Energex
Economic Benchmarking RIN
Basis of Prepration

31 October 2019

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1.2 Compliance with EB RIN Requirements

Table 1-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Standard Control Services

Table 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 1.4 (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 2018-19 Pricing Proposal
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 schedule 8.1 (Income) of the Regulatory Reporting Statement. The values reported reconcile to rows “Distribution

	revenue' and "Jurisdictional scheme amounts' in the 'Standard Control Services' column of schedule 8.1 Income.
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 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."	Energex recognises revenues and penalties from incentive schemes.

Table 1-2 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Alternate Control Services

Table 1-2 - 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 ACS methodology section.
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).	Total revenue for ACS has been balanced to the Regulatory Accounts for 2019.
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 2019.

1.3 Sources

Table 1-3 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	$0's	PEACE/Regulatory Accounts N/A for ACS

	not a determinant		
DREV0103	Revenue from On–Peak Energy Delivery charges	$0's	PEACE/Regulatory Accounts N/A for ACS
DREV0104	Revenue from Shoulder period Energy Delivery Charges	$0's	PEACE/Regulatory Accounts N/A for ACS
DREV0105	Revenue from Off–Peak Energy Delivery charges	$0's	PEACE/Regulatory Accounts N/A for ACS
DREV0106	Revenue from controlled load customer charges	$0's	PEACE/Regulatory Accounts N/A for ACS
DREV0107	Revenue from unmetered supplies	$0's	PEACE/Regulatory Accounts N/A for ACS
DREV0108	Revenue from Contracted Maximum Demand charges	$0's	PEACE/Regulatory Accounts N/A for ACS
DREV0109	Revenue from Measured Maximum Demand charges	$0's	PEACE/Regulatory Accounts N/A for ACS
DREV0110	Revenue from metering charges	$0's	PEACE/Regulatory Accounts General ledger reports
DREV0111	Revenue from connection charges	$0's	PEACE/Regulatory Accounts

			General ledger reports
DREV0112	Revenue from public lighting charges	$0's	PEACE/Regulatory Accounts General ledger reports
DREV0113	Revenue from other Sources	$0's	PEACE/Regulatory Accounts General ledger reports
DREV01	Total revenue by chargeable quantity	$0's	PEACE/Regulatory Accounts

Table 1-4 - 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 1-5 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	2018-19 Pricing Proposal
DREV0303	F-Factor		Not applicable
DREV0304	S-Factor True up		Not applicable
DREV0305	Other		Not applicable
DREV03	Total revenue of incentive schemes	$0's	

Table 1-6, Table 1-7 and Table 1-8 below demonstrate the sources from which Energex obtained the required information:

Table 1-6 - 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 reports / general ledger reports

DREV0102	Revenue from Energy Delivery charges where time of use is not a determinant	$0's	N/A for ACS
DREV0103	Revenue from On–Peak Energy Delivery charges	$0's	N/A for ACS
DREV0104	Revenue from Shoulder period Energy Delivery Charges	$0's	N/A for ACS
DREV0105	Revenue from Off–Peak Energy Delivery charges	$0's	N/A for ACS
DREV0106	Revenue from controlled load customer charges	$0's	N/A for ACS
DREV0107	Revenue from unmetered supplies	$0's	N/A for ACS
DREV0108	Revenue from Contracted Maximum Demand charges	$0's	N/A for ACS
DREV0109	Revenue from Measured Maximum Demand charges	$0's	N/A for ACS
DREV0110	Revenue from metering charges	$0's	General ledger reports
DREV0111	Revenue from connection charges	$0's	General ledger reports
DREV0112	Revenue from public lighting charges	$0's	General ledger reports

DREV0113	Revenue from other Sources	$0's	General ledger reports
DREV01	Total revenue by chargeable quantity	$0's	Regulatory Accounts

