP and other DNSPs by time of receipt

Variable Code	Variable	Calculation methodology
DOPED0301	Energy into DNSP network at On-peak times	Sum of all energy received to Energex connection points between 7am – 9pm weekdays.
DOPED0302	Energy into DNSP network at Shoulder times	Not applicable.
DOPED0303	Energy into DNSP network at Off-peak times	Sum of all energy received to Energex connection points outside 7am – 9pm (this includes all times on weekends and public holidays).
DOPED0304	Energy received from TNSP and other DNSPs not included in the above categories	Sum of all energy received from and/or exported to other DNSPs not listed in DOPED0301 ~ DOPED0303 (For example, Kirra zone substation owned by Energex occasionally receives/exports energy from/to New South Wales) over a financial year. Because the direction of electricity conveyed can flow both (in and out) ways, the net impacts may show positive or negative values (it was positive for the 2014/15 year, indicating energy flowing-in).

RIN table 3.4.1.3: Energy – received into DNSP system from Embedded Generation by time of receipt

Data in this table was sourced from the Network Load Forecasting database as detailed in Table 3.4.9:

Table 3.4.9 - Method for calculating RIN Table 3.4.1.3 Energy – received into DNSP system from Embedded Generation by time of receipt

Variable Code	Variable	Calculation methodology
DOPED0401	Energy into DNSP network at On-peak times from non-residential embedded generation	Sum of all energy received from embedded generators and Queensland Rail trains (regenerative braking) between 7am – 9pm weekdays.
DOPED0402	Energy into DNSP network at Shoulder times from non-	Not applicable.

Variable Code	Variable	Calculation methodology
	residential embedded generation	
DOPED0403	Energy into DNSP network at Off-peak times from non-residential embedded generation	Sum of all energy received from embedded generators and Queensland Rail trains (regenerative braking) outside 7am – 9pm (this includes all times on weekends and public holidays).
DOPED0404	Energy received from embedded generation not included in above categories from non-residential embedded generation	Not applicable.
DOPED0405	Energy into DNSP network at On-peak times from residential embedded generation	Sum of all solar photovoltaic generated injections. It is assumed that all solar power is generated inside peak periods. Due to the sunlight times there is little generation outside these times.
DOPED0406	Energy into DNSP network at Shoulder times from residential embedded generation	Not applicable.
DOPED0407	Energy into DNSP network at Off-peak times from residential embedded generation	Not applicable.
DOPED0408	Energy received from embedded generation not included in above categories from residential embedded generation	Not applicable.

RIN table 3.4.1.4: Energy grouping – customer type or class

Data in this table was sourced from the Energex billing system (PEACE) as detailed in Table 3.4.10:

Table 3.4.10 - Method for calculating RIN Table 3.4.1.4 Energy grouping: customer type or class

Variable Code	Variable	Calculation methodology
DOPED0501	Residential customers energy deliveries	Sum of energy deliveries to all residential customers plus energy delivered to controlled load NTCs. This included the following NTCs: 8400, 8900, 9000 and 9100. The residual value of energy delivered (total energy delivered DOPED01 minus the total of DOPED0502-5) was also added to this variable.
DOPED0502	Non-residential customers not on demand tariffs energy deliveries	Calculated as the sum of energy delivered to NTCs 8500 and 8800. This includes all non-residential customers not charged on demand tariffs.
DOPED0503	Non-residential low voltage demand tariff customers energy deliveries	Calculated as the sum of energy delivered to NTCs 8100 and 8300, which are categorised as demand large (suitable for demand between 250kVA to 1MVA) and demand small (suitable for demand up to 250kVA) customers.
DOPED0504	Non-residential high voltage demand tariff customers energy deliveries	Calculated as the sum of NTCs up to 8000. This includes all customers with a high voltage network connection.
DOPED0505	Other Customer Class Energy Deliveries	Same figure as DOPED0206. Please refer to DOPED0206 calculation methodology.

3.4.1.4 Estimated Information

- All energy delivered which includes all the variables in RIN tables 3.4.1, 3.4.1.1 and 3.4.1.4;
- Energy purchased data on Residential Embedded Generation at On-peak Times (ie. DOPED0405 in RIN table 3.4.1.3).

3.4.1.4.1 Justification for Estimated Information

- The energy delivered data is sourced from the PEACE Billing Software. It is quarterly billed so the data is not available for 3 to 4 months due to the meter reading processes. This means the data will not be finalised until the mid-October for a reported financial year.
- Energy purchased data on Residential Embedded Generation at On-peak Times record the total energy injected into the Energex Network system provided by domestic PV generation. The data also comes from PEACE and therefore, is estimated due to the same reason discussed above.

3.4.1.4.2 Basis for Estimated Information

- Energex constructs a series of Monthly Energy Sales Models for different tariff groups (eg. T4000s large non-domestic customers, T8000s medium/small non-domestic customers and T8400 domestic customers).

- These typical econometric models use key drivers such as Queensland Gross State Product (GSP), the number of new customer connections and weather variables (eg; temperature and relative humidity indices). They systematically analyse the underlying driving forces and try to capture the impacts of those key drivers on energy sales in both the short and long term. It therefore, provides a powerful tool for Energex to do energy forecasts.

- If the actual monthly data is available for a part of the year (for example, actual billing data are available for July ~ March), this data will be added to the estimated energy sales for the portion of the financial year that is unavailable to produce the full financial year figure. The energy sales for the unavailable portion of the financial year will be estimated based on those econometric models. If necessary, some adjustments may also be included in estimation based on the latest available information.

3.4.2 Customer Numbers

The AER requires Energex to provide the following variables relating to customer numbers:

RIN Table 3.4.2.1 Distribution customer numbers by customer type

- **DOPCN0101 – Residential customer numbers**
- **DOPCN0102 – Non-residential customers not on demand tariff customer numbers**
- **DOPCN0103 – Low voltage demand tariff customer numbers**
- **DOPCN0104 – High voltage demand tariff customer numbers**
- **DOPCN0105 – Unmetered Customer Numbers**
- **DOPCN0106 – Other Customer Numbers**
- **DOPCN01 – Total customer numbers**

RIN Table 3.4.2.2 Distribution customer numbers by location on the network

- **DOPCN0201 – Customers on CBD network**
- **DOPCN0202 – Customers on Urban network**
- **DOPCN0203 – Customers on Short rural network**
- **DOPCN0204 – Customers on Long rural network**
- **DOPCN02 – Total customer numbers**

These variables are a part of Regulatory Template 3.4 – Operational Data.

All values are Actual Information.

3.4.2.1 Consistency with EB RIN Requirements

Table 3.4.11 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER:

Table 3.4.11 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Distribution Customers for a Regulatory Year are the average number of active National Meter Identifiers (NMIs) in Energex's network in that year. The average is calculated as the average of the number of NMIs on the first day of the Regulatory Year and on the last day of the Regulatory Year.	Customer numbers have been calculated as the average of the beginning and end of year figures.
Each NMI is counted as a separate customer. Both energised and de-energised NMIs must be counted. Extinct NMIs must not be counted.	Energex has calculated all customer numbers as the number of “active” NMIs inclusive of both “energised” and “de-energised” NMIs.
Energex must report Customer Numbers broken down by customer class in accordance with the categorisations specified by the AER.	Customer numbers have been broken down by customer type using the definitions specified by the AER.

3.4.2.2 Sources

Three key sources of data were used to produce the number of customers by customer type. PEACE, EMAS/NFM and SLIM as detailed in Table 3.4.12 below:

Table 3.4.12 – Data sources for customers by customer type

RIN Table 3.4.2.1 Distribution customer numbers by customer type or class			
Variable Code	**Variable**	**Unit**	**Source**
DOPCN0101	Residential customer numbers	number	PEACE
DOPCN0102	Non-residential customers not on demand tariff customer numbers	number	PEACE
DOPCN0103	Low voltage demand tariff customer numbers	number	PEACE
DOPCN0104	High voltage demand tariff customer numbers	number	PEACE
DOPCN0105	Unmetered Customer Numbers	number	SLIM
DOPCN0106	Other Customer Numbers	number	Not Applicable
DOPCN01	Total customer numbers	number	PEACE and SLIM (UMS only)

All data relating to customer numbers broken down by location on the network was sourced from the Energex NFM system as detailed in Table 3.4.13 below:

Table 3.4.13 – Data sources for customers by network location

RIN Table 3.4.2.2 Distribution customer number by location on the network			
Variable Code	**Variable**	**Unit**	**Source**
DOPCN0201	Customers on CBD network	number	NFM / EMAS
DOPCN0202	Customers on Urban network	number	NFM / EMAS
DOPCN0203	Customers on Short rural network	number	NFM / EMAS
DOPCN0204	Customers on Long rural network	number	N / A
DOPCN02	Total customer numbers	number	NFM / EMAS

3.4.2.3 Methodology

The Energex customer numbers are reported from two separate systems as the breakdown of customers by customer type and network location are stored in Energex's PEACE and NFM systems respectively. The total customer numbers in these two systems do not match due to historical reconciliation issues between these two systems. This discrepancy and Energex's efforts to reconcile these figures is detailed in the Not applicable.

Explanatory Notes section of this Basis of Preparation.

The customer numbers extracted from PEACE and NFM include "active" and "de-energised" customers.

Network Tariff codes have been used to split the customers across DOPCN0102, DOPCN0103, and DOPCN0104. Refer to Table 3.4.14 - Energex Network Tariff Code Classifications to see exactly how it was done.

3.4.2.3.1 Assumptions

No assumptions were applied.

3.4.2.3.2 Approach

RIN Table 3.4.2.1 Distribution customer numbers by customer type or class

This approach required a count of PEACE customers and a report from SLIM to generate all data required. These reports extracted the number of NMIs that were classed only as active and were energised or de-energised.

1) The total end of year customer numbers for residential vs non-residential customers was extracted from PEACE and split using the corresponding network tariff codes.

2) NTC was used to determine the customer voltage. Refer to Table 3.4.14 - Energex Network Tariff Code Classifications for more details.

3) SLIM provided the count of UMS NMIs (not Street Lights or government lighting (rate 1, 2, 3). Government owned Rate 8 street lighting was also excluded. Rate 8 privately owned lighting was included.

4) No customers fell into the "Other customers" (DOPCN0106) classification and as such these figures are zero. The AER have advised previously they do not expect data to be provided here.

RIN Table 3.4.2.2 Distribution customer number by location on the network

1) The customer numbers broken down by their location on the network are stored on the Energex NFM / EMAS systems. Energex does not have any customers on long rural networks and therefore all rural flagged customers are classed as short rural.

2) Average customer figures were then calculated for each variable DOPCN0201-3 - the total from the start and end of the regulatory periods was used (e.g. snapshots from 1/7/14 and 30/6/15 were divided by 2). De-en customers were added in after (they are not currently included in our SAIDI/SAIFI/CAIDI customer numbers). UMS are also excluded from these totals and have not been added in.

3) The variable "DOPCN02 – Total customer numbers" was then calculated as the sum of customers in each network location.

3.4.2.4 Estimated Information

No Estimated Information was reported.

3.4.2.4.1 Justification for Estimated Information

Not applicable.

3.4.2.4.2 Basis for Estimated Information

Not applicable.

3.4.2.5 Explanatory Notes

Reconciliation of total customer figures between 3.4.2.1 and 3.4.2.2

Historically, the total number of customers broken down by customer type (RIN table 3.4.2 1) does not match the total broken down by location on the network (RIN table 3.4.2.2). This problem is due to reconciliation issues between the PEACE (Market CIS system) and NFM/MARS/EMAS (Network Systems) and has been ongoing for Energex for the last several years. Energex has worked hard to align these figures over time and the difference between the two sources typically reduces through the regulatory years. A number of issues were identified as discrepancies between the two systems:

- Timing between systems when counting customers (e.g. if 1,000 new customers were made 'Active' today (from 'Greenfield'), the Network Systems don't know about it until the following day – so these NMIs would not be counted in the Network Systems – whereas they would be included in the PEACE figures).

- As an example of the differences improving over time, this regulatory period (14-15), the difference between the systems is 1,343 customers (PEACE is higher). In 2011-12, we reported 1,333,670 NMIs from PEACE and 1,339,700 from NFM / EMAS (a difference of 6030 NMIs).

Table 3.4.14 - Energex Network Tariff Code Classifications

Network Tariff Code (NTC)	Type 1 Classification	Type 2 Classification
7600	Domestic	LV – residential
8400	Domestic	LV – residential
8900	Domestic	LV – residential
9000	Domestic	LV – residential
9100	Domestic	LV – residential
1000	Non-domestic	HV Demand
2000	Non-domestic	HV Demand
2500	Non-domestic	HV Demand
3000	Non-domestic	HV Demand
3500	Non-domestic	HV Demand
4000	Non-domestic	HV Demand
4500	Non-domestic	HV Demand
8000	Non-domestic	HV Demand
8100	Non-domestic	LV Demand - non-residential
8200	Non-domestic	LV Demand - non-residential
8300	Non-domestic	LV Demand - non-residential
8500	Non-domestic	LV - non-residential non demand
8600	Non-domestic	LV - non-residential non demand
8700	Non-domestic	LV - non-residential non demand
8800	Non-domestic	LV - non-residential non demand
9200	Non-domestic	UMS – Not applicable to Energex
9300	Non-domestic	UMS – Streetlights (public lighting) - excluded
9400	Non-domestic	UMS – Not applicable to Energex
9500	Non-domestic	UMS – Watchman Lights, included

Network Tariff Code (NTC)	Type 1 Classification	Type 2 Classification
9600	Non-domestic	UMS – Body Corporate Lighting etc., included
7500	Solar	Excluded (always with a primary NTC)
9700	Solar	Excluded (always with a primary NTC)
9800	Solar	Excluded (always with a primary NTC)
9900	Solar	Excluded (always with a primary NTC)

3.4.3 Annual System Maximum Demand

The AER requires Energex to provide the following variables relating to annual system maximum demand:

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

- **DOPSD0101 - Non-coincident Summated Raw System Annual Maximum Demand**
- **DOPSD0102 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0103 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE**
- **DOPSD0104 - Coincident Raw System Annual Maximum Demand**
- **DOPSD0105 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0106 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE**

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

- **DOPSD0107 - Non-coincident Summated Raw System Annual Maximum Demand**
- **DOPSD0108 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0109 - Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE**
- **DOPSD0110 - Coincident Raw System Annual Maximum Demand**
- **DOPSD0111 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0112 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE**

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

- **DOPSD0201 - Non–coincident Summated Raw System Annual Maximum Demand**
- **DOPSD0202 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0203 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE**
- **DOPSD0204 - Coincident Raw System Annual Maximum Demand**
- **DOPSD0205 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0206 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE**

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

- **DOPSD0207 - Non–coincident Summated Raw System Annual Maximum Demand**
- **DOPSD0208 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0209 - Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE**
- **DOPSD0210 - Coincident Raw System Annual Maximum Demand**
- **DOPSD0211 - Coincident Weather Adjusted System Annual Maximum Demand 10% POE**
- **DOPSD0212 - Coincident Weather Adjusted System Annual Maximum Demand 50% POE**

These variables are part of Regulatory Template 3.4 – Operational Data.

All information is Actual Information.