Table 1-7 - 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	N/A for ACS
DREV0202	Revenue from non-residential customers not on demand tariffs	$0's	N/A for ACS
DREV0203	Revenue from non-residential low voltage demand tariff customers	$0's	N/A for ACS
DREV0204	Revenue from non-residential high voltage demand tariff customers	$0's	N/A for ACS
DREV0205	Revenue from unmetered supplies	$0's	General ledger reports
DREV0206	Revenue from Other Customers	$0's	General ledger reports
DREV02	Total revenue by customer class	$0's	Regulatory Accounts

Table 1-8 - 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

1.4 Methodology

Standard Control Services

Revenue data is collated by Energex in a Microsoft Excel spreadsheet in categories similar to what is required for the EB RIN. This spreadsheet is used to report on the under/over-collection of revenue from customers and is used along with groupings of revenue classifications to report and reconcile the revenue figures.

1) The following reports have been used for the 2018-19 regulatory year:

   a. FRC003A
   b. FRC003B
   c. FRC111
   d. FRC123
   e. MSR296

2) These reports are collated in the spreadsheet, 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 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 1-9 below:

Table 1-9 - Categorisations used to classify revenue transactions

Variable Code	Variable	Source
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’s 9000/9050/9070 - Controlled Load 1 (super economy)

		NTC's 9100/9150/9170 - Controlled Load 2 (economy) NTC 7300 – Smart Control
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 PEAK DEMAND EXCESS 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

Note: In 2015-16 most SAC non-demand tariffs were replicated with 'XX50' and "XX70' NTC's, and an 'XX20' series was added in 2018-19 to deal with differences in metering service charges (MSC) as follows;

- *The original XX00 NTC's are for customers subject to the full MSC*
- *The new XX20 NTC's are for customers that are subject to only operating costs*

- *The new XX50 NTC's are for customers that are NOT subject to a MSC*
- *The new XX70 NTC's are for customers that are subject to only a residual capital MSC*

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 1-10

Table 1-10 - Classification of network tariff codes to the customer types

Variable Code	Variable	Source
DREV0201	Revenue from residential Customers	8400/8420/8450/8470 - Residential Flat 8900/8920/8950/8970 - Residential TOU 7000/7050 – Residential Demand 9000/9020/9050/9070 - Controlled Load 1 (super economy) 9100/9120/9150/9170 - Controlled Load 2 (economy) 7300/7350 – Smart Control
DREV0202	Revenue from non-residential customers not on demand tariffs	8500/8520/8550/8570 - Business Flat 8800/8820/8850/8870 - Business – TOU
DREV0203	Revenue from non-residential low voltage demand tariff customers	7100/7150 - Business Demand 8100 - Demand Large 8300 - Demand Small 7200/7250- LV ToU Demand
DREV0204	Revenue from non-residential high	1000 - (> 40 GWh pa)

	voltage demand tariff customers	3000 - (>4 GWh pa) - 11kV EG 4000 - (>4 GWh pa) - 11kV Bus 4500 - (>4 GWh pa) - 11kV Line 8000 - HV Demand 7400 – 11kV ToU Demand
DREV0205	Revenue from unmetered supplies	9500 - Watchman Lights 9600 - Unmetered Supply
DREV0206	Revenue from Other Customers	-
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 2018-19 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).

ALTERNATIVE CONTROL SERVICES (ACS)

Figures for ACS revenue have been sourced from the general ledger and balanced back to the Regulatory Accounts for 2019.

All numbers are sourced from the general ledger and balance to the Regulatory Accounts submitted to the AER. The reported ACS revenue and its method of calculation from the source documentation is provided in Table 1-11:

Table 1-11 - ACS revenue figures and methodology

Variable Code	Variable	Source
DREV0101	Revenue from Fixed Customer Charges	Calculated as the sum of ACS revenue charged via fixed fees, using the similar information to that used for CA RIN BOP 4.3 Fee Based Services.
DREV0110	Revenue from metering charges	Sourced from the general ledger accounts specifically for metering as ACS. This includes: • Metering Services Charge • Meter test • Meter inspection • Reconfigure meter • Off-cycle meter read • Special Meter Reads • Meter Investigation • Upfront metering charge
DREV0111	Revenue from connection charges	Sourced from the general ledger accounts specifically for connections as ACS. This includes: • Real Estate Developments (or sub-divisions) • Small Customer Connections (SCCs) • Large Customer Connections (LCCs) • De-energisations • Re-energisations • Customer initiated supply enhancement • Customer consultation or appointment
DREV0112	Revenue from public lighting charges	Sourced from the general ledger accounts specifically for public lighting. This includes street lighting fixed charges, recoverable streetlighting construction and capital contributions revenue.
DREV0113	Revenue from other	Calculated as the balance of ACS Revenue. It is typically for Rearrangement of Network Assets,

	Sources	which are an Ancillary Service.
DREV01	Total revenue by chargeable quantity	Calculated as the sum of variables above.
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.

1.5 Assumptions

Standard Control Services (SCS)

Table Head 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
- STPIS as per the 2018-19Pricing Proposal has been fully recovered in revenues collected. The STPIS reward has been calculated based on data in the TAR formula and in accordance with advice received from the AER on 16 February 2018 , to reflect underlying performance results data has been based on STPIS reward implicitly included in revenues for pricing (i.e. s factor prior to removing prior years factor impact).

- Consistent with prior submissions and advice received by the AER on 22 September 2017, Energex has not populated the variable ‘DREV0305 Other’ for 2018-19.

Alternative Control Services

No assumptions were applied.

1.6 Estimated Information

Total Revenue reported reconciles to schedule 8.1 (Income) of the Regulatory Reporting Statement as follows; Row “Distribution revenue’ and ‘Jurisdictional scheme amounts in the ‘Standard Control Services’ column. This is consistent with the values reported in 2016-17.

1.7 Explanatory Notes

On a regular basis a review is performed to monitor accounting standard updates and new standards issued by the Australian Accounting Standards Board to assess the impact on Energex and Energy Queensland.

AASB15 *Revenue from Contracts with Customers* and AASB9 *Financial Instruments (December 2014)* were adopted from 1 July 2018, however there are no material impacts from the implementation of these standards that may impact the reported revenue figures.

The new Classification of Services applicable from this Determination period had a significant effect on ACS Revenue. The main contributors are:

- Many services have been reclassified from SCS to ACS. The most significant of these are Real Estate Developments (or sub-divisions) and other connection services.
- Some services have been reclassified from ACS to unregulated, the most significant of which is known damage.
- All metering charges, regardless of whether they’re fixed or quoted, are now reported solely as metering charges. This includes auxiliary metering services which had been reported as Revenue from Fixed Customer Charges in previous determination.
- All connection charges, regardless of whether they’re fixed or quoted, are now reported solely as connection charges. This includes re-energisations and de-energisations which had been reported as Revenue from Fixed Customer Charges in previous determination and Small Customer Connections which had been SCS in previous determination.

- All streetlighting charges, regardless of whether they're fixed or quoted, are now reported solely as streetlighting charges. This includes glare screening which had been reported as Revenue from Fixed Customer Charges in previous determination.
- Some services reported in previous determination have been replaced by services in accordance with the new CoS. Examples include:

  "Overhead Service Replacement – single phase" and "OH service replacement - multi phase" have been included under "Customer initiated supply enhancement"

  "Design specification & other sub-division activities" has been replaced with "Real Estate development inc design spec & audit"

  "After Hours provision of any fee-based service" and "Additional Crew" have been absorbed into those underlying fee-based services

2 BOP - 3.2 Operating Expenditure (Actual)

2.1 Scope of BoP

2.1.1 Table 3.2.1 Current Opex Categories and Cost Allocations

2.1.2 Table 3.2.2 - Opex Consistency - Current Cost Allocation Approach

2.2 Compliance with EB RIN Requirements

Table 2-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 2-1 - Demonstration of Compliance