3.4.3.1 Consistency with EB RIN Requirements

Table 3.4.15 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.4.15 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
RIN Tables 3.4.3.1 to 3.4.3.4 must be completed in accordance with the definitions in chapter 9.	Demonstrated in section 3.4.3.3.2 (Approach).
Energex must provide inputs for these cells if it has calculated historical Weather Adjusted Maximum Demand.	Demonstrated in section 3.4.3.3.2 (Approach).
For RIN Table 3.4.3.1 the coincident and non-coincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% Probability of Exceedance (POE) levels.	Demonstrated in section 3.4.3.3.2 (Approach).
For RIN Table 3.4.3.2 the coincident and non-coincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.	Demonstrated in section 3.4.3.3.2 (Approach).
For RIN Table 3.4.3.3 the coincident and non-coincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.	Demonstrated in section 3.4.3.3.2 (Approach).
For RIN Table 3.4.3.4 the coincident and non-coincident Maximum Demands must be reported raw (or unadjusted) and Weather Adjusted at the 10% and 50% POE levels.	Demonstrated in section 3.4.3.3.2 (Approach).
Coincident Raw System Annual Maximum Demand is the actual, unadjusted (i.e. not weather normalised) summation of actual raw demands for the requested asset level (either the zone substation or transmission connection point) at the time when this summation is greatest. The Maximum Demand does not include Embedded Generation.	Demonstrated in section 3.4.3.3.2 (Approach). Energex does not include Embedded Generation in its calculation of Maximum Demand.
Coincident Weather Adjusted System Annual Maximum	Demonstrated in section 3.4.3.3.2

Requirements (instructions and definitions)	Consistency with requirements
Demand 10% POE is the summation of the Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 10 per cent POE level at the time when this summation is greatest.	(Approach).
Coincident Weather Adjusted System Annual Maximum Demand 50% POE is the summation of the Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 50 per cent POE level at the time when this summation is greatest.	Demonstrated in section 3.4.3.3.2 (Approach).
Maximum Demand is as defined in the NER	*Maximum Demand* is defined in the Rules and applied by Energex as meaning - the highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.
Non–Coincident Raw System Annual Maximum Demand is the actual unadjusted (i.e. not weather normalised) summation of actual raw annual Maximum Demands for the requested asset level (either the zone substation or transmission connection points) irrespective of when they occur within the year. This Maximum Demand is not to be adjusted for Embedded Generation.	Energex has based its calculations of the annual peaks from the data for the summer and winter seasons only (Demonstrated in section 3.4.3.3.2 - Approach). This provides a more accurate representation of customer demand as it excludes anomalies that may occur due to Network configuration changes upstream of the Connection Point. On 22 July 2015 the AER confirmed that this approach was appropriate and acceptable. Energex does not include Embedded Generation in its calculation of Maximum Demand.
Non–Coincident Weather Adjusted System Annual Maximum Demand 10% POE This is the summation of the Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 10 per cent POE level irrespective of when they occur within the year.	Demonstrated in section 3.4.3.3.2 (Approach).
Non–Coincident Weather Adjusted System Annual Maximum Demand 50% POE is the summation of	Demonstrated in section 3.4.3.3.2 (Approach).

Requirements (instructions and definitions)	Consistency with requirements
Weather Adjusted annual Maximum Demands for the requested asset level (either the zone substation or transmission connection point) at the 50 per cent POE level irrespective of when they occur within the year.	
Probability of Exceedance (POE) is the probability that the actual weather circumstances will be such that the actual Maximum Demand experienced will exceed the relevant maximum demand measure adjusted for weather correction.	Demonstrated in section 3.4.3.3.2 (Approach).

3.4.3.2 Sources

- The SIFT database which now incorporates the Probability of Exceedance (POE) tool was used to extract the annual maximum demand across the network at the zone substation and transmission connection point level.
- The Bureau of Meteorology (BOM) was also used to source information on the weather conditions. To calculate the weather adjusted data at the zone substation and Connection Point level the weather data was based on five weather stations (namely Maroochydore, Brisbane Airport, Archerfield, Coolangatta and Amberley).

Table 3.4.16, Table 3.4.17, Table 3.4.18 and Table 3.4.19 detail the sources for additional responses to variables relating to annual system maximum demand:

Table 3.4.16 - Data sources for the annual system maximum demand characteristics at the zone substation level – MW measure

Variable Code	Variable	Source
DOPSD0101	Non-coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0102	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0103	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM
DOPSD0104	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0105	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0106	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM

Table 3.4.17 - Data sources for the annual system maximum demand characteristics at the transmission connection point – MW measure

Variable Code	Variable	Source
DOPSD0107	Non-coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0108	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0109	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM
DOPSD0110	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0111	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0112	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM

Table 3.4.18 - Data sources for the annual system maximum demand characteristics at the zone substation level – MVA measure

Variable Code	Variable	Source
DOPSD0201	Non–coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0202	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0203	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM
DOPSD0204	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0205	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0206	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM

Table 3.4.19 - Data sources for the annual system maximum demand characteristics at the transmission connection point – MVA measure

Variable Code	Variable	Source
DOPSD0207	Non–coincident Summated Raw System Annual Maximum Demand	SIFT
DOPSD0208	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0209	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM
DOPSD0210	Coincident Raw System Annual Maximum Demand	SIFT
DOPSD0211	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	SIFT/BOM
DOPSD0212	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	SIFT/BOM

3.4.3.3 Methodology

3.4.3.3.1 Assumptions

The following assumptions apply to the calculation of 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 from the 01/06 – 30/08;
- The duration of the summer period is from the 01/12 – 5/03;
- Refer to CA RIN BoP 5.4.1 Maximum Demand and Utilisation Spatial section 36.3.1 Assumptions for an explanation of summer and winter peaks.
- The temperature threshold is 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 is 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; and
- The weather data sourced from the Bureau of Meteorology was based on five weather stations, including Maroochydore, Brisbane Airport, Archerfield, Coolangatta and Amberley.

The following assumptions apply to calculation of the weather adjusted data at the transmission connection point level:

- The data is based the summer period from the 01/12 – 5/03.
- The temperature is 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 was below 23.5 degrees Celsius during the summer period was disregarded;
- The temperature data is 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 raw data excluded embedded generation; and
- The weather data sourced from the Bureau of Meteorology was based on the best fit across all 5 weather stations.

3.4.3.3.2 Approach

The weather adjustment process used by Energex was based on the following process:

1) The days that are unlikely to produce a peak demand were excluded.
2) Multiple seasons of data were used and then normalised to remove annual growth. However, at the Connection Point level only one season of data was used – to align with Powerlink/AEMO methodologies.
3) 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 +c)
4) 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 and Connection Point. The adjustments were applied to the raw peak demand to calculate the 10POE and 50POE adjusted demands before aggregation.

The following approach was applied to calculate the annual system maximum demand characteristics at the zone substation level – MW and MVA (RIN tables 3.4.3.1 and 3.4.3.3):

- The demand data for each zone substation was aggregated to find for total non-coincident peak;
- The POE adjustment is based on the standard weather adjustment process using the best fit of five BOM sites and is recorded in SIFT; and
- These adjustments are then applied to the recorded demands and then aggregated to total values in the appropriate row in MW or MVA (as appropriate).

The following approach was applied to calculate the annual system maximum demand characteristics at the transmission connection point – MW and MVA (RIN tables 3.4.3.2 and Table 3.4.3.4):

- The peak demand data for each Zone Substation was aggregated to find for total non- coincident peak;
- The Connection Point coincident MW and MVA values were calculated from system native demand after removal of the adjustment for embedded generation operating at the coincident half hour.
- Energex has not had a consistent methodology of estimating 10POE and 50POE values for peak Connection Point demand history. Energex recently developed a weather adjustment process similar to the AEMO recommended approach for Connection Points.
- Energex uses four coincident half hour time periods: Summer Day, Summer Night, Winter Day and Winter night (SD SN WD WN) - as the equipment ratings vary between season & time of day (the day period is 8am to 5pm). The peak demand in those coincident time periods is matched against the ratings, to measure any ‘load at risk’ and prioritise augmentation works.
- As the coincident peak figure reported can be from any of the four coincident time periods, their aggregated total will be at least as high, and typically higher, than the reconciled total summer system demand – which occurs at one time period.
- The Energex System level POE values will be different from the temperature corrected figures calculated at the individual Connection Point (or Zone Substation level) and aggregated to form a system total number - as the aggregated numbers will naturally smooth out much of the individual variation. The difference is also due to differences in methodology, as the POE methodology used at the Energex System level also incorporates more explanatory variables - like economic and demographic drivers.
- The non-coincident zone substation summated demands any half hour and therefore diversity of load peaks and losses need to be applied to produce equivalent Connection Point peak demands.

3.4.3.4 Estimated Information

No Estimated Information was reported.

3.4.3.4.1 Justification for Estimated Information

Not applicable.

3.4.3.4.2 Basis for Estimated Information

Not applicable.

3.4.3.5 Power factor conversion between MVA and MW

The AER requires Energex to provide the following variables relating to power factor conversion:

3.4.3.5 Power factor conversion between MVA and MW

- **DOPSD0301 - Average overall network power factor conversion between MVA and MW**
- **DOPSD0302 - Average power factor conversion for low voltage distribution lines**
- **DOPSD0303 - Average power factor conversion for 3.3 kV lines**
- **DOPSD0304 - Average power factor conversion for 6.6 kV lines**
- **DOPSD0305 - Average power factor conversion for 7.6 kV lines**
- **DOPSD0306 - Average power factor conversion for 11 kV lines**
- **DOPSD0307 - Average power factor conversion for SWER lines**
- **DOPSD0308 - Average power factor conversion for 22 kV lines**
- **DOPSD0309 – Average power factor conversion for 33 kV lines**
- **DOPSD0310 – Average power factor conversion for 44 kV lines**
- **DOPSD0311 – Average power factor conversion for 66 kV lines**
- **DOPSD0312 – Average power factor conversion for 110 kV lines**
- **DOPSD0313 – Average power factor conversion for 132 kV lines**
- **DOPSD0314 – Average power factor conversion for 220 kV lines**

These variables are part of Regulatory Template 3.4 – Operational Data.

Variable DOPSD0302 - Average power factor conversions for low voltage distribution lines is Estimated Information.

All other information is Actual Information.

3.4.3.5.1 Consistency with EB RIN Requirements

Table 3.4.20 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.4.20 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the power factor to allow for conversion between MVA and MW measures for each voltage.	Demonstrated in section 3.4.3.5.3.2 (Approach).
If both MVA and MW throughput for a network are available then the power factor is the total MW divided by the total MVA. Energex must provide a power factor for each voltage level and for the network as a whole. The average overall power factor conversion (DOPSD0301) is the total MW divided by the total MVA.	Demonstrated in section 3.4.3.5.3.2 (Approach).

Requirements (instructions and definitions)	Consistency with requirements
If either the MW or MVA measure is unavailable the average power factor conversion can be calculated as an approximation based on best engineering estimates.	Demonstrated in section 3.4.3.5.3.2 (Approach).

3.4.3.5.2 Sources

The Substation Investment Forecasting Tool (SIFT) and SCADA databases were used to extract the input data for these variables. This is outlined in Table 3.4.21 below:

Table 3.4.21 –Data Sources

Variable Code	Variable	Unit	Source
DOPSD0301	Average overall network power factor conversion between MVA and MW	Factor	SIFT/SCADA
DOPSD0302	Average power factor conversion for low voltage distribution lines	Factor	SIFT/SCADA
DOPSD0303	Average power factor conversion for 3.3 kV lines	Factor	SIFT/SCADA
DOPSD0304	Average power factor conversion for 6.6 kV lines	Factor	SIFT/SCADA
DOPSD0305	Average power factor conversion for 7.6 kV lines	Factor	SIFT/SCADA
DOPSD0306	Average power factor conversion for 11 kV lines	Factor	SIFT/SCADA
DOPSD0307	Average power factor conversion for SWER lines	Factor	SIFT/SCADA
DOPSD0308	Average power factor conversion for 22 kV lines	Factor	SIFT/SCADA
DOPSD0309	Average power factor conversion for 33 kV lines	Factor	SIFT/SCADA
DOPSD0310	Average power factor conversion for 44 kV lines	Factor	SIFT/SCADA
DOPSD0311	Average power factor conversion for 66 kV lines	Factor	SIFT/SCADA
DOPSD0312	Average power factor conversion for 110 kV lines	Factor	SIFT/SCADA
DOPSD0313	Average power factor conversion for 132 kV lines	Factor	SIFT/SCADA
DOPSD0312	Average power factor conversion for 220 kV lines	Factor	SIFT/SCADA

3.4.3.5.3 Methodology

The methodology and justification for the low voltage distribution line power factor conversion is outlined below in Approach.

3.4.3.5.3.1 Assumptions

No assumptions were made.

3.4.3.5.3.2 Approach

The following approach was applied to calculating the relevant power factor conversion variables:

- Average power factor was calculated using the summated MVA and summated MW at the system level. All data for these calculations was extracted from SCADA;
- Power factor at the132 & 110 kV line level was calculated using the actual MVA and MW at the connection points;
- Power factor at the 33 kV line level was calculated using the actual MVA and MW at the Bulk Supply substations;
- Power factor at the 6.35 kV SWER line level was calculated using the actual MVA and MW at the Somerset Dam Zone Substation;
- Power factor at the 11 kV line level was calculated using the actual MVA and MW at the Zone substations; and
- Power factor at LV line level was estimated using the difference between the average power factor at the bulk supply level and the average power factor at the zone substation level and applying this difference to the Zone substation values. Verification of typical pf at LV was undertaken using 1600 distribution transformers from across the Energex network.

3.4.3.5.4 Estimated Information

Variable DOPSD0302 - Average power factor conversions for low voltage distribution lines is Estimated Information. All other information is Actual Information.

3.4.3.5.4.1 Justification for Estimated Information

Not applicable.

3.4.3.5.4.2 Basis for Estimated Information

Not applicable.

3.4.3.6 Demand Supplied

The AER requires Energex to provide the following variables relating to demand supplied:

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

- **DOPSD0401 - Summated Chargeable Contracted Maximum Demand**
- **DOPSD0402 - Summated Chargeable Measured Maximum Demand**

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

- **DOPSD0403 - Summated Chargeable Contracted Maximum Demand**
- **DOPSD0404 - Summated Chargeable Measured Maximum Demand**

These variables are part of Regulatory Template 3.4 – Operational Data.

All information is Actual Information.

3.4.3.6.1 Consistency with EB RIN Requirements

Table 3.4.22 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER:

Table 3.4.22 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex is only required to complete RIN table 3.4.3.6 if it charges customers for Maximum Demand supplied. If Energex does not charge customers on this basis then Energex should enter ‘0’.	Demonstrated in section 3.4.3.6.3.2 (Approach).
Energex must report Maximum Demand amounts for customers that are charged based upon their Maximum Demand as measured in MW. Where Energex cannot distinguish between contracted and measured Maximum Demand, demand supplied must be allocated to contracted Maximum Demand.	Demonstrated in section 3.4.3.6.3.2 (Approach).
Energex is only required to complete RIN table 3.4.3.7 if it charges customers for demand supplied. If Energex does not charge customers on this basis then Energex must enter ‘0’.	Demonstrated in section 3.4.3.6.3.2 (Approach).
Energex must report Maximum Demand amounts for customers that are charged based upon their Maximum Demand as measured in MVA. Where Energex cannot distinguish between contracted and measured Maximum Demand, demand supplied must be allocated to contracted Maximum Demand.	Demonstrated in section 3.4.3.6.3.2 (Approach).
Maximum Demand is as defined in the NER.	*Maximum Demand* is defined in the Rules and

Requirements (instructions and definitions)	Consistency with requirements
	applied by Energex as meaning - the highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.

3.4.3.6.2 Sources

An internal list of contracted customers, which also includes amounts of demand and dates, in addition to PEACE are the primary data sources used to calculate these variables. This is outlined in the Table 3.4.23 and Table 3.4.24:

Table 3.4.23 - Data source for demand supplied (for customers charged on this basis) – MW measure

Variable Code	Variable	Source
DOPSD0401	Summated Chargeable Contracted Maximum Demand	Contracted Demand Customers August 2015
DOPSD0402	Summated Chargeable Measured Maximum Demand	PEACE

Table 3.4.24 - Data source for demand supplied (for customers charged on this basis) – MVA measure

Variable Code	Variable	Source
DOPSD0403	Summated Chargeable Contracted Maximum Demand	List of Contracted Customers, Amount and Dates
DOPSD0404	Summated Chargeable Measured Maximum Demand	PEACE

3.4.3.6.3 Methodology

3.4.3.6.3.1 Assumptions

No assumptions were applied.

3.4.3.6.3.2 Approach

The following approach was applied to calculate the variables:

- Contracted peak demand was extracted from customer contracts, with each demand being summated in MW, due to the use of kW peak demand tariffs; and

- Annual peak demand measured for those customers was summated to calculate MW and kVA.

Historically, Energex has not had kVA peak contracts due to the standard demand tariff structures. Energex is now contracting new customers in kVA demand.

3.4.3.6.4 Estimated Information

No Estimated Information was used.