Requirements	Consistency with requirements
Energex must report Opex in accordance with the categories that they reported in response to their Annual Reporting Requirements.	Energex has reported Opex in accordance with the categories reported in response to the Annual Reporting Requirements as detailed in RIN tables 3.2.1 and 3.2.2
Opex in table 3.2.1 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.	The Opex amounts in RIN table 3.2.1 have been prepared in accordance with Energex's Cost Allocation Approach and directions within the Annual Reporting Requirements. Total Opex equals that reported in the Annual Reporting RIN.
For table 3.2.2 Energex must report Opex in accordance with the AER Variables and the	Energex has reported Opex in the categories as defined in the AER EB RIN in accordance

Cost Allocation Approaches and reporting framework applied in the relevant Regulatory Years.	with its current Cost Allocation Approach. Total Opex for SCS in this table aligns with that in the Annual Reporting RIN.

2.3 Sources

Table 2-2 and Table 2-3 below demonstrate the sources from which Energex obtained the required information:

Table 2-2 Data Sources – RIN Table 3.2.1 Current Opex categories and cost allocations

Variable Code	Variable	Unit	Source
DOPEX0101-13	Individual Opex categories	$0's	Annual Reporting RIN
DOPEX01	Total Opex	$0's	Annual Reporting RIN

Table 2-3 Data Sources – RIN table 3.2.2: Opex consistency - current cost allocation approach

Variable Code	Variable	Unit	Source
DOPEX0201	Opex for network services	$0's	Annual Reporting RIN, Ellipse Project Ledger
DOPEX0202	Opex for metering	$0's	Annual Reporting RIN, Ellipse Project Ledger
DOPEX0203	Opex for connection services	$0's	Ellipse Project Ledger
DOPEX0204	Opex for public lighting	$0's	Annual Reporting RIN
DOPEX0205	Opex for amounts payable for easement levy or similar	$0's	Not applicable

	direct charges on DNSP		
DOPEX0206	Opex for transmission connection point planning	$0's	Not applicable

2.4 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.

RIN Table 3.2.1 Current Opex categories and cost allocations:

- RIN Table 3.2.1 requires Opex be stated on the basis of the current Cost Allocation Approach. The Opex amounts in RIN table 3.2.1 have been prepared in accordance with Energex's Cost Allocation Approach and directions within the Annual Reporting Requirements. Total Opex equals that reported in the Annual Reporting RIN.

RIN Table 3.2.2 Opex consistency – current cost allocation approach

- The Opex consistency table based on the current CAM (table 3.2.2) has been based on the values stated in RIN Table 3.2.1 Current Opex categories and cost allocations.

- RIN Table 3.2.1 balances to RIN Table 3.2.2 for SCS only. ACS will not balance between the two tables as RIN Table 3.2.2 does not include Ancillary Network Services which are reported in RIN Table 3.2.1.

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 minus the values for:

  - DOPEX0202 – Opex for metering

  - DOPEX0203 – Opex for connection services

  - DOPEX0204 – Opex for public lighting

DOPEX0202 – Opex for metering

- The formula used for calculating SCS Opex for Metering is stated below:

$$\begin{aligned} & \mathit{SCS\ Opex\ for\ Metering} \\ & \quad = \mathit{Data\ retrieval\ communication\ costs\ for\ network\ meters} \\ & \quad + \mathit{Meter\ data\ provision\ services\ for\ meters\ located\ at\ substation} \end{aligned}$$

— The data retrieval communication costs associated with Network meters for power quality purposes were extracted from project ledger information in Ellipse.

— Expenditure for meter data provision services for meters that are attached to Energex's network and used for network monitoring purposes, were extracted from Ellipse general ledger.

- ACS Opex for Metering – Total ACS Opex for Metering is taken directly from the Annual Reporting RIN.

DOPEX0203 – Opex for connection services

- The amount for SCS "DOPEX0203 – Opex for connection services" is extracted from project ledger information in Ellipse. This is for Opex incurred on overhead service line inspection program.

- The amount for ACS "DOPEX0203 – Opex for connection services" is taken directly from the Annual Reporting RIN.