3.4.3.6.4.3 Justification for Estimated Information

Not applicable.

3.4.3.6.4.4 Basis for Estimated Information

Not applicable.

3.5 PHYSICAL ASSETS

3.5.1 Circuit Length

The AER requires Energex to provide the following information relating to circuit length:

3.5.1.1 Overhead network length of circuit at each voltage

- **DPA0101 - Overhead low voltage distribution**
- **DPA0102 - Overhead 2.2 kV**
- **DPA0103 - Overhead 6.6kV**
- **DPA0104 - Overhead 7.6 kV**
- **DPA0105 - Overhead 11 kV**
- **DPA0106 - Overhead SWER**
- **DPA0107 - Overhead 22 kV**
- **DPA0108 - Overhead 33kV**
- **DPA0109 - Overhead 44 kV**
- **DPA0110 - Overhead 66 kV**
- **DPA0111 - Overhead 110 kV**
- **DPA0112 - Overhead 132 kV**
- **DPA0113 - Overhead 220 kV**
- **DPA0114 - Other**
- **DPA01 - Total overhead circuit km**

3.5.1.2 Underground network circuit length at each voltage

- **DPA0201 - Underground low voltage distribution**
- **DPA0202 - Underground 5 kV**
- **DPA0203 - Underground 6.6 kV**
- **DPA0204 - Underground 7.6 kV**
- **DPA0205 - Underground 11 kV**
- **DPA0206 - Underground SWER**
- **DPA0207 - Underground 22 kV**
- **DPA0208 - Underground 33 kV**
- **DPA0209 - Underground 66 kV**
- **DPA0210 - Underground 110 kV**
- **DPA0211 - Underground 132 kV**
- **DPA02 - Total underground circuit km**

These variables are part of RIN Table 3.5.1.1 and RIN Table 3.5.1.2 as set out in Regulatory Template 3.5 – Physical Assets.

All information is Actual Information.

3.5.1.1 Consistency with EB RIN Requirements

Table 3.5.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.5.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex is required to report against the capacity variables for the whole network.	Demonstrated in section 3.5.1.3.2 (Approach).
The network includes overhead power lines and towers, underground cables and pilot cables that transfer electricity from the regional bulk supply points supplying areas of consumption to individual zone substations, to distribution substations and to customers.	Demonstrated in section 3.5.1.3.2 (Approach) Energex's figures do not include pilot cables as they are a secondary system, as per the definition below.
The network also includes distribution feeders and the low voltage distribution system but excludes the final connection from the mains to the customer and also wires or cables for public lighting, communication, protection or control and for connection to unmetered loads.	Demonstrated in section 3.5.1.3.2 (Approach).
Specify the voltage for each 'other' voltage level, where applicable.	Energex does not have any other voltage levels to those specified in the AER's RIN Instructions and Definitions.
Circuit length is calculated from the Route length (measured in kilometres) of lines in service (the total length of feeders including all spurs), where each SWER line, single-phase line, and three-phase line counts as one line. A double circuit line counts as two lines. The length does not take into account vertical components such as sag.	Demonstrated in section 3.5.1.3.1 (Assumptions).

3.5.1.2 Sources

The circuit lengths at each voltage level were extracted from the Network Facilities Management (NFM) database. This is outlined in Table 3.5.2 and Table 3.5.3 below:

Table 3.5.2 - Data Source for overhead network length of circuit at each voltage

Variable Code	Variable	Source
DPA0101	Overhead low voltage distribution	NFM
DPA0102	Overhead 2.2 kV	Not Applicable
DPA0103	Overhead 6.6 kV	Not Applicable

Variable Code	Variable	Source
DPA0104	Overhead 7.6 kV	Not Applicable
DPA0105	Overhead 11 kV	NFM
DPA0106	Overhead SWER	NFM
DPA0107	Overhead 22 kV	Not Applicable
DPA0108	Overhead 33 kV	NFM
DPA0109	Overhead 44 kV	Not Applicable
DPA0110	Overhead 66 kV	Not Applicable
DPA0111	Overhead 110 kV	NFM
DPA0112	Overhead 132 kV	NFM
DPA0113	Overhead 220 kV	Not Applicable
DPA0114	Other	Not Applicable
DPA01	Total overhead circuit km	NFM

Table 3.5.3 - Data Source for underground network length of circuit at each voltage

Variable Code	Variable	Source
DPA0201	Underground low voltage distribution	NFM
DPA0202	Underground 5 kV	Not Applicable
DPA0203	Underground 6.6 kV	Not Applicable
DPA0204	Underground 7.6 kV	Not Applicable
DPA0205	Underground 11 kV	NFM
DPA0206	Underground SWER	NFM
DPA0207	Underground 22 kV	Not Applicable
DPA0208	Underground 33 kV	NFM
DPA0209	Underground 66 kV	Not Applicable
DPA0210	Underground 110 kV	NFM
DPA0211	Underground 132 kV	NFM
DPA0212	Other	Not Applicable
DPA02	Total underground circuit km	NFM

The NFM database is the master electronic record of all network assets and their connectivity. NFM is populated from completed field work orders and reflects the "as constructed" state of the network.

Because practical completion is required before capture can occur, there is a delay in the capture of data. Energex currently captures approximately 50% of all records within 20 days of commissioning.

3.5.1.3 Methodology

3.5.1.3.1 Assumptions

The following assumptions and limitations apply to the data:

- Customer owned conductors were generally not captured in the NFM database. However, there were a limited number of instances where:
  - Energex operated the network through these customer assets and therefore required them to be captured; or
  - Selected assets had been sold to customers and the assets may not have been removed from the NFM (this had an immaterial impact on the data).
- Energex limited the impact customer owned conductors would have on reported lengths by assuming that where two customer-owned assets are joined together, the conductor facilitating this connection was also customer-owned. All other instances were unable to be identified and have been included in the overall figure.
- The conductor data does not include conductors that are in store or held for spares.
- The circuit length data only includes those lines that are in service. Conductors that are in the field but de-energised have not been included.
- The length of each conductor category was the total conductor route length and not each individual phase conductor length, noting:
  - 11 kV+ routes predominately consist of 3 conductors.11 kV routes also include single phase (2 conductors) in its total length; and
  - LV routes predominately consist of 4 conductors: 3 phases plus neutral, however lengths provided include all variations.
- All lengths stated exclude any vertical components to the conductor, such as sag and vertical tails.

3.5.1.3.2 Approach

The following approach was applied to calculate the variables:

1) The data for 2014/15 was obtained by running scripts through the NFM database. In particular:

a. The Line_Lengths_By_Year.sql script was run to extract data for each of the voltage levels (11kv including SWER line) for 2014/15. The script extracted data for the overhead and underground circuit length of each voltage level; and

b. A SWER_Line_Lengths_By_Year.sql script was run to extract data for the overhead circuit length of the SWER lines for 2014/15.

2) The SWER length was then deducted from DPA0105 11 kV overhead length and added to DPA0106 Overhead SWER.

The data was validated by checking the results against the Energex Annual Report and Distribution Annual Planning Report (DAPR). In cases where the unexplained variance was greater than 1%, the differences have been investigated and resolved.

3.5.1.4 Estimated Information

No Estimated Information was reported.

3.5.1.4.1 Justification for Estimated Information

Not applicable.

3.5.1.4.2 Basis for Estimated Information

Not applicable.

3.5.1.5 Explanatory Notes

The figures stated for circuit length in RIN tables 3.5.1.1 and 3.5.1.2 may differ from those used in the calculation of circuit capacity in RIN tables 3.5.1.3 and 3.5.1.4. Data for circuit length has been reported previously on an “as constructed” basis and the same methodology has been used in these variables to ensure consistency. The circuit length used for the calculation of circuit capacities in RIN tables 3.5.1.3 and 3.5.1.4 is on an “as operated basis”.

3.5.2 Circuit Capacity LV - MVA

The AER requires Energex to provide the following information in relation to circuit capacity for low voltage distribution:

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

- **DPA0301 – Overhead low voltage distribution**
- **DPA0302 – Overhead 6.6 kV**
- **DPA0303 – Overhead 7.6 kV**
- **DPA0304 – Overhead 11 kV**
- **DPA0305 – Overhead SWER**
- **DPA0306 – Overhead 22 kV**
- **DPA0307 – Overhead 33 kV**
- **DPA0308 – Overhead 44 kV**
- **DPA0309 – Overhead 66 kV**
- **DPA0310 – Overhead 110 kV**
- **DPA0311 – Overhead 132 kV**
- **DPA0312 – Overhead 220 kV**
- **DPA0313 Other**

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

- **DPA0401 – Underground low voltage distribution**
- **DPA0402 – Underground 5 kV**
- **DPA0403 – Underground 6.6 kV**
- **DPA0404 – Underground 7.6 kV**
- **DPA0405 – Underground 11kV**
- **DPA0406 – Underground SWER**
- **DPA0407 – Underground 12.7 kV**
- **DPA0408 – Underground 22 kV**
- **DPA0409 – Underground 33 kV**
- **DPA0410 – Underground 66 kV**
- **DPA0411 – Underground 110 kV**
- **DPA0412 – Underground 132 kV**
- **DPA0413 – Other**

These variables are part of RIN Table 3.5.1.3 and RIN Table 3.5.1.4 as set out in Regulatory Template 3.5 – Physical Assets.

All information Estimated Information.

3.5.2.1 Consistency with EB RIN Requirements

Table 3.5.4 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER:

Table 3.5.4 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances must be provided taking account of limits imposed by thermal or by voltage drop considerations as relevant.	Demonstrated in section 3.5.2.3.2 (Approach).
The summer Maximum Demands are to be provided for summer peaking assets and the winter Maximum Demands are to be provided for winter peaking assets.	As this requirement is inconsistent with the remaining AER Instructions and Definitions and with the Data Template itself it has not been addressed in the methodology. That is, this refers to Maximum Demand when the remainder of the report relate to capacity.
Where the peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there was a winter peak and summer ratings for those years where there was a summer peak.	Demonstrated in section 3.5.2.3.1 (Assumptions).
Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, Energex may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	Demonstrated in section 3.5.2.3.2 (Approach).

3.5.2.2 Sources

The data sources used to estimate the relevant variables are set out in Table 3.5.5:

Table 3.5.5 – Data Sources

Variable Code	Variable	Source
DPA0301	Overhead low voltage distribution	NFM/2008 Plant Rating Manual/Conductor Catalogue
DPA0401	Underground low voltage distribution	NFM/2008 Plant Rating Manual/Conductor Catalogue

3.5.2.3 Methodology

3.5.2.3.1 Assumptions

In relation to the LV circuit line lengths used to calculate the weighted average circuit ratings, the following assumptions were made:

- Customer owned conductors were generally not captured in the NFM database. However, there were a limited number of instances where:
  - Energex operated the network through these customer assets and therefore required them to be captured; or
  - Selected assets had been sold to customers and the assets may not have been removed from the NFM (which had an immaterial impact on the data.)

In these few instances Energex was unable to exclude the conductors;

- The conductor data does not include conductors that are in store or held for spares;
- The length of each conductor category was the total conductor route length and not each individual phase conductor length. In particular, LV routes predominately consist of 4 conductors (namely 3 phases plus neutral). However, it should also be noted that lengths provided include all variations;
- All lengths stated exclude any vertical components to the conductor, such as sag and vertical tails; and
- As a single line diagram was used, where multiple conductors were present within the single line the conductor with the highest count was chosen. Where multiple different conductors were found with the same count then the last installed conductor was chosen.

These assumptions are the same as those used to prepare the LV circuit line lengths for DPA0101 and DPA0201 variables in RIN tables 3.5.1.1 and 3.5.1.2.

In addition, the following assumptions and limitations also underpin the calculation of these variables:

- Energex's LV asset level has a thermal summer voltage limiting rating (as set out in the AER's RIN Instructions and Definitions);
- Where an individual conductor was not included in the Energex Plant Rating Manual or Conductor Catalogues, the rating associated with the nearest listed conductor was used for that conductor. The impact of this assumption was immaterial on the overall data, as there was a small number of instances where this occurred and it did not relate to current standard conductors;
- Overhead (aerial) metric conductors are assumed to be strung to a conductor temperature design of 75 degrees. Conductor stringing to 75 degrees was introduced around the 1980's and is closely aligned to the introduction of metric

conductors. Prior to the metric conductors, imperial conductors were used and strung to a more conservative conductor temperature of 55 degrees;

- The underground conductors were assigned a thermal summer day (inducts) rating from the Plant Rating Manual;
- A single average thermal de-rating factor for overhead conductors and a single average thermal de-rating factor for underground conductors to account for contingency loading and voltage limitations were derived from the experience of Energex planning and design staff; and
- The average thermal de-rating factors are applied globally to the conductors in the overhead and underground categories rather than identify individual LV circuits and their individual limiting conductors. Values are therefore based on estimated data.

3.5.2.3.2 Approach

The following approach was applied to calculating the variables:

1) Low voltage (LV) circuit line lengths were obtained by conductor description for overhead and underground for Regulatory Year ending 30 June 2015 (this data is covered in the Basis of Preparation for circuit lengths). The circuit line length and conductor data was cross checked for consistency with the total lengths data for overhead and underground conductors provided in the RIN;

2) A conductor rating table was created by:
    a. Assigning a thermal rating to the unique list of conductor types/sizes installed on the network (based on its description) using the Energex Plant Rating Manual or Conductor Catalogues (if necessary);
    b. For all overhead conductors types/sizes listed in the Plant Rating Manual, the summer day thermal ratings for Category A sub-circuits for 55 degrees and 75 degrees conductor temperature stringing were extracted;
    c. All overhead conductors types/sizes installed on the network were classified with ratings extracted from the Plant Rating Manual as either "imperial" or "metric" conductor;
    d. A 55 degree rating was assigned to overhead conductors with an "imperial" type/size and a 75 degree rating was assigned to overhead conductors with a "metric" type/size; and
    e. For overhead conductors installed on the network not listed in the Plant Rating Manual, a summer day thermal rating with reference to the Olex Aerial Catalogue March 1999 and Nexan's Handbook 2003 Edition was assigned for the nearest stringing conductor temperature of 75 degrees;

3) The overhead and underground average thermal de-rating factors were determined. This involved estimating the thermal de-rating factors for LV overhead and underground designed networks to account for contingency load and voltage limitations;

4) The average thermal de-rating factors for conductors were applied. This involved:

   a. Assigning the overhead and underground average thermal estimated de-rating factors to the thermal rating of each conductor type (0.8 for UG and 0.7 for OH) to determine the voltage limited rating of each conductor; and

   b. Summating the voltage limited conductor rating multiplied by the length of conductor (amps multiplied by kms) for overhead and underground categories;

5) The weighted average voltage limited circuit rating (Amps) for overhead and underground was obtained by using the following formulas:

$$underground\ Rating\ MVA =$$

$$\frac{\sum^{UG\ conductor\ types} Conductor\ type\ rating\ \times conductor\ type\ length}{System\ Total\ UG\ circuit\ length}$$

$$overhead\ Rating\ MVA =$$

$$\frac{\sum^{OH\ conductor\ types} Conductor\ type\ rating\ \times conductor\ type\ length}{System\ Total\ OH\ circuit\ length}$$

6) The weighted average voltage limited circuit rating in Amps was converted to MVA by multiplying by sqrt(3) x 415V and dividing by 1,000,000.

3.5.2.4 Estimated Information

All information is Estimated Information.

3.5.2.4.1 Justification for Estimated Information

Average thermal de-rating factors for overhead and underground network to account for contingency loading and voltage drop limitations do not exist as part of the normal planning and design process. Energex has a planning and supply manual which dictates all the relevant design parameters, including allowable voltage drop. As a result, these factors were developed solely to account for voltage limitations for this purpose and reflect Estimated Information.

3.5.2.4.2 Basis for Estimated Information

Energex's approach recognises that LV network are typically voltage constrained rather than thermally constrained. Taking the thermal ratings without any account of voltage limitations would result in an overstatement of the circuit rating values for overhead and underground networks. As a result, Energex applied average de-rating factors for contingency loading and voltage limitations based on the experience of Energex planning and design staff. The ratings so derived are lower than the thermal ratings by the value of the de-rating factors.