DOPEX0204 – Opex for public lighting

- The amount for ACS "DOPEX0204 – Opex for public lighting" is taken directly from the Annual Reporting RIN.

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

- The amount for DOPEX0205 is zero as Energex does not pay any easement levies.

DOPEX0206 – Opex for transmission connection point planning

- The amount for DOPEX0206 is zero as Energex does not have any Opex attributable to Opex for transmission connection point planning.

2.5 Assumptions

No assumptions were applied.

2.6 Estimated Information

Refer to Section 3 BOP 3.2 Operating Expenditure (Estimate)

2.7 Explanatory Notes

RIN Table 3.2.1 Current Opex categories and cost allocations

The following explanations are provided in relation to RIN Table 3.2.1 Current Opex categories and cost allocations:

- Other network maintenance costs (DOPEX0106) represent maintenance costs for Public Lighting.

The following explanations are provided for the material variances for SCS:

- DOPEX0101 Inspection - Variance is attributable to a trade off in actual expenditure relative to the CPI adjusted forecast categories between Inspection/Planned and Corrective maintenance - overall 7% under CPI adjusted forecast

- DOPEX0102 Planned Maintenance – Variance is attributable to a trade off in actual expenditure relative to the CPI adjusted forecast categories between Inspection/Planned and Corrective maintenance - overall 7% under CPI adjusted forecast

- DOPEX0103 Corrective Repair - Variance is attributable to a trade off in actual expenditure relative to the CPI adjusted forecast categories between Inspection/Planned and Corrective maintenance - overall 7% under CPI adjusted forecast

- DOPEX0104 Vegetation - The underspend is due to the introduction of Energy Queensland's vegetation strategy and contract model achieving savings to CPI adjusted forecast

- DOPEX0105 Emergency response/storms – The underspend is due to increased asset resilience and improved efficiency in response to storm events
- DOPEX0107 Network Operating Costs – The overspend is due to increased demand for voltage correction works mostly attributed to solar PV penetration levels and impact on network. Additional spend driven by increased activity in network connectivity investigations resulting from a newly implemented project to improve Geographic Information System (GIS) capability and NECF compliance activities - data and connectivity corrections
- DOPEX0108 Network Billing and Other Energy Market Services (including meter reading) - The overspend for 2018-19 is a result of SCS Energy Market Services now attracting overhead ($0.5M), together with an increase in labour costs associated with CMO Systems & Support Staff for operational support ($0.5M).
- DOPEX0109 Customer Services (inc. call centre) – The underspend is due to the continual refinement and reduction of costs, including:
  - SE Customer Operations $1.7M less cost. Mainly due to implementations allocation of ACS related costs ACS PoW combined with efficiency measures.
  - Field response $0.8M less cost. This is customer demand related.
- DOPEX0110 DSM Initiatives – The underspend for 2018-19 is a result of the flow on from the 2015-16 board approved decision to reduce expenditure on DSM initiatives for the remaining regulatory period. Underspend is also attributed to labour efficiencies and lower than forecast spend on PeakSmart program, consistent with changes made to eligibility criteria, which removed incentives for small size air conditioners
- DOPEX0111 Levies - Increase in Electrical Safety Office payments
- DOPEX0112 Debt Raising - Following the transfer of ownership of Ergon and Energex from the state to Energy Queensland Limited (EQL) on the 30 June 2016, transfers of debt for both DNSPs were made in order to comply with the Government Owned Corporations Regulation 2016 (Regulation).
  - The share of the State Government debt pool held by the DNSPs prior to the formation of the group was a liability held by each DNSP. In accordance with

the Regulation, all DNSP debt (Queensland Treasury Corporation Loans) was transferred back to the Government debt pool. It was then transferred to the parent entity (EQL) at the carrying amount, such that: A share of Queensland debt is held in the EQL parent entity. Importantly, no debt raising costs were incurred by the DNSPs during 2018-19 as no debt was raised or refinanced.

- DOPEX0113 Other Operating Costs (inc. self-insurance) - The overspend in Other Operating Costs is primarily attributable to corporate restructuring costs $13.4M (redundancy payments).

Accounting Policies

On a regular basis a review is performed to monitor accounting standard updates and new standards issued by the Australian Accounting Standards Board to assess the impact on Energex and Energy Queensland.

AASB15 Revenue from Contracts with Customers and AASB9 Financial Instruments (December 2014) were adopted from 1 July 2018, however there are no material impacts from the implementation of these standards that may impact the RIN.

3 BOP 3.2. Operating Expenditure (Estimate)

3.1 Scope of BOP

3.1.1 BOP 3.2.4 - Opex for High Voltage Customers

3.2 Compliance with EB RIN Requirements

Table 3-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 3-1 Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
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).

3.3 Sources

Table 3-2 below demonstrates the sources from which Energex obtained the required information.

Table 3-2 Data Sources

Variable Code	Variable	Unit	Source
DOPEX0401	Opex for high voltage customers	$000's	Peace report and Pricing model

3.4 Methodology

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

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 2015-16 report:

1) NMIs with the following network tariff codes (NTCs) were determined as high voltage demand customers:

   a. 1000 – (> 40 GWh p

b. 3000 – (>4 GWh pa) - 11kV EG

c. 4000 – (>4 GWh pa) - 11kV Bus

d. 4500 – (>4 GWh pa) - 11kV Line

e. 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 Customer Analytics 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 maximum demand figures for 2016-17 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 44.5% Maximum demand figures extracted in steps 1 and 2 were then divided by 0.445 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.

3.5 Assumptions

No assumptions were applied.

3.6 Estimated Information

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

We have also had regard to the correspondence issued to management by the Australia Energy Regulator on 21 July 2016 and 12 August 2016 clarifying the presentation requirement of information in the Regulatory Information Notice data BOPs; in particular the requirement to present information as estimated if the Energex is unable to provide actual Information.

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

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.

3.7 Explanatory Notes

The method utilised to calculate the estimated Opex for HV Customers is viewed as the best method because it is based on observed maximum demand for the 2016-17 financial year for the 2 distinct groups of customers required to determine the estimate, these being

- Group 1 - sites where Energex manages the distribution transformer(s)
- Group 2 - sites where Energex does not manage the distribution transformer(s).

Because the installed transformer capacity for group 1 can be accurately derived from known connection asset data, the ratio of aggregated peak demand to aggregated installed transformer capacity (the ratio) has been accurately determined. Further supporting the accuracy of the method utilised is that with the group 1 cohort consisting of 391 sites, it can be considered to be a large enough sample size as to provide a high degree of statistical confidence to the ratio which is applied to the group 2 aggregated observed demand as the basis for estimating the installed capacity of this cohort.

Accounting Policies

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

4 BOP - 3.2.3 Provisions

4.1 Table 3.2.3 - Provisions

4.2 Compliance with EB RIN Requirements

Table 4-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 4-1 Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must 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 Performance (AP) RIN. However, the principles regarding provisions in previous years' RINs are still applicable. Provisions are allocated to services based on Property, Plant & Equipment (PP&E) balances, consistent with the methodology applied in previous year RINs to apportion balance sheet items among services. The provision amount attributed to SCS is based on the proportion of SCS PP&E to total PP&E. Provisions which are charged to indirect expenditure are apportioned to Opex and Capex components for the EB RIN based on the overhead allocation ratio, sourced from the supporting workings for the AR RIN.

4.3 Sources

Reporting for all provisions is based on the 2019 Financial Statements and AP RIN workings.

4.4 Methodology

Methodology for the provisions reporting is detailed below.