3.5.2.5 Explanatory Notes

The RIN includes a requirement to report information in RIN tables 3.5.1.3 and 3.5.1.4 as Actual Information from the 2015 regulatory year. On 6 July 2015, the AER advised that information in these tables is not required to be reported as Actual Information as the average values are inherently estimated.

3.5.3 Circuit Capacity – 11kV and SWER

The AER requires Energex to provide the following information relating to circuit capacity for 11kV and SWER:

Estimated overhead network weighted average MVA capacity by voltage class

- **DPA0304 - Overhead 11 kV**
- **DPA0305 - Overhead SWER**

Estimated underground network weighted average MVA capacity by voltage class

- **DPA0405 - Underground 11 kV**

These variables are part of RIN Table 3.5.1.3 and RIN Table 3.5.1.4 as set out in Regulatory Template 3.5 – Physical Assets.

All information is Estimated Information.

3.5.3.1 Consistency with EB RIN Requirements

Table 3.5.6 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.5.6 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances must be provided taking account of limits imposed by thermal or by voltage drop considerations as relevant.	Demonstrated in section 3.5.3.3.2 (Approach).
The summer Maximum Demands are to be provided for summer peaking assets and the winter Maximum Demands are to be provided for winter peaking assets.	There is some variation in the terminology used in the Instructions and Definitions document. Both Maximum Demand and Capacity has been referred to. For the basis of this analysis it has been inferred that the requirement is for capacity figures.
Where the peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there was a winter peak and summer ratings for those years where there was a summer peak.	Demonstrated in section 3.5.3.3.1 (Assumptions).

Requirements (instructions and definitions)	Consistency with requirements
Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, Energex may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	Demonstrated in section 3.5.3.3.2 (Approach).

3.5.3.2 Sources

The primary information sources used to extract the necessary data to calculate the circuit capacities for 11 kV was DINIS (Distribution Network Information System) and for SWER the NFM database. This is outlined in Table 3.5.7 and Table 3.5.8:

Table 3.5.7 – Data source for estimated overhead network weighted average MVA capacity by voltage class

Variable Code	Variable	Source
DPA0304	Overhead 11 kV	DINIS
DPA0305	Overhead SWER	NFM

Table 3.5.8 – Data source for estimated underground network weighted average MVA capacity by voltage class

Variable Code	Variable	Source
DPA0405	Underground 11 kV	DINIS

Energex also used the Plant Rating Manual and the ERAT corporate ratings tool to validate the datasets and to develop estimation methods.

3.5.3.3 Methodology

3.5.3.3.1 Assumptions

The following assumptions underpin the calculation of these figures:

- 'Energex's peak' (as set out in the AER's Instructions and Definitions) was interpreted as being the system peak season, rather than the peak associated with individual assets. Therefore network capacities have been calculated based on summer day loads and ratings; and

- The circuit constraint was identified by assuming any increase in load was applied in proportion to the DINIS load flow allocated load.

3.5.3.3.2 Approach

The following approach was applied to calculating the variables:

- The DINIS length data was compared to the length data obtained from NFM. Discrepancies were investigated to ensure validity of both source data sets where possible;
- The DINIS constrained feeder capacity was cross-checked against the ERAT corporate operational ratings tool;
- Each cable segment was categorised as overhead or underground;

Different approaches were applied for feeder capacity and are set out below:

- For 11 kV conductors, the constrained rating (capacity) of a feeder was determined by finding the highest thermal utilisation of each cable segment in the feeder or the highest voltage drop on the feeder. These values were scaled until the thermal or voltage limited segment reached 100% capacity or would exceed the voltage drop threshold. The capacity of all conductor segments in that circuit were then calculated at the loading where no thermal or voltage limitations were exceeded along the circuit;
- For the SWER conductors, capacity was taken as the rating of the SWER isolation transformer as this was the limiting factor for the capacity of the SWER feeders. The nameplate rating of these transformers was used to represent the constraint rating for these feeders;
- For 11 kV, each segment length was then multiplied by the segment demand at the feeder's thermal or voltage limited capacity;
- For SWER, the length of conductor off each isolation transformer was multiplied by the capacity;
- The total was then divided by the total feeder UG/OH length section to obtain the weighted average MVA; and
- The formula below was applied:

$$\text{UG weighted average MVA} = \frac{\sum_{N}\left(MVA_N \times UG\_SegmentLength_N\right)}{Total\_UG\_SegmentLength}$$

$$\text{OH weighted average MVA} = \frac{\sum_{N} \left(MVA_N \times OH\_SegmentLength_N \right)}{Total\_OH\_SegmentLength}$$

Where:

- MVAN is the capacity of the segment at the constrained rating of the segment in the feeder
- UG_SegmentLengthN is the total UG length (km) of segment
- OH_SegmentLengthN is the total OH length (km) of segment
- Total_UG_SegmentLength is the total UG feeder length in the Energex network
- Total_OH_SegmentLength is the total OH feeder length in the Energex network

3.5.3.4 Estimated Information

All information is Estimated Information.

3.5.3.4.1 Justification for Estimated Information

For the 11 kV capacities, the DINIS network model and ERAT database only provide the current state of the network. No historical values are available for the DINIS network model, as this has never been required. However, ERAT circuit ratings are published annually in the Distribution Annual Planning Report (DAPR) and historically in the Network Management Plan (NMP). The ERAT rating is based on the feeder backbone conductors, and this is used to provide operational ratings. Furthermore, these ratings are not separated into overhead or underground components.

3.5.3.4.2 Basis for Estimated Information

For the 2014/15 year capacities, load flow analysis was undertaken to identify the capacity limitation for each feeder by determining the thermal or voltage limit. This has been used to determine the weighted average capacity for the network in 2014/15.

3.5.3.5 Explanatory Notes

Rating Conversion

Energex line ratings are expressed in current capacity (A), the conversion from A to MVA was done assuming nominal voltage of 11 kV.

$$\text{Rating (A) x 11000 (V) x } \sqrt{3} \text{ / 1000000 = Rating (MVA)}$$

3.5.4 Circuit Capacity – 33 kV

The AER requires Energex to provide the following information relating to circuit capacity for 33kV:

Estimated overhead network weighted average MVA capacity by voltage class

- **DPA0307 - Overhead 33 kV**

Estimated underground network weighted average MVA capacity by voltage class

- **DPA0409 - Underground 33 kV**

These values are part of RIN Table 3.5.1.3 and RIN Table 3.5.1.4 as set out in Regulatory Template 3.5 – Physical Assets.

All information is Estimated Information.

3.5.4.1 Consistency with EB RIN Requirements

Table 3.5.9 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.5.9 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances must be provided taking account of limits imposed by thermal or by voltage drop considerations as relevant.	Demonstrated in 3.5.4.3.2 (Approach)
The summer Maximum Demands are to be provided for summer peaking assets and the winter Maximum Demands are to be provided for winter peaking assets.	As this requirement is inconsistent with the remaining AER Instructions and Definitions and with the Data Template itself it has not been addressed in the methodology. That is, this refers to Maximum Demand when the remainder of the report relate to capacity.
Where Energex's peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years where there is a winter peak and summer ratings for those years where there is a summer peak.	Demonstrated in 3.5.4.3.1 (Assumptions)
Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, Energex may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	Demonstrated in 3.5.4.3.2 (Approach)

3.5.4.2 Sources

As outlined in Table 3.5.10 below, data was extracted from a number of primary data sources:

Table 3.5.10 – Primary Data Sources

Variable Code	Variable	Source
DPA0307	Overhead 33 kV	Sincal, GIS/NFM, ERAT2
DPA0409	Underground 33 kV	Sincal, GIS/NFM, ERAT2

Energex also used the following secondary data sources to validate figures:

- ‘SIFT or Mailbot – to investigate the commissioning date of feeders

3.5.4.3 Methodology

3.5.4.3.1 Assumptions

The following criteria underpin the calculation of these values:

- ‘Energex’s peak’ (as set out in the AER’s Instructions and Definitions) is deemed to be the system peak;
- All values are based on energised operating voltage.

3.5.4.3.2 Approach

The following approach is applied to calculating the values:

1) The feeder conductor types and lengths are obtained from GIS and/or ‘As-constructed’ drawings.

2) The feeder rating data on the limiting section is obtained from the ERAT2. The circuit breaker rating data is obtained from NFM.

3) The 33kV network is modelled in Sincal. Load flow study using the 2015 summer day forecast was conducted to identify the highest utilised segment of the feeders. The rating of the highest utilised feeder segment is then compared with the circuit breaker rating. The lower rating is used to represent the overall constrained rating of the feeder.

4) Line rating and length data is extracted from the Sincal.

5) To obtain the weighted average MVA, the length of each feeder is divided into its respective UG and OH length components, which is recorded in the Sincal.

6) Each feeder UG/OH length component is then multiplied by the feeder rating for the most constrained feeder section and then aggregated.

7) The total is then divided by the total feeder UG/OH length sections to obtain the weighted average MVA. The formula below is applied:

$$\text{UG weighted average MVA} = \frac{\sum_{N} \left(MVA_N \times UG\_Length_N \right)}{Total\_UG\_Length}$$

$$\text{OH weighted average MVA} = \frac{\sum_{N} \left(MVA_N \times OH\_Length_N \right)}{Total\_OH\_Length}$$

Where:

- MVA is the constrained feeder rating of feeder N
- UG_Length is the total length of UG component of feeder N (km)
- OH_Length is the total length of OH component of feeder N (km)
- Total_UG_Length is the aggregated UG feeder length of all 33kV energised circuits in the Energex network (km)
- Total_OH_Length is the aggregated OH feeder length of all 33kV energised circuits in the Energex network (km)

3.5.4.4 Estimated Information

Values provided for the 33kV voltage class are Estimated Information as per AER instructions.

3.5.4.4.1 Justification for Estimated Information

The values provided are based on available data as there is a lag between project commissioning and when some data is uploaded onto GIS. Where actual data is unavailable, estimated values are presented based on design information.

3.5.4.4.2 Basis for Estimated Information

The data is populated based on Energex's Sincal network simulation model, the Sincal model contains engineering data on existing and proposed network, and is maintained using data from project scope statements and updated as project scopes are refined or when as-constructed drawings becomes available. The Sincal model is used for network analysis across Energex and is an accurate representation of the network, verified with source data held in the GIS.

3.5.4.5 Explanatory Notes

Rating Conversion

Energex line ratings are expressed in current capacity (A), the conversion from A to MVA is done assuming nominal voltage of 33 kV.

$$\text{Rating (A)} \times 33000\ \text{(V)} \times \sqrt{3}\ /\ 1000000 = \text{Rating (MVA)}$$

UG/OH lengths

There are a number of underground and overhead lengths that aren't included in the calculations of these values. This means that the lengths reported in RIN Tables 3.5.1.1 and 3.5.1.2 are different (and higher in value). Criteria for lengths include the following:

- Reported line lengths in RIN Tables 3.5.1.1 and 3.5.1.2 of the AER EB RIN data template are based on construction voltage rather than energised voltage, as identified in the table above. The rating is calculated based on energised voltage. (For example, feeder IPS3A is constructed at 33 kV but energised at 11 kV. Length data include this 33 kV construction, however, it should be 11 kV based on energised voltage.)

- Project timing is verified for purposes of rating data and line length values. Project completion dates are verified against corporate systems, such as Mailbot or SIFT, and this data is adjusted to match the actual project timing or commissioning date.

- The GIS does not have up-to-date information. The GIS line length extract reported a number of feeders with names ending with "OLD", some of these feeders might be decommissioned and no longer supplying load.

- No feeder names being allocated to the feeder length data. (For example, UNNAMED558.)

3.5.5 Circuit Capacity – 110 kV and 132 kV

The AER requires Energex to provide the following values relating to circuit capacity for 110/132kV:

Overhead network weighted average MVA capacity by voltage class

- **DPA0306 Overhead 22 kV**
- **DPA0308 Overhead 44 kV**
- **DPA0309 Overhead 66 kV**
- **DPA0310 Overhead 110 kV**
- **DPA0311 Overhead 132 kV**
- **DPA0312 Overhead 220 kV**

Underground network weighted average MVA capacity by voltage class

- **DPA0408 Underground 22 kV**
- **DPA0410 Underground 66 kV**
- **DPA0411 Underground 110 kV**
- **DPA0412 Underground 132 kV**

Values are part of RIN Table 3.5.1.3 and RIN Table 3.5.1.4 as set out in Regulatory Template 3.5 – Physical Assets.

All information is Estimated Information.

3.5.5.1 Consistency with EB RIN Requirements

Table 3.5.11 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.5.11 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
The estimated typical or weighted average capacities for each of the listed voltage classes under normal circumstances must be provided taking account of limits imposed by thermal or by voltage drop considerations as relevant.	Demonstrated in 3.5.5.3.2 (Approach)
The summer Maximum Demands are to be provided for summer peaking assets and the winter Maximum Demands are to be provided for winter peaking assets.	As this requirement is inconsistent with the remaining AER Instructions and Definitions and with the Data Template itself it has not been addressed in the methodology. That is, this refers to Maximum Demand when the remainder of the report relate to capacity.
Where Energex's peak has changed from winter to summer (or vice versa) over the time period, winter ratings should be applied for those years	Demonstrated in 3.5.5.3.2 (Approach)

Requirements (instructions and definitions)	Consistency with requirements
where there is a winter peak and summer ratings for those years where there is a summer peak.	
Where circuits travel both overhead and underground and the capacity of the overhead and underground components is not available separately, Energex may split the circuit capacity by the ratio of the network that is overhead and underground to form estimates of the overhead capacity and underground capacity components.	Demonstrated in 3.5.5.3.2 (Approach)

3.5.5.2 Sources

A number of primary data sources are used to derive the total installed capacity for each of the overhead and underground feeders. This is outlined in Table 3.5.12 below:

Table 3.5.12 – Primary Data Sources

Variable Code	Variable	Source/s
DPA0310	Overhead 110 kV	PSS/E, ERAT 2, NFM/GIS, Project Approval Report
DPA0311	Overhead 132 kV	PSS/E, ERAT 2, NFM/GIS, Project Approval Report
DPA0411	Underground 110 kV	PSS/E, ERAT 2, NFM/GIS, Project Approval Report

Energex also used the following data sources to validate values:

- SIFT
- Mailbot

3.5.5.3 Methodology

3.5.5.3.1 Assumptions

The following criteria underpin the calculation of these values:

- 'Energex's peak' (as set out in the AER's Instructions and Definitions) is deemed to be Energex system peak;
- All of the results are based on the energised operating voltage.

3.5.5.3.2 Approach

The following approach is applied to calculating the values:

1) The feeder rating data for 14/15 is obtained from ERAT2. If the feeders are identified to be thermally limited by its circuit breaker, the circuit breaker rating is then used to represent the rating of the feeder.

2) The current template requires Energex to segregate the 110kV and 132kV feeders as a separate category. This separation is done based on the allocated voltage level for each feeder as per ERAT2 and is verified through the Energex PSS/E models and DMS systems.

3) The rating of a feeder is dictated by the utilisation of the feeder section. The highest utilisation of a feeder section is used to represent the overall constrained rating of that feeder.

4) Line length data is extracted from Energex GIS system and is matched to each feeder name and rating.

5) To obtain the weighted average MVA, each feeder is divided into its respective voltage levels and to its UG and OH length components.

6) Each feeder length component is then multiplied by the feeder rating for the most constrained feeder section, and then aggregated.

7) The total is then divided by the total feeder UG/OH section length to obtain the weighted average MVA. The formula below is applied:

$$\text{UG weighted average MVA} = \frac{\sum_{N}\left(MVA_N \times UG\_Length_N\right)}{Total\_UG\_Length}$$

$$\text{OH weighted average MVA} = \frac{\sum_{N}\left(MVA_N \times OH\_Length_N\right)}{Total\_OH\_Length}$$

Where:

- MVA is the constrained feeder rating of feeder Fn
- UG_Length is the total UG length (km) of feeder Fn
- OH_Length is the total OH length (km) of feeder Fn
- Total_UG_Length is the total UG feeder length in the Energex network
- Total_OH_Length is the total OH feeder length in the Energex network

3.5.5.4 Estimated Information

All information is Estimated Information.

3.5.5.4.1 Justification for Estimated Information

Not applicable.

3.5.5.4.2 Basis for Estimated Information

Not applicable.

3.5.5.5 Explanatory Notes

The Energex network does not comprise 22 kV, 44 kV, 66 kV or 220kV voltage classes, therefore the values provided for these have been left blank.

Energex line ratings are expressed in current capacity (A), the conversion from A to MVA is done assuming nominal voltage of 110 kV and 132 kV.

$$\text{Rating (A)} \times 110000\ \text{(V)} \times \sqrt{3} / 1000000 = \text{Rating (MVA)}$$

$$\text{Rating (A)} \times 132000\ \text{(V)} \times \sqrt{3} / 1000000 = \text{Rating (MVA)}$$

It should be noted that not all of the circuit length data reported in RIN Tables 3.5.1.1 and 3.5.1.2 of the AER EB RIN data template is used to calculate the weighted average capacities for the110 kV and132 kV feeders due to the following reasons:

- Decommissioned routes, civil works and any segment which has a valid circuit prior to the specified date is not extracted. This is due to the fact that these feeders do not have a null Feeder/Circuit outside the specified date; and
- Circuit construction voltage is used when extracting the length data. In the DAPR, EB RIN, DAPR and Annual Report, the constructed voltage (segment voltage) is used, not the energised voltage.

Unaccounted UG/OH lengths

There are a number of underground and overhead lengths that are not included in the calculations of these values. This means that the lengths reported in RIN Tables 3.5.1.1 and 3.5.2.1 are different. These unaccounted lengths due to:

- Undefined feeder segments due to mitigating circumstances allocated to the feeder length data. (For example, FMDRTR6H or T31TR4H)
- Feeders that are 110 kV but are operating at the 33 kV voltage level. (For example, feeders to FBS are 110 kV constructed but energised at 33 kV. Length data consider this 110 kV, however here it is considered 33 kV based on operating voltage. Calculations are based on operating voltage.)

The difference in lengths and their effect on the values is immaterial.

3.5.6 Distribution transformer total installed capacity

The AER requires Energex to provide the following variables relating to distribution transformer total installed capacity:

- **DPA0501 - Distribution Transformer Capacity owned by utility**
- **DPA0502 - Distribution Transformer Capacity owned by High Voltage Customers**
- **DPA0503 - Cold Spare Capacity included in DPA0501**

These variables are part of RIN Table 3.5.2.1 as set out in Regulatory Template 3.5 – Physical Assets.

All information is Actual Information.

3.5.6.1 Consistency with EB RIN Requirements

Table 3.5.13 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.5.13 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report total installed Distribution Transformer Capacity.	Demonstrated in section 3.5.6.3.2 (Approach)
The total installed Distribution Transformer Capacity is the transformer capacity involved in the final level of transformation, stepping down the voltage used in the distribution lines to the level used by the customer. It does not include intermediate transformation capacity (e.g. 132 kV or 66 kV to the 22 kV or 11 kV distribution level).	Demonstrated in section 3.5.6.3.2 (Approach)
The capacity measure is the normal nameplate continuous capacity / rating (including forced cooling and other factors used to improve capacity).	Demonstrated in section 3.5.6.3.2 (Approach)
The measure includes Cold Spare Capacity of Distribution Transformers and excludes the capacity of all zone substation transformers, voltage transformers (potential transformers) and current transformers.	Demonstrated in section 3.5.6.3.2 (Approach)
The transformer capacity owned by Energex is to be reported using the nameplate continuous rating including forced cooling.	Demonstrated in section 3.5.6.3.2 (Approach) The data does not include forced cooling as it is not applicable for Energex.

Requirements (instructions and definitions)	Consistency with requirements
The transformation capacity from high voltage to customer utilisation voltage that is owned by customers connected at high voltage is to be provided.	Demonstrated in section 3.5.6.3.2 (Approach)
Where the transformer capacity owned by customers connected at high voltage is not available, the summation of individual Maximum Demands of high voltage customers whenever they occur is required to be provided (i.e. the summation of single annual Maximum Demand for each customer) as a proxy for delivery capacity within the high voltage customers.	Demonstrated in section 3.5.6.3.2 (Approach)
Energex must report the total capacity of spare transformers owned by Energex but not currently in use.	Demonstrated in section 3.5.6.3.2 (Approach)
A Distribution Transformer is a transformer that provides the final voltage transformation in the electricity distribution system, stepping down the voltage used in the distribution lines to the level used by the customer.	Demonstrated in section 3.5.6.3.2 (Approach)
The Cold Spare Capacity is the capacity of spare transformers owned by Energex but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and / or making of connections would require manual intervention at the site of use.	Demonstrated in section 3.5.6.3.2 (Approach).

3.5.6.2 Sources

The input data for the distribution transformer total installed capacity variables were extracted from the NFM database, PEACE and Ellipse. This is outlined Table 3.5.14 below.

Table 3.5.14 – Data Sources

Variable Code	Variable	Source
DPA0501	Distribution Transformer Capacity owned by utility	NFM/Ellipse
DPA0502	Distribution Transformer Capacity owned by High Voltage Customers	PEACE
DPA0503	Cold Spare Capacity included in DPA0501	Ellipse

- The NFM database is the master electronic record of distribution transformer installed capacity and their connectivity. It is populated from completed field work orders and reflects "as constructed" state of the network.

- PEACE is Energex's billing system and was used to source the input data used to calculate the distribution transformer capacity owned by high voltage customers.

- Ellipse is an Enterprise Resource Planning system used by Energex to manage internal and external resources including assets, financial resources, materials, and human resources. It is grouped into sub-systems providing:
  - Maintenance and repair scheduling;
  - Workforce management, resource allocation, skills, training and payroll;
  - Materials management and resource management; and
  - Financial management.

3.5.6.3 Methodology

3.5.6.3.1 Assumptions

The following assumptions and limitations apply to "Distribution transformer capacity owned by utility" (DPA0501):

- Total installed transformer capacity (MVA) was reported using the recorded nameplate rating from NFM;

- Only the normal state of the network was taken into account;

- Only transformers recorded in NFM as connected to the network and with a nameplate rating at the time specified were included in the data;

- Non-Energex owned assets were excluded from the data; and

- The capacity data includes assets that are in store or held for spares.

The following assumptions and limitations apply to Distribution Transformer Capacity owned by High Voltage Customers (DPA0502):

- The value is estimated based on the peak demand recorded by the customer for the 2014/15 period.

The following assumptions and limitations apply to Cold Spare Capacity included in DPA0501 (DPA0503):

- The number and mix of assets held in stores varies each day. Stock levels are as of the 30th of June 2015;

- Actual Information was available for 2014/15.

- Energex does not have any transformer assets that could be described as cold capacity as per the AER definitions; and
- The capacity includes strategic spares as well as normal stock holding owned by Energex.

3.5.6.3.2 Approach

The following approach was applied to calculating the distribution transformer capacity owned by utility (DPA0501):

- The data was obtained by running the Capacity_DTx_By_Year.sql. script through the NFM database for 2014/15 period;
- The data was then combined into a master document and arranged into the AER template format; and
- Cold spare capacity was added to the distribution transformer installed capacity to give total distribution transformer capacity owned by Energex.

The following approach was applied to calculating Distribution Transformer Capacity owned by High Voltage Customers (DPA0502):

- As the transformer capacity owned by customers at high voltage was largely not available, the calculation was based on the recorded annual peak demand; and
- Where capacities were available these values were used.

The following approach was applied to calculating the Cold spare capacity included in DPA0501 (DPA0503):

- The data was obtained through the INV004 – Stock on Hand by Warehouse and Item EPM report, this report is generated from a database containing daily snapshots of inventory held in Ellipse;
- Distribution transformer assets were extracted from the report as at the 30th of June 2015;
- Distribution transformer capacity was extracted from the stock code description

3.5.6.4 Estimated Information

No Estimated Information was reported.

3.5.6.4.1 Justification for Estimated Information

Not applicable.

3.5.6.4.2 Basis for Estimated Information

Not applicable.

3.5.7 Zone Substations Transformer Capacity

The AER requires Energex to provide the following information relating to zone substation transformer capacity:

- **DPA0601 - Total installed capacity for first step transformation where there are two steps to reach distribution voltage**
- **DPA0602 - Total installed capacity for second step transformation where there are two steps to reach distribution voltage**
- **DPA0603 - Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage**
- **DPA0604 - Total zone substation transformer capacity**
- **DPA0605 - Cold spare capacity of zone substation transformers included in DPA0604**

These variables are part of RIN Table 3.5.2.2 as set out in Regulatory Template 3.5 – Physical Assets.

All information is Actual Information.

3.5.7.1 Consistency with EB RIN Requirements

Table 3.5.15 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.5.15 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the transformer capacity used for intermediate level transformation capacity in either one or two steps.(For example, high voltages such as 132 kV, 66 kV or 33 kV at the zone substation level to the distribution level of 22 kV, 11 kV or 6 kV.)	Demonstrated in section 3.5.7.3.2 (Approach).
These measures are required to be the summation of normal assigned continuous capacity / rating (with forced cooling or other capacity improving factors included) and include both energised transformers and Cold Spare Capacity.	Demonstrated in section 3.5.7.3.2 (Approach).
Where available, the assigned rating must be determined from results of temperature rise calculations from testing. Otherwise the nameplate rating is to be provided. For those zone substations where the thermal capacity of exit feeders is a constraint, thermal capacity of exit feeders should be reported instead of transformer capacity.	Demonstrated in section 3.5.7.3.2 (Approach).
The total installed capacity for first step transformation where there are two steps to reach distribution voltage (DPA0601) includes, for example, 66 kV or 33 kV to 22 kV or	Demonstrated in section 3.5.7.3.2 (Approach)

Requirements (instructions and definitions)	Consistency with requirements
11 kV where there will be a second step transformation before reaching the distribution voltage. This variable is only relevant where Energex has more than one step of transformation, if this is not the case Energex must enter ‘0’ for this variable.	
The total installed capacity for second step transformation is required to be reported where there are two steps to reach distribution voltage (DPA0602). (e.g. 66 kV or 33 kV to 22 kV or 11 kV where there has already been a step of transformation above this at higher voltages within Energex’s system.) This variable is only relevant where Energex has more than one step of transformation, if this is not the case Energex must enter ‘0’ for this variable.	Demonstrated in section 3.5.7.3.2 (Approach)
The total zone substation transformer capacity where there is only a single transformation to reach distribution voltage is to be reported (DPA0603). This variable is only relevant where there is only a single step of transformation to reach distribution voltage. If there is more than one step of transformation to reach distribution voltage, the relevant capacities must be reported in DPA0601 and DPA0602.	Demonstrated in section 3.5.7.3.2 (Approach)
The total zone substation transformer capacity (DPA0604) is the overall total zone substation capacity regardless of whether one or two steps are used to reach the distribution voltage (for example DPA0604 will be the sum of DPA0601, DPA0602, DPA0603 and DPA0605.)	Demonstrated in section 3.5.7.3.2 (Approach)
The total Cold Spare Capacity included in total zone substation transformer capacity is to be provided.	Demonstrated in section 3.5.7.3.2 (Approach)
A Distribution Transformer is a transformer that provides the final voltage transformation in the electricity distribution system, stepping down the voltage used in the distribution lines to the level used by the customer.	Demonstrated in section 3.5.7.3.2 (Approach)
Cold spare capacity is the capacity of spare transformers owned by Energex but not currently in use. Cold Spare Capacity incorporates both spare capacity and cold capacity. Cold capacity is equipment which is already on site, with connections already in place so that the device can be brought into service merely by switching operations but which is not normally load carrying. Spare capacity also includes spare assets, on site, or in the store, where physical movement and / or making of connections would require manual intervention at the site of use.	Demonstrated in section 3.5.7.3.2 (Approach)

3.5.7.2 Sources

The zone substation transformer total installed capacities were extracted from the Substation Investment Forecasting Tool (SIFT) and Ellipse. This is outlined in Table 3.5.16 below:

Table 3.5.16 – Data Sources for distribution transformer total installed capacity

Variable Code	Variable	Source
DPA0601	Total installed capacity for first step transformation where there are two steps to reach distribution voltage	SIFT
DPA0602	Total installed capacity for second step transformation where there are two steps to reach distribution voltage	SIFT
DPA0603	Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage	SIFT
DPA0604	Total zone substation transformer capacity	SIFT
DPA0605	Cold spare capacity of zone substation transformers included in DPA0604	SIFT/Ellipse

Ellipse is an Enterprise Resource Planning system used by Energex to manage internal and external resources including assets, financial resources, materials, and human resources. It is grouped into sub-systems providing:

- Maintenance and repair scheduling;
- Workforce management, resource allocation, skills, training and payroll;
- Materials management and resource management; and
- Financial management.

3.5.7.3 Methodology

3.5.7.3.1 Assumptions

The following assumptions and limitations apply to the data:

- Active and hot standby substation transformer capacities have been included;
- No data has been excluded; and
- A snapshot of the data was taken at the end of the 2014/15 financial year.
- The following assumptions and limitations apply to the Cold Spare Capacity of zone substation transformers included in DPA0604 (DPA0605):

- The number and mix of assets held in stores varies each day. Stock levels are as of the 30th of June 2015;
- Spare capacity includes strategic spares as well as normal stock holding owned by Energex; and
- Cold capacity includes transformers that are in service but do not carry load under normal conditions or are not connected.

3.5.7.3.2 Approach

The following approach was applied to calculating the variables:

- The data was extracted from SIFT as at June each year and based on Normal Cyclic NCC rating which Energex uses to operate the network;

- The rating includes fans and allows for the load temperature rise test determined by the load profile;

- The following assets meet the definitions presented by the AER:
  - For DPA0601: 110 kV-33 kV or 132 kV-33 kV substations are a first step transformation where there are two steps to reach distribution voltage. These are referred to as bulk supply substations;
  - For DPA0602: 33 kV-11 kV substations are a second step transformation where there are two steps to reach distribution voltage. These are referred to as zone substations;
  - For DPA0603: 110 kV-11 kV or 132 kV-11 kV substations are a single step transformation to reach distribution voltage. These are referred to as direct transformation substations;
  - For DPA0604: the total capacities were the summation of all zone, bulk and direct transformation substation capacities; this also includes Cold Spare Capacity.
  - Cold capacity calculated for DPA0605 was subtracted from the SIFT extract to provide the final capacity value for DPA0601, DPA0602 and DPA0603.

Cold Spare Capacity of zone substation transformers included in DPA0604 (DPA0605) incorporates both cold capacity and spare capacity:

- The approach for calculating spare capacity was as follows:
  - The data was obtained via the INV004 – Stock on Hand by Warehouse and Item EPM report, generated from a database containing daily snapshots of inventory held in Ellipse;
  - Power transformer assets were extracted from the report as at the 30th of June 2015;
  - Power transformer assets not yet logged by the warehouse as stock on hand have been included;

- Power transformer capacity was extracted from the stock code description.

- The approach for calculating cold capacity was as follows:
  - The data was extracted from SIFT as at June each year and based on Normal Cyclic rating which Energex uses to operate the network;
  - The extract provided the standby capacity available at each substation.

3.5.7.4 Estimated Information

No Estimated Information was reported.

3.5.7.4.1 Justification for Estimated Information

Not applicable.

3.5.7.4.2 Basis for Estimated Information

Not applicable.