- Provisions are allocated to services based on PP&E balances. Allocation of opening balances is based on the closing PP&E balances of the prior regulatory year. The current regulatory year movements and the closing balances are allocated based on the closing PP&E balances of the current 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 AP RIN. This is reported as actual information since the overhead allocation to Capex and Opex is based on the AER approved CAM (Cost Allocation Method) and sourced from the General Ledger.
- The Provision for Employee Benefits is allocated to Opex and Capex based on labour deployment balances sourced from the General Ledger. Therefore it is also reported as actual information.
- Table 4-2 provides background on each of the provisions:

Table 4-2 Capex and Opex apportionment for each of the Provisions (SCS)

Variable Code	Variable	Capex and Opex Components
DOPEX0301-14A	Provision for Site Restoration	Charged to indirect expenditure and allocated to Opex and Capex through overhead allocations.
DOPEX0301-14B	Provision for Public Liability Insurance	Charged to indirect expenditure and allocated to Opex and Capex through overhead

		allocations.
DOPEX0301-14C	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 leave entitlements is the accrued leave balance per payroll records plus on-costs such as payroll tax, superannuation and workers' compensation. As discussed with the AER, on 1 July 2018, employees of the distribution network service providers Ergon Energy and Energex where transferred to Energy Queensland Limited (EQL) as the parent entity of the Energy Queensland Limited corporate group. EQL has entered into the Service agreement with Ergon Energy and Energex which effectively provides Energex and Ergon with a labour resource and this is subject to the direction and management of the DNSPs,

		although paid from EQL. Therefore, employee related provisions no longer reside with the DNSPs – they reside with EQL. Balance sheet balances were transferred to EQL on 30 June 2019. The closing balance of employee related provisions is therefore zero. The transfer to EQLD has been reflected in 'unused amounts reversed during the period – other component'. It is noted that movement in provisions is reflective of EQL employees whose payroll was processed in the Energex/Ergon ERP system. The movement in the EQL provisions (which represents employees whose payroll was processed in the EQL ERP system) has been apportioned between the two DNSPs on a 50/50 basis in line with how EQL costs were allocated to the DNSPs.
DOPEX0301-14D	Provision for Redundancy	Charged to other support cost directly, therefore 100% allocated to Opex. As noted in provisions for employee benefits, the redundancy provision has also been transferred to EQL and

		movements are reported on the same basis as noted above.
DOPEX0301-14E	Provision for Environmental Offsets	Charged to capital projects directly, therefore 100% allocated to Capex.
DOPEX0301-14F	Provision for Refund of Upfront Charges for Customer Requested (ACS) Work	Neither Opex nor Capex. This is related to revenue billings and has been reported in the EB RIN under Other Component.
DOPEX0301-14G	Provision for Overpaid Network Charges to be Refunded	Neither Opex nor Capex. This is related to revenue billings and has been reported in the EB RIN under Other Component.

4.5 Assumptions

The difference in PP&E allocation percentages between the current regulatory year and prior 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.

4.6 Estimated Information

Energex has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this BOP.

4.7 Explanatory Notes

The following explanations are provided in relation to provisions:

- Provision for Site Restoration (DOPEX0301A – DOPEX0314A) – The demolition and remedial work required on the ex-depot site at Banyo was substantially completed in previous years along with further earth works, soil testing and certifications required for compliance with environmental regulations. Finalisation of this remedial work was expected in 2018-19 but minor costs have been carried over into 2019/20. This provision also includes costs anticipated to "make-good" leased premises on expiration of property leases in the future.

- Provision for Employee Benefits (DOPEX0301C – DOPEX0314C) – Overall, the employee benefit provisions increased from the prior year. This includes the impact of additional leave balances for the 50% share of EQL employee entitlements and an increase due to the discounting of long term benefits. The balance of these provisions have been transferred to EQL as noted above but movements have been reflected within the DNSPs.
- Provision for Redundancy (DOPEX0301D – DOPEX0314D) – Significant workforce reductions continue to be carried out to satisfy stakeholder’s expectations before and since the formation of Energy Queensland Limited on 30 June 2016. The redundancy provision was utilised during the current year and is now raised at the parent EQL level as noted above.
- Provision for Refund of Upfront Charges for Customer Requested (ACS) Work (DOPEX0301F – DOPEX0314F) – This provision was raised for refunds to customers where estimated upfront charges for customer requested works were greater than actual costs incurred. No changes to this estimate have been made during 2018-19.
- Provision for Overpaid Network Charges to be Refunded (DOPEX0301G – DOPEX0314G) – Provision was raised for refunds to customers for overpaid network charges. No changes to this estimate have been made during 2018-19.