3.5.7.5 Explanatory Notes

Energex utilises a number of transformers in standby configurations where a transformer is in service but does not carry load under normal conditions. In this configuration the transformers are commissioned, connected to the network and only require switching (manual, remote or automatic) in order to carry load. The calculation of these variables required inputs to be disaggregated in order to separate standby (cold) capacity from total installed capacity. An example of this calculation is shown in Table 3.3.17:

Table 3.3.17 – Calculation of Total zone Substation transformer capacity for 2014/15

Variable Code	Variable	Breakdown	Units	Value
DPA0601	Total installed capacity for first step transformation where there are two steps to reach distribution voltage. i.e. 132/33 kV	In service	MVA	8116
		Standby (cold capacity)	MVA	-64.5
		total	**MVA**	**8051.5**
DPA0602	Total installed capacity for second step transformation where there are two steps to reach distribution voltage. i.e. 33/11 kV	In service	MVA	8406.5
		Standby (cold capacity)	MVA	-177.8
		total	**MVA**	**8228.7**
DPA0603	Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage. i.e. 110/11 kV	In service	MVA	4065.4
		Standby (cold capacity)	MVA	-172.2
		total	**MVA**	**3893**
DPA0604	Total zone substation transformer	**total**	**MVA**	**20980.4**

Variable Code	Variable	Breakdown	Units	Value
	capacity			
DPA0605	Cold spare capacity of zone substation transformers included in DPA0604	Total standby capacity for first step transformation where there are two steps to reach distribution voltage	MVA	64.5
		Total standby capacity for second step transformation where there are two steps to reach distribution voltage	MVA	177.8
		Total standby zone substation transformer capacity where there is only a single step transformation to reach distribution voltage	MVA	172.2
		Strategic spares	MVA	321.5
		Normal spares	MVA	71
		total	**MVA**	**807**

3.5.8 Public Lighting

The AER requires Energex to provide the following information relating to public lighting:

- **DPA0701 - Public lighting luminaires**
- **DPA0702 - Public lighting poles**

These variables are part of RIN Table 3.5.3 of Regulatory Template 3.5 – Physical Assets.

All information is Actual Information.

3.5.8.1 Consistency with EB RIN Requirements

Table 3.5.18 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.5.18 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report the number of public lighting luminaires and public lighting poles.	Demonstrated in section 3.5.8.3.2 (Approach)
For both variables the numbers provided must include both assets owned by Energex and assets operated and maintained by Energex but not owned by Energex.	Demonstrated in section 3.5.8.3.2 (Approach)
Only poles that are used exclusively for public lighting are to be included in the data.	Demonstrated in section 3.5.8.3.2 (Approach)

3.5.8.2 Sources

The number of public lighting luminaires and poles was extracted from the NFM database. This is outlined in Table 3.5.19 below.

Table 3.5.19 – Data Sources for Public Lighting

Variable Code	Variable	Source
DPA0701	Public lighting luminaires	NFM
DPA0702	Public lighting poles	NFM

The NFM database is the master electronic record of the public lighting assets and their connectivity. It is populated from completed field work orders and reflects the normal, as constructed state of the network.

3.5.8.3 Methodology

3.5.8.3.1 Assumptions

The following assumptions and limitations apply to the data relating to public lighting luminaires:

- Only rating 1[5] and 2[6] streetlights have been included in this count; and
- Streetlights data does not include assets that are in store or held for spares.

The following assumptions and limitations apply to the data relating to public lighting poles:

- The pole data does not include assets that are in store or held for spares;
- Only poles with a material type of 'steel' have been included;
- Only poles with a max voltage of LV or Unknown have been included;
- All timber poles have been excluded even when only a streetlight asset is installed.

3.5.8.3.2 Approach

The following approach was applied to calculating the variables:

- The data was obtained by running scripts through the NFM database for 2014/15. The scripts ensured that for both variables the data extracted included both assets owned by Energex, and assets operated and maintained by Energex but not owned by Energex. Further, only poles that are used exclusively for public lighting were included in the data.
- Separate scripts were run for each of the variables.
  - The Streetlight_By_Year.sql script was run to extract the data for the Public lighting luminaires.
  - The Poles_Streetlight_By_Year.sql was run to extract the data for the Public Lighting Poles.
- Once all of the data was extracted into Microsoft Excel for each of the required years, the data was combined into a master document and arranged into the AER Template format.

The data was validated by checking the results against the Energex Annual Report and Distribution Annual Planning Report. In cases where the unexplained variance was greater than 1%, the differences was investigated and resolved.

[5] Rating 1 - A streetlight designed, constructed, owned and operated (maintained) by Energex.
[6] Rating 2 - A streetlight where the customer designs and constructs the light which is owned, operated and maintained by Energex.

3.5.8.4 Estimated Information

No Estimated Information was reported.

3.5.8.4.1 Justification for Estimated Information

Not applicable.

3.5.8.4.2 Basis for Estimated Information

Not applicable.

3.6 Quality of Services

3.6.1 Reliability

The AER requires Energex to provide the following information relating to network reliability measures:

- **DQS0101 - Whole of network unplanned SAIDI**
- **DQS0102 - Whole of network unplanned SAIDI excluding excluded outages**
- **DQS0103 - Whole of network unplanned SAIFI**
- **DQS0104 - Whole of network unplanned SAIFI excluding excluded outages**

As well as the following measures exclusive of major event days

- **DQS0105 - Whole of network unplanned SAIDI**
- **DQS0106 - Whole of network unplanned SAIDI excluding excluded outages**
- **DQS0107 - Whole of network unplanned SAIFI**
- **DQS0108 - Whole of network unplanned SAIFI excluding excluded outages**

These variables are a part of Regulatory Template 3.6 – Quality of Services.

All information is Actual Information.

3.6.1.1 Consistency with EB RIN Requirements

Table 3.6.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.6.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Reliability data must be reported in accordance with the definitions provided in the AER's Service Target Performance Incentive Scheme (STPIS) unless otherwise specified.	Reporting is in accordance with the 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 Customers. SAIDI excludes momentary interruptions (interruptions of one minute or less)."	System wide SAIDI is provided in accordance with the template and includes all outages resulting in an unplanned interruption to customer supply that occurs for greater than one minute.
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).	System wide SAIFI is provided in accordance with the template and includes all outages resulting in an unplanned interruption to customer supply that occurs for greater than one minute.
An unplanned interruption is an interruption due to	Reliability data has been reported in accordance

Requirements (instructions and definitions)	Consistency with requirements
an unplanned event. An unplanned event is an event that causes an interruption where the customer has not been given the required Notice for the interruption or where the customer has not requested the outage.	with the definitions provided in the AER's STPIS for unplanned SAIDI and SAIFI.
The SAIDI and SAIFI measures must also be reported exclusive of specific outages as defined by the AER. Excluded Outages are: • load shedding due to a generation shortfall • automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition • load shedding at the direction of the Australian Energy Market Operator (AEMO) or a system operator • load interruptions caused by a failure of the shared transmission network • load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning • load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.	Exclusions of outages were performed in accordance with the AER's instructions and the STPIS Guidelines.
The MED threshold must be calculated for the 2012/13 Regulatory Year in accordance with the requirements in the STPIS. The MED threshold calculated for 2012/13 must then be applied as the MED threshold for Regulatory Years prior to 2012/13 for the purpose of calculating SAIDI and SAIFI exclusive of MEDs as per the STPIS.	The MED threshold calculated for 2014/15 Regulatory Year is in accordance with the STPIS definition and is applied to 2014/15 system results.

3.6.1.2 Sources

Energex has used outage data from three sources, NFM (Network Facilities Management), EPM (Energex Performance Management) and PON OMS (Power On Outage Management

System). These combined sources were queried to retrieve all transformer interruptions with their customer counts and durations.

Table 3.6.2 – Data Sources

Variable Code	Variable	Source
DQS0101	Whole of network unplanned SAIDI	EPM/PON
DQS0102	Whole of network unplanned SAIDI excluding excluded outages	EPM/PON
DQS0103	Whole of network unplanned SAIFI	EPM/PON
DQS0104	Whole of network unplanned SAIFI excluding excluded outages	EPM/PON
DQS0105	Whole of network unplanned SAIDI (excluding MEDs)	EPM/PON
DQS0106	Whole of network unplanned SAIDI excluding excluded outages (excluding MEDs)	EPM/PON
DQS0107	Whole of network unplanned SAIFI (excluding MEDs)	EPM/PON
DQS0108	Whole of network unplanned SAIFI excluding excluded outages (excluding MEDs)	EPM/PON
Customer Counts	System Customer base	NFM

3.6.1.3 Methodology

Energex has used outage data from the corporate reporting system EPM (Energex Performance Management) which is supplied outage information by the newly introduced PON OMS (Power On Outage Management System). EPM was queried for all unplanned sustained transformer interruptions to retrieve customer minutes interrupted (CMI) and Customers Interrupted (CI). The customer base used is sourced from NFM.

3.6.1.3.1 Assumptions

1) All variables have been calculated exclusive of momentary interruptions as defined in the SAIDI and SAIFI definitions as ≤1 minute

2) From the raw source data (248,018 records) there were 291 sustained transformer interruptions (Exclude planned and STPIS MED) that had a valid outage report number but no category due to no feeder allocation at the time of the outage.

These interruptions were not included in the data used for the yearly SAIDI and SAIFI values. This equated to a CMI of 511,047 and CI of 3,977 represented as a system SAIDI and SAIFI value as below:

System SAIDI = 0.37 minutes

System SAIFI = 0.0028 interruptions

3.6.1.3.2 Source Data

1) CMI and CI – A daily listing of CMI and CI was retrieved from EPM resulting in a listing of 365 records.

2) Customer Base – The 1,382,273 system customers at the start and 1,403,864 at the end of the reporting period were averaged to create a regulatory customer base of 1,393,068.

3.6.1.3.3 Approach

1) The CMI and CI figures for all outages greater than 1 min in duration were extracted from the outages table and summated into a daily figure (columns [C] and [D] below).

2) The daily CMI and CI figures that are to be excluded for variables DSQ0102, DSQ0104, DSQ0106 and DSQ0108 were also extracted from the same table (columns [E] and [F] below).

[A]	[B]	[C]	[D]	[E]	[F]	[G]
FINYEAR	**DATE**	**ALL CMI**	**ALL CI**	**Excl CMI**	**Excl CI**	**AER_CUST**
2015	1/07/2014	336497.1135	3710			1393068
2015	2/07/2014	24923.8447	295			1393068
2015	3/07/2014	179829.1421	2873			1393068

3) An AER compliant yearly average customer number was calculated and assigned to each corresponding year of CMI and CI data (column [G] above).

4) The daily standard SAIDI and SAIFI figures were first calculated as $\frac{\text{CMI}}{\text{\# Customers}}$ and $\frac{\text{CI}}{\text{\# Customers}}$ respectively. The daily SAIDI and SAIFI figures were then calculated with the exclusion of specific outages as stated by the AER.

5) These calculations can be seen in columns [H], [I], [M] and [N] below:

[H]	[I]	[J]	[K]	[L]	[M]	[N]
DQS0101	DQS0103				DQS0102	DQS0104
ALL SAIDI	ALL SAIFI	Excl SAIDI	Excl SAIFI	Excl Flag	All SAIDI Less Excl	All SAIFI Less Excl
0.2415511	0.00266319	0	0	NO	0.241551104	0.00266319
0.01789133	0.00021176	0	0	NO	0.017891334	0.00021176
0.12908856	0.00206235	0	0	NO	0.12908856	0.00206235

6) The daily SAIDI and SAIFI figures were then aggregated for 2015 financial year to obtain variables DSQ0101 – DSQ0104.

7) To exclude MEDs from the SAIDI and SAIFI calculations the MED threshold was calculated for the 2015 Regulatory Year in accordance with the STPIS guidelines7. This used the historical five year data for SAIDI (2010 - 2014) less exclusions (column [M] above). The TMED calculation for 2015 Regulatory Year = 3.20 minutes.

8) Using TMED each day was flagged as either a major event day or not. The same calculations for variables DSQ0101 – DSQ0104 were then performed on the data exclusive of major event day to obtain variables DSQ0105 – DSQ0108.

9) The example calculations can be seen in columns [O] to [V] below:

[O]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]
Tmed 12/13	Tmed13/14	Tmed 14/15	Tmed 15/16				
3.32	3.41	3.20	3.32	DQS0105	DQS0107	DQS0106	DQS0108
Ln All SAIDI Less Excl	MED	SAIDI MED	SAIFI MED	All SAIDI Less MED	All SAIFI Less MED	All SAIDI Less Excl Less MED	All SAIFI Less Excl Less MED
-1.42067422	NO	0	0	0.2415511	0.00266319	0.2415511	0.00266319
-4.02343882	NO	0	0	0.01789133	0.00021176	0.01789133	0.00021176
-2.0472566	NO	0	0	0.12908856	0.00206235	0.12908856	0.00206235

3.6.1.4 Estimated Information

No estimated Information was Reported.

3.6.1.4.1 Justification for Estimated Information

Not applicable.

3.6.1.4.2 Basis for Estimated Information

Not applicable.

[7] Electricity distribution network service providers - Service target performance incentive scheme, November 2009 – Appendix D: Major Event Days

3.6.2 Energy Not Supplied

The AER requires Energex to provide the following information relating to energy not supplied to customers:

- **DQS0201 - Energy Not Supplied (planned)**
- **DQS0202 - Energy Not Supplied (unplanned)**
- **DSQ02 – Energy Not Supplied - Total**

These variables are a part of Regulatory Template 3.6 – Quality of Services.

All information is Estimated Information.

3.6.2.1 Consistency with EB RIN Requirements

Table 3.6.3 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.6.3 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions	Demonstrated in section 3.6.2.3 (Methodology)
DNSP must estimate the raw (not normalized) energy not supplied due to unplanned customer interruptions based on average customer demand (multiplied by the number of customers interrupted and the duration of the interruption). Average customer demand must be determined from (in order of preference): 1. average consumption of the customers interrupted based on their billing history; 2. feeder demand at the time of the interruption divided by the number of customers on the feeder; 3. average consumption of customers on the feeder based on their billing history; 4. average feeder demand derived from feeder Maximum Demand and estimated load factor, divided by the number of customers on the feeder.	Demonstrated in section 3.6.2.3 (Methodology)
Energy not supplied should be reported exclusive of the effect of Excluded Outages as defined in chapter 9	Demonstrated in section 3.6.2.3 (Methodology)

3.6.2.2 Sources

Table 3.6.4 below details the source systems used to obtain information for each of the required variables:

Table 3.6.4 – Data Sources

Variable Code	Variable	Unit	Source
DQS0201	Energy Not Supplied (planned)	GWh	EPM / NFM / PEACE
DQS0202	Energy Not Supplied (unplanned)	GWh	EPM / NFM / PEACE
DSQ02	Energy Not Supplied – Total	GWh	EPM / NFM / PEACE

3.6.2.3 Methodology

- Energex calculated the energy not supplied to customers as per AER's preference number 3 (average consumption of customers on the feeder based on their billing history).
- In extracting the outage data the outages exclude generation/transmission events and momentary interruptions but include major event days. This aligns to the AER's requirement of "raw (not normalized) energy not supplied due to unplanned customer interruptions".

3.6.2.3.1 Assumptions

The following assumptions have been applied to calculating the required variables:

- Using a 12 month total for customer energy consumption assumes that there is no load variation for outages which occur at differing times, days, or months. The materiality of this assumption will be low as outages are relatively evenly spread over time in a 12 month period.
- Where feeder customer energy consumption information cannot be determined the "system" customer average (i.e. total system energy consumption divided by total number of customers) is used.
- At the time of preparation of the 2014/15 figures, customer energy consumption was only available up to March 2015. This is due to customer meter data being manually read on a quarterly basis. Therefore, the period of 1 April 2014 to 31 March 2015 was used as the annual energy consumption for each feeder.

- Data was only available for the current network configurations and as such all calculations were based on these figures.

3.6.2.3.2 Approach

1) The total energy consumed on each feeder was collated based on customer billing data (ultimately sourced from PEACE).

   The current number of customers on each feeder was extracted from the Energex NFM system.

   The customer minutes lost for each feeder during 2014/15 was extracted from the Energex EPM system for both planned and unplanned outages. Customer minutes lost is calculated within EPM, and is the number of customers interrupted for each outage multiplied by the duration of the outage.

2) Average annual energy consumption per customer was calculated for each feeder by dividing the feeder's total energy consumption by the number of customers on each feeder.

3) The average customer energy consumption per feeder was then mapped to the feeder outage data from 2014/15. Where the energy was unable to be mapped to the outage data for a particular feeder, the energy was stated as the "system wide" customer average.

4) The energy not supplied for a particular feeder and outage type (planned or unplanned) was then calculated as:

$$ENS_i = \frac{Customer\ Minutes\ Lost_i \ \times Average\ Customer\ Energy\ Consumption_i}{Number\ of\ minutes\ per\ year\ (525{,}600)}$$

5) The feeder energy not supplied values were then summated to give overall figures for energy not supplied (planned) and energy not supplied (unplanned).

6) There is a small portion of the overall supplied energy which has not been able to be assigned to a feeder. In 2014/15, this portion was 4.7% of the total energy sales. To adjust for this shortfall, the calculated energy not supplied figures were increased by this portion to determine the final energy not supplied figures.

3.6.2.4 Estimated Information

All information is Estimated Information.

3.6.2.4.1 Justification for Estimated Information

Customer meter data is manually read on a quarterly basis, leading to delays in the financial year's data being available for the Energy Not Supplied calculation. As customer energy consumption data is currently only available up to March 2015 and not the complete financial year, all values are currently considered "Estimated".

3.6.2.4.2 Basis for Estimated Information

The latest available 12 months of energy consumption was used in the calculation. For details and assumptions please see the methodology section above.

3.6.3 System losses and capacity utilisation

The AER requires Energex to provide the following information relating to system losses and capacity utilisation:

- **DQS03 – System losses**
- **DQS04 – Overall capacity utilisation**

These variables are a part of Regulatory Template 3.6 – Quality of Service.

All information is Actual Information.

3.6.3.1 Consistency with EB RIN Requirements

Table 3.6.5 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.6.5 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
System losses are the proportion of energy that is lost in distribution of electricity from the transmission network to Energex customers. Energex must report distribution losses calculated via the following equation: $system\ losses = \frac{electricity\ imported - electricity\ delivered}{electricity\ imported} \times 100$ This is a system wide figure inclusive of inflows from Embedded Generation and outflows to other DNSPs.	Energex has calculated system losses in line with the guidance provided by the AER. Refer to section 3.6.3.3 (Methodology) for details.
Capacity utilisation is a measure of the capacity of zone substation transformers that is utilized each year. Energex must report the sum of non-coincident Maximum Demand at the zone substation level divided by summation of zone substation thermal capacity. For the purpose of this measure, thermal capacity is the rated continuous load capacity of the zone substation (with forced cooling or other capacity improving factors included if relevant). This must be the lowest of either the transformer capacity or feeder exit capacity of the zone substation. Feeder exit capacity should similarly be the continuous rating.	Energex has calculated capacity utilisation in line with the guidance provided by the AER. Refer to section 3.6.3.3 (Methodology) for details.

3.6.3.2 Sources

Table 3.6.6 below details the source systems used to obtain information for each of the required variables:

Table 3.6.6 – Data Sources

Variable Code	Variable	Source
DQS03	System losses	Published Distribution Loss Factor (DLF) Repots, Metering systems, PEACE
DQS04	Overall capacity utilisation	SIFT (for ratings), SCADA (for load)

3.6.3.3 Methodology

Both variables were calculated using the methodology specified by the AER.

3.6.3.3.1 Assumptions

No Assumptions were made.

3.6.3.3.2 Approach

System Losses

System loss figures are reported by Energex in the DLF reports each year. The DLF reports are calculated in the same manner to that specified by the AER for the EB RIN.

Two figures are required for the calculation of system losses, the electricity imported into the system and the electricity delivered from the system. The system loss percentage is then calculated as the energy loss divided by the total energy imported into the system.

- Electricity imported into the Energex network was obtained from metering data at system input points and summated for each Regulatory Year.
- Electricity sold to customers and exported from the system was obtained from the Energex billing system (PEACE) and was summated for each Regulatory Year. The difference between these two figures was then calculated as the energy lost from the distribution system.
- The percentage system losses was then calculated using the following equation:

$$system\ losses = \frac{electricity\ imported - electricity\ delivered}{electricity\ imported} \times 100$$

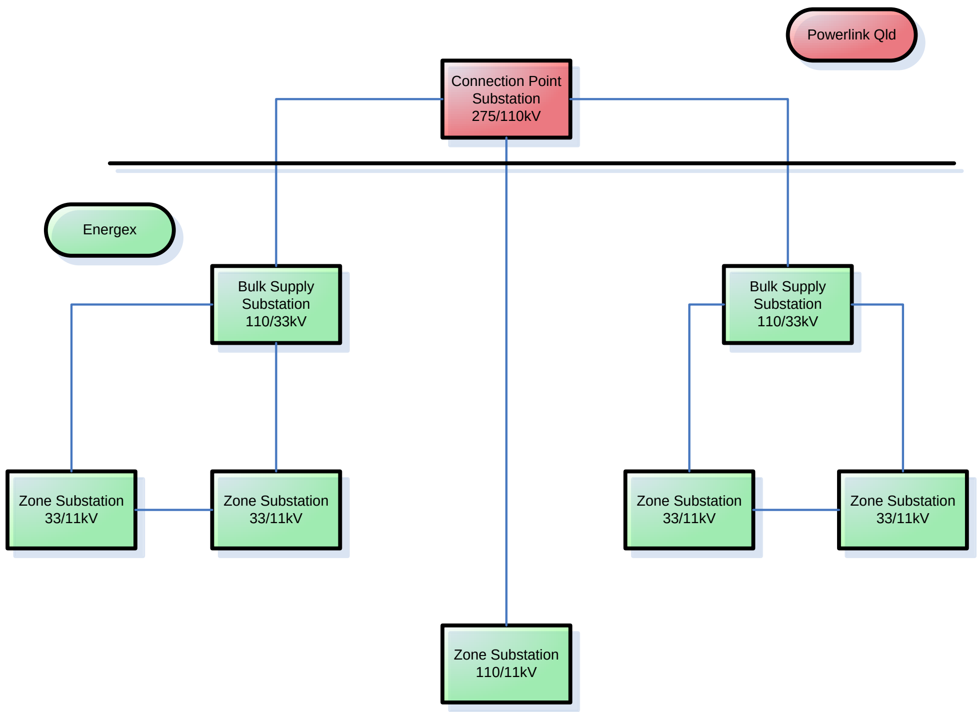
Capacity Utilisation

The network capacity utilisation is calculated as the percentage utilisation of zone sub-station thermal capacity. This is calculated using the total network non-coincident maximum demand divided by the total network zone sub-station thermal capacity as specified by the AER.

1) The total network non-coincident maximum demand was obtained from the Energex SCADA system and summated for each Regulatory Year.

2) The zone substation thermal capacity was extracted from the Energex SIFT and ERAT systems for each Regulatory Year. The thermal capacities included the nameplate capacities as well as any extra capacity added for cooling upgrades.

The calculation specified by the AER is not correct for estimating overall system utilisation. DPA0604 is a summation of the Energex bulk supply and zone substation capacities. The correct calculation should only include the final step of transformation (DPA0602 and DPA0603).



The diagram of the Energex supply network shows the zone substation load being supplied via bulk supply substations except in the case where direct transformation substations (110/11kV) are employed. DPA0601 is the 110/33kV bulk supply substation capacity to a meshed network supplying the 33/11kV zone substations.

3.6.3.4 Estimated Information

No Estimated Information was reported.

3.6.3.4.1 Justification for Estimated Information

Not applicable.

3.6.3.4.2 Basis for Estimated Information

Not applicable.

3.7 Operating Environment

3.7.1 Rural Proportion

The AER requires Energex to provide the following information relating to rural proportion:

- **DOEF0201 – Rural proportion of line length**

This is as a part of Regulatory 3.7 – Operating Environment Factors.

All information is Actual Information.

3.7.1.1 Consistency with EB RIN Requirements

Table 3.7.1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.7.1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Rural Proportion is Distribution line route length classified as short rural or long rural in km / total network Line Length.	Demonstrated in section 3.7.1.3.2 (Approach.)
Total network Line Length is the aggregate length in kilometres of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag.	This definition of Line Length was applied.

3.7.1.2 Sources

Table 3.7.2 below details the source systems used to obtain information for each of the required variables:

Table 3.7.2 – Data Sources

Variable Code	Variable	Source
DOEF0201	Rural proportion	ArcGIS

3.7.1.3 Methodology

- All data to calculate the rural proportion variable was obtained through ArcGIS.
- These figures were then used to calculate the proportion of rural overhead line length for each individual year.
- Rural proportion, expressed as a percentage, was then calculated by dividing total rural overhead line length, by route line length (which included underground circuit lengths in accordance with direction provided by the AER 9 April 2014).

3.7.1.3.1 Assumptions

The calculation of this variable assumed that:

- A rural area is defined by the level of demand on a network. The following ranges were used for the calculation of rural overhead line length:
  - Urban/CBD: >300 kVA/km
  - Rural: ≤300 kVA/km
- Underground route lengths are assumed as urban.

3.7.1.3.2 Approach

1) A GIS "shapefile" was generated within ArcGIS system that defined the boundaries of where the network was considered "Rural" or "Urban". This was built on the assumption that a rural area could be defined as having a network demand of ≤300 kVA/km.
2) The line length within the rural boundaries was then calculated by the GIS system to give a total rural proportion for each year.

3.7.1.4 Estimated Information

No Estimated Information was reported.

3.7.1.4.1 Justification for Estimated Information

Not applicable.

3.7.1.5 Explanatory Notes

- Energex has only "short rural" line lengths. The value of the rural proportion has altered from previous years due to recalculation of urban / rural areas and a new release of ArcGIS which reportedly provides more accurate information.

- Energex notes that the inclusion of the underground network in route line length has skewed the overall rural proportion. As noted in the Basis of Preparation for Route Line Length, Energex considers that the inclusion of underground network in vegetation management benchmarking is inappropriate given that work is driven by the overhead network.

3.7.2 Maintenance Spans and Tree Numbers

The AER requires Energex to provide the following information relating to maintenance spans and tree numbers:

- **DOEF0202 – Urban and CBD vegetation maintenance spans**
- **DOEF0203 – Rural vegetation maintenance spans**
- **DOEF0204 – Total vegetation maintenance spans**
- **DOEF0208 – Average number of trees per urban and CBD vegetation maintenance span**
- **DOEF0209 – Average number of trees per rural vegetation maintenance span**

These variables are a part of Regulatory Template 3.7 – Operating Environment Factors.

All information Actual Information.

3.7.2.1 Consistency with EB RIN Requirements

Table 3.7.3 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.7.3 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
A vegetation maintenance span 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 3.7.2.3.2 (Approach)
If Energex has Actual Information, Energex must report all years of available data. If Energex does not have Actual Information on these variables, then it must estimate data for the most recent Regulatory Year.	Energex uses Actual Information

3.7.2.2 Sources

Table 3.7.4 details the source systems used to obtain information for each of the required variables:

Table 3.7.4 – Data Sources

Variable Code	Variable	Unit	Source
DOEF0202	Urban and CBD vegetation maintenance spans	Number of spans	Field Surveys
DOEF0203	Rural vegetation maintenance spans	Number of spans	Field Surveys
DOEF0204	Total vegetation maintenance spans	Number of spans	Field Surveys
DOEF0208	Average number of trees per urban and CBD vegetation maintenance span	Trees	Field Surveys
DOEF0209	Average number of trees per rural vegetation maintenance span	Trees	Field Surveys

3.7.2.3 Methodology

Energex has determined both the number of vegetation management spans and the average number of trees per maintenance span using a statistical sampling methodology. This was performed for both Urban/CBD and Rural areas to obtain the figures.

3.7.2.3.1 Assumptions

The following assumptions underpin the values provided:

- 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 when sampling the number of trees per maintenance span were trees within that span that require active maintenance or could be reasonably seen to require active maintenance in the future.
- Sampling of network spans to identify the portion of maintenance spans was undertaken on the distribution network, and it was assumed that the portion of maintenance spans on the distribution network is the same as that for the sub-transmission network.

3.7.2.3.2 Approach

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. The variable "DOEF0204 – Total Vegetation Maintenance Spans" was then calculated as the sum of the Urban/CBD and Rural variables.

Obtaining span sample:

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 Assumptions above. This shapefile was then used to calculate the total population sizes of Urban/CBD and Rural spans in Energex's distribution network i.e. 33 kV and below (the spans of Energex's subtransmission network were not included in sample populations).

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 (2940 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 ID number was generated from http://www.randomizer.org/ 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 required active maintenance or could be reasonably seen to require active maintenance in the future were counted.

Calculation of variables:

1) 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.

2) The total number of maintenance spans was calculated as the addition of urban/CBD and rural maintenance spans.

3) The sample average number of trees per vegetation maintenance span for urban/CBD and rural areas was taken as the average for the entire population.

3.7.2.4 Estimated Information

No Estimated Information was used.

3.7.2.4.1 Justification for Estimated Information

Not applicable.

3.7.2.4.2 Basis for Estimated Information

Not applicable.

3.7.2.5 Explanatory Notes

Information was based on statistical sampling. The field survey method 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.

3.7.3 Span numbers, tropical proportion and bushfire risk

The AER requires Energex to provide the following information relating to span numbers, tropical proportion and bushfire risk:

- **DOEF0205 – Total number of spans**
- **DOEF0212 – Tropical proportion**
- **DOEF0214 – Bushfire risk**

These variables are a part of Regulatory Template 3.7 – Operating Environment Factors and were obtained from the Energex Geographical Information System.

All information is Actual Information.

3.7.3.1 Consistency with EB RIN Requirements

Table 3.7.5 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.7.5 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
If DNSP records poles rather than spans, the number of spans is the number of poles less one	Energex records spans.
The tropical proportion is the approximate total number of urban and Rural Maintenance Spans in the Hot Humid Summer and Warm Humid Summer regions as defined by the Australian Bureau of Meteorology Australian Climatic Zones map (based on temperature and humidity).	Demonstrated in section 3.7.3.3.2 (Approach).
The bushfire risk variable is the number of Maintenance Spans in high bushfire risk areas as classified by a person or organisation with appropriate expertise on fire risk. This includes but is not limited to: – DNSP's jurisdictional fire authority – local councils – insurance companies – DNSP's consultants	Demonstrated in section 3.7.3.3.2 (Approach).

Requirements (instructions and definitions)	Consistency with requirements
– Local fire experts	
If DNSP has Actual Information, DNSP must report all years of available data. If DNSP does not have Actual Information on these variables, then it must estimate data for the most recent Regulatory Year.	These figures are Actual Information.

3.7.3.2 Sources

Table 3.7.6 below details the source systems used to obtain information for each of the required variables:

Table 3.7.6 – Data Sources

Variable Code	Variable	Source
DOEF0205	Total number of spans	ArcGIS
DOEF0212	Tropical proportion	ArcGIS/ BOM
DOEF0214	Bushfire risk	ArcGIS/ Queensland Government

3.7.3.3 Methodology

- Energex has calculated the total number of overhead spans, the tropical proportion spans and the bushfire risk spans using ArcGIS. This incorporated shapefiles from the Bureau of Meteorology and the Queensland Government to obtain the number of spans within tropical and bushfire risk areas.
- It is noted that the Queensland Government has made changes to bushfire layers which are reflected in the changed values compared to the previous EBRIN.

3.7.3.3.1 Assumptions

No assumptions were made.

3.7.3.3.2 Approach

1) The total number of overhead spans was obtained by extracting the figures directly from ArcGIS.

2) The tropical proportion variable was calculated by overlaying the Australian Bureau of Meteorology Australian Climatic Zones GIS shapefile8 on the Energex maps. From here the total number of overhead spans that fell within the tropical regions was calculated by the GIS system. This figure was then multiplied by the total proportion of maintenance spans to non-maintenance spans from the calculated variables DOEF0204 and DOEF0205 to give the number of maintenance spans in a tropical area.

3) The bushfire risk variable was calculated by overlaying the Queensland Government Department of State Development, Infrastructure and Planning Bushfire Risk GIS shapefile9 on the Energex maps. From here the number of overhead spans that fell within the bushfire risk regions was counted by the GIS system. This figure was then multiplied by the total proportion of maintenance spans to non-maintenance spans from the calculated variables DOEF0204 and DOEF0205 to give the number of maintenance spans in a bushfire risk area. Variation in figures from previous years can be attributed to a change in the area covered by the Bushfire Risk Shapefile.

3.7.3.4 Estimated Information

No Estimated Information was reported.

3.7.3.4.1 Justification for Estimated Information

Not applicable.

3.7.3.4.2 Basis for Estimated Information

Not applicable.

3.7.3.5 Explanatory Notes

- The figure for DOEF0204 were determined using a statistical sampling methodology outlined in Basis of Preparation 3.7.2. Estimated information was calculated by multiplying the actual figures for total number of spans in a tropical or bushfire risk areas by the statistically calculated proportion of total maintenance spans to total spans.

- Underground network was not included in these calculations as the instructions specifically seek span numbers. Further, bushfire risk and tropical portion were not deemed relevant to the underground network.

[8] http://www.bom.gov.au/climate/averages/climatology/gridded-data-info/gridded-climate-data.shtml
[9] http://www.dsdip.qld.gov.au/about-planning/spp-mapping-online-system.html

3.7.4 Maintenance Cycles

The AER requires Energex to provide the following information relating to maintenance cycles:

- **DOEF0206 – Average urban and CBD vegetation maintenance span cycle**
- **DOEF0207 – Average rural vegetation maintenance span cycle**

These variables are a part of Regulatory 3.7 – Operating Environment Factors.

All information is Actual Information.

3.7.4.1 Consistency with EB RIN Requirements

Table 3.7.7 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.7.7 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Maintenance span cycle is the planned number of years (including fractions of years) between which cyclic vegetation maintenance is performed for the relevant area	Demonstrated in section 3.7.4.3 (Methodology).
CBD and Urban Maintenance Spans refer to CBD and urban areas that are subject to vegetation management practices in the relevant year. CBD and urban areas are consistent with CBD and urban customer classifications.	Demonstrated in sections 3.7.4.3.1 (Assumptions) and **Error! Reference source not found.** (Approach).
Rural Maintenance Spans are spans in rural areas that are subject to vegetation management practices in the relevant year. Rural spans include spans in short rural and long rural feeders. Rural areas must be consistent with rural short and rural long feeders.	Demonstrated in sections 3.7.4.3.1 (Assumptions) and **Error! Reference source not found.** (Approach).

3.7.4.2 Sources

Table 3.7.8 details the source systems used to obtain information for each of the required variables:

Table 3.7.8 – Data Sources

Variable Code	Variable	Source
DOEF0206	Average urban and CBD vegetation maintenance span cycle	ArcGIS/vegetation management contracts
DOEF0207	Average rural vegetation maintenance span cycle	ArcGIS/vegetation management contracts

3.7.4.3 Methodology

Energex provided the DOEF0206 and DOEF0207 values using a weighted average of the Maintenance Span Cycles within urban/CBD and rural areas. The figures were based on the current and historical vegetation management contracts which stipulated the cycle lengths.

3.7.4.3.1 Assumptions

A rural area is defined by the level of demand on a network. Consistent with CBD and urban customer classifications, the following ranges were used to define a rural span:

- Urban/CBD: >300 kVA/km
- Rural: ≤300 kVA/km

3.7.4.3.2 Approach

Energex uses a supplier managed program to determine maintenance span cycles. The suppliers work program is based on post codes and since they report on start and completion dates, the relevant cycle time for each maintenance span can be derived.

For each of the maintenance spans, Energex can classify into Urban/CBD and Rural using the ArcGIS shapefile for Urban/CBD (DOEF0202) and Rural (DOEF0201).

The average maintenance cycle is then derived as follows:

- For each postcode it was determined when an invoice was received and the length of time in months which had elapsed since the previous invoice had been received. Each postcodes was then split into its urban/rural component and an appropriate weighting for its length was applied. It's time elapsed in months was applied to the individual section. The average over all postcodes was then used for the figure in the RIN table.

3.7.4.4 Estimated Information

No Estimated Information was reported.

Not applicable.

3.7.4.4.1 Basis for Estimated Information

Not applicable.

3.7.5 Defects

The AER requires Energex to provide the following information relating to defects:

- **DOEF0210 – Average number of defects per urban and CBD vegetation maintenance span**
- **DOEF0211 - Average number of defects per rural vegetation maintenance span**

These variables are a part of Regulatory 3.7 – Operating Environment Factors.

All information is Actual Information.

3.7.5.1 Consistency with EB RIN Requirements

Table 3.7.9 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.7.9 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
DNSP must report the average number of vegetation related Defects that are recorded per Maintenance Span in the relevant year.	Demonstrated in section 3.7.5.3.2 (Approach)
A Defect is any recorded incidence of noncompliance with a NSP's vegetation clearance standard. This also includes vegetation outside a NSP's standard clearance zone that is recognised as hazardous vegetation and which would normally be reported as requiring management under the NSPs Inspection practices.	Demonstrated in section 3.7.5.3.2 (Approach)
In its basis of preparation, Energex must specify whether it records the total number of Defects for each vegetation Maintenance Span, or whether it records Defects on a vegetation Maintenance Span as one, regardless of the number of Defects on the span.	Energex does not record defects on either basis. Further discussion of this is provided in section 3.7.5.3.2 (Approach)
If Energex has Actual Information, Energex must report all years of available data. If Energex does not have Actual Information on these variables, then it must estimate data for the most recent Regulatory Year.	Energex has Actual Information
CBD and Urban Maintenance Spans refers to CBD and urban areas that are subject to vegetation management practices in the relevant year. CBD and urban areas are	Demonstrated in section 3.7.5.3.1 (Assumptions)

Requirements (instructions and definitions)	Consistency with requirements
consistent with CBD and urban customer classifications.	
Rural Maintenance Spans are spans in rural areas that are subject to vegetation management practices in the relevant year. Rural spans include spans in short rural and long rural feeders. Rural areas must be consistent with rural short and rural long feeders.	Demonstrated in section 3.7.5.3.1 (Assumptions)

3.7.5.2 Sources

Table 3.7.10 below details the source systems used to obtain information for each of the required variables:

Table 3.7.10 – Data Sources

Variable Code	Variable	Source
DOEF0210	Average number of defects per urban and CBD vegetation maintenance span	Contract records
DOEF0211	Average number of defects per rural vegetation maintenance span	Contract records

3.7.5.3 Methodology

Energex has provided Actual Information for the average number of defects per maintenance span for both urban/CBD and rural areas. This was calculated as the actual number of defects recorded in the system, divided by the calculated number of maintenance spans. It is noted that defects reporting is unable to distinguish between urban and rural.

3.7.5.3.1 Assumptions

The following assumptions were applied:

- 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
- There is no statistical difference between the averages of urban/CBD and rural defects per maintenance span and thus the overall average of defects per maintenance span is a valid representation of both populations.

3.7.5.3.2 Approach

- The data for the number of defects was gathered from records of non-compliance on field services contract audits. These audits indicate the number of non-conformances issued to the contractors by Energex contract officers.
- Importantly, Energex records the number of defects on a vegetation management span as one defect per vegetation management area. The Energex vegetation management policy states that, upon audit, only that a minimum number of defects needs be recorded in an area for it to be classed as non-compliant. From here the contractor responsible for the site is ordered to rework the area and a single “defect” is recorded.
- These defect numbers were then divided by the previously calculated number of vegetation maintenance spans (for details of calculation refer to the basis of preparation 3.7.2 - Maintenance Spans and Tree Numbers for variables DOEF0202 to DOEF0204) to obtain an average number of defects per maintenance span.

3.7.5.4 Estimated Information

No Estimated Information was reported.

3.7.5.4.1 Justification for Estimated Information

Not applicable.

3.7.5.4.2 Basis for Estimated Information

Not applicable.

3.7.5.5 Explanatory Notes

- Energex recorded 6 non-conformances across its network in 2014/15. The figure is too low to appear in table 3.7 but it is 0.0000144542. Energex is aware that it has more defects than this but these defects do not meet the definition provided by the AER as they are neither recorded nor deemed a non-compliance.

3.7.6 No Standard Vehicle Access

The AER requires Energex to provide the following information relating to standard vehicle access:

- **DOEF0213 – Standard vehicle access**

This variable is a part of Regulatory 3.7 – Operating Environment Factors.

All information is Estimated Information.

3.7.6.1 Consistency with EB RIN Requirements

Table 3.7.11 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.7.11 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Standard vehicle access is "Distribution route Line Length that does not have Standard Vehicle Access. Areas with Standard Vehicle Access are serviced through made roads, gravel roads and open paddocks (including gated and fenced paddocks). An area with no Standard Vehicle Access would not be accessible by a two wheel drive vehicle.	Energex does not have data regarding line length serviced through the areas specified; or that cannot be accessed by a two wheel drive vehicle. It has therefore used line length on road reserve as a proxy.
Route line length is "the aggregate length in kilometres of lines, measured as the length of each span between poles and/or towers, and where the length of each span is considered only once irrespective of how many circuits it contains. This is the distance between line segments and does not include vertical components such as line sag."	Route line length is based on GIS system distance and does not include vertical components.
If DNSP has Actual Information, DNSP must report all years of available data. If DNSP does not have Actual Information on these variables, then it must estimate data for the most recent Regulatory Year	In the absence of Actual Information Energex has estimated figures for standard vehicle access for the most recent Regulatory Year using the Energex GIS as the distribution route line length that does not fall within the road reserve.

3.7.6.2 Sources

Table 3.7.12 below details the source systems used to obtain information for each of the required variables:

Table 3.7.12 – Data Sources

Variable Code	Variable	Unit	Source
DOEF0213	Standard vehicle access	km	ArcGIS

3.7.6.3 Methodology

The distribution route line length with standard vehicle access was estimated by identifying the line length that falls within the known road reserve boundaries. This was subtracted from total route line length to find the distribution route line length that does not have standard vehicle access.

3.7.6.3.1 Assumptions

- It is assumed that the route line length that does not fall within road reserve boundaries is an appropriate proxy for standard vehicle access, as this line cannot typically be accessed by standard vehicles.

3.7.6.3.2 Approach

- The distribution route line length with standard vehicle access was estimated by identifying the line length that falls within the known road reserve boundaries. This was calculated within ArcGIS by overlaying the distribution line segments with the known road reserve boundaries and counting the line segments within those boundaries. This was subtracted from total route line length to find the distribution route Line Length that does not have Standard Vehicle Access.

3.7.6.4 Estimated Information

Variable DOEF0213 – Standard vehicle access is Estimated Information.

3.7.6.4.1 Justification for Estimated Information

The figures were estimated as Energex does not measure the distribution route line length with standard vehicle access.

3.7.6.4.2 Basis for Estimated Information

As stated in the methodology section, the estimate for this variable was based on calculating the route line length that does not fall within the known road reserve boundaries. This was considered the most representative figure Energex could produce based on the available information.

There are two opposing situations that may affect the accuracy of this estimate:

1) Line length may be accessible by a standard vehicle but is not on a road reserve (e.g. across open paddocks off the road reserve); and

2) Line length may be within a road reserve but may not be accessible by a standard vehicle (e.g. line that falls in a section of undeveloped road reserve).

Given the lack of data held by Energex systems the effects of each these situations on the estimate are unknown, and may or may not have a balancing effect on the figure reported.

3.7.7 Route Line Length and Density

The AER requires Energex to provide the following information relating to route line length and density:

- **DOEF0301 - Route Line length (RIN Table 3.7.3)**
- **DOEF0101 - Customer density (RIN Table 3.7.1)**
- **DOEF0102 - Energy density (RIN Table 3.7.1)**
- **DOEF0103 - Demand density (RIN Table 3.7.1)**

These variables are a part of Regulatory 3.7 – Operating Environment Factors.

Variable DOEF0102 (Energy density) is Estimated Information.

All other information is Actual Information.

3.7.7.1 Consistency with EB RIN Requirements

Table 3.7.13 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3.7.13 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must input the route Line Length of lines for DNSP's network.	Demonstrated in section 3.7.7.3.2 (Approach)
Line Length is based on the distance between line segments and does not include vertical components such as line sag. The route Line Length does not necessarily equate to the circuit length as the circuit length may include multiple circuits.	Demonstrated in section 3.7.7.3.1 (Assumptions)
Customer density is the total number of customers divided by the route Line Length of the network.	Demonstrated in section 3.7.7.3.2 (Approach)
Demand Density is the kVA non-coincident Maximum Demand (at zone substation level) divided by the total number of customers of the network	Demonstrated in Energy And Demand Densities
Energex must input a variable code for each weather station (for example, DEF03001 for the first weather station). Energex must add (or remove) rows from the Weather Stations table such that all weather stations within its network will be included.	Rows have been added to the Weather Stations Regulatory Template 3.7.4 and appropriately coded.

Requirements (instructions and definitions)	Consistency with requirements
Energex must input the weather station number, post code, suburb/locality for all weather stations in its service area.	This information is no longer contained within RIN Template 3.7. Energex has, instead, provided this information within this BoP - refer to Weather Stations

3.7.7.2 Sources

Table 3.7.14 below details the source systems used to obtain information for each of the required variables:

Table 3.7.14 – Data Sources

Variable Code	Variable	Source
DOEF0301	Route Line length	ArcGIS

3.7.7.3 Methodology

Energex has extracted figures for the distribution route line length for 2014/15 from ArcGIS.

3.7.7.3.1 Assumptions

- Route line length includes only horizontal components of line length.
- Route line length does not take into account multiple circuits within a line segment.
- Total underground circuit length, which is the aggregate of each circuit length provided at each voltage level (variables DPA0201 to DPA0206), does not include multiple circuits with each segment.

3.7.7.3.2 Approach

- Route line length was calculated within the ArcGIS software as the aggregate point to point distance of overhead line segments; plus the total underground circuit length (variable DPA02) for the relevant year.
- This approach effectively excludes vertical components of line length and does not take into account multiple circuits on the overhead network.
- To calculate customer density (DOEFO101), total customer numbers (DOPCN01, calculated in accordance with the Customer Numbers Basis of Preparation) for each year were divided by route line length.

Energy and Demand Densities

- "DOEF0102 – Energy density" was calculated by dividing the total energy delivered to customers (DOPED01) by the total number of customers (DOPCN01) from RIN Table 3.4.2. The energy delivered was multiplied by 1000 to convert the figures to MWh.
- "DOEF0103 – Demand density" was calculated by dividing the total non-coincident system annual maximum demand (DOPSD0201 from RIN Table 3.4.3.3) by the total number of customers (DOPCN01 from RIN Table 3.4.2.1) from RIN Table 3.4.2. The total non-coincident system annual maximum demand was multiplied by 1000 to convert the figures to MVA.

3.7.7.4 Estimated Information

Variable DOEF0102 (Energy density) is Estimated Information.

3.7.7.4.1 Justification for Estimated Information

- While the customer numbers are actuals rather estimated values, the energy delivered data is sourced from the PEACE Billing Software. It is quarterly billed so the data is not available for 3 to 4 months due to the meter reading processes. This means the data will not be finalised until the mid-October for a reported financial year.

3.7.7.4.2 Basis for Estimated Information

- Energex constructs a series of Monthly Energy Sales Models for different tariff groups (eg. T4000s large non-domestic customers, T8000s medium/small non-domestic customers and T8400 domestic customers).
- These typical econometric models use key drivers such as Queensland Gross State Product (GSP), the number of new customer connections and weather variables (eg. temperature and relative humidity indices). They systematically analyse the underlying driving forces and try to capture the impacts of those key drivers on energy sales in both the short and long term. It therefore, provides a powerful tool for Energex to do energy forecasts.
- If the actual monthly data is available for a part of the year (eg. actual billing data is available for July to March), this data will be added to the estimated (forecast) energy sales for the portion of the financial year that is unavailable (eg. April to June) to produce the full financial year figure. If necessary, some adjustments may also be included in estimation based on the latest available information.

3.7.7.5 Explanatory Notes

Energex considers that the inclusion of its underground network in the measurement of route line length is inappropriate in respect of its vegetation management program as this is driven entirely by the overhead network.

	2014/15
DOEF0101 Customer Density	32.429
DOEF0301 Route Line Length	43,085

Weather Stations

Weather Station ID	Post code	Suburb	Materiality
040004 Amberley	4306	Amberley	Yes
040842 Brisbane Airport	4008	Brisbane Airport	Yes
040211 Archerfield Airport	4108	Archerfield	Yes
040717 Coolangatta	4225	Coolangatta	Yes
040861 Maroochydore	4564	Marcoola	Yes