5 BOP - 3.3 Assets (RAB)

5.1.1 Table 3.3.1 - Regulatory Asset Base Values

5.1.2 Table 3.3.2 - Asset Value Roll Forward

5.1.3 Table 3.3.3 - Total Disaggregated RAB Asset Values

5.1.4 Table 3.3.4 - Asset Lives

5.2 Compliance with EB RIN Requirements

The AER requires Energex to report its Regulated Asset Base (RAB) in total figures and disaggregated into the asset categories defined in the EB RIN (Economic Benchmarking Regulatory Information Notice) BOPs. The definitions of these asset categories can be found in Table 5-9 under Section 5.7 Explanatory Notes of this document, extracted from the Definitions section of EB RIN Instructions and Definitions November 2013.

Table 5-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 5-1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must 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 values for the EB RIN based on the Roll Forward Models (RFMs) and Post Tax Revenue Models (PTRMs) from the AER's Final Decision: Energex determination 2015-16 to 2019-20, October 2015 (the Final Decision). The opening RAB values for 2015-16 have been sourced from the Final Decision models. Consistent with the requirements of Box 7 of EB RIN Instructions and Definitions, 2018-19 values have been populated with actual information (e.g. capital expenditure - capex, asset disposals - disposals) from the AR RIN

	(Annual Reporting RIN) for 2018-19. However given the change to using 'Forecast Depreciation" in the current determination as directed by the AER, SCS depreciation has been reported based on the forecast information used in the Final Decision RFM model. The SCS RFM disaggregates Energex's regulated assets into 28 asset categories. Each of these categories was allocated to one of the 10 asset categories specified for the EB RIN, the mapping of which can be found in Table 3.3.6 in the explanatory notes. This is consistent with the standard approach defined by the AER.
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.	Energex has not adopted an Optional Additional Approach.
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	All categories have been allocated to a single EB RIN RAB Asset category.

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 approach.	
Alternate Control Services (ACS) 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.	From 1 July 2015, ACS for Energex consists of public lighting, large customer connections, metering and ancillary network services. As the AER only approved a RAB for public lighting and metering services, only assets relating to these services are included and reported in the EB RIN ACS BOP, consistent with 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 Table 5-9 in the explanatory notes. Following expiry of the transitional approach to the treatment of capital contributions for Energex from 1 July 2015, capital contributions are not added to the RAB. As a result, capex is reported exclusive of capital contributions and DRAB13 (Value of Capital Contributions or Contributed Assets) in EB RIN table 3.3.3 is zero. ACS capital contributions are reported consistently with SCS.

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

- The AER has determined the closing RAB values for 2014-15 in its Final Decision; and
- 2018-19 values are based on actual information from the AR RIN, with the exception of forecast depreciation for SCS which has been determined from the SCS RFM approved in the Final Decision.

Therefore, the data ‘is not contingent on judgements and/or assumptions for which there are valid alternatives, which could lead to a materially different presentation’, as per the definition of ‘Actual Information’ in the AER’s EB RIN Instructions and Definitions.

The AER requires Energex to report asset life information in accordance with the asset categories defined in the EB RIN BOPs. The definitions of these asset categories can be found in BoP 3.3.1 Asset (RAB) Values, section 5.7 Explanatory Notes, Table 5-9.

Table 5-2 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 5-2 - 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 reported the service life of new assets in the RAB based on the RAB RFM from the AER's Final Decision: Energex determination 2015-16 to 2019-20, October 2015 (the Final Decision). This represents the estimated time during which 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 reported 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 Final 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 5.4 - Methodology).

5.3 Sources

The closing balance of the RABs for 2015-16 (opening balance 2016-17) has been sourced from the RFMs from the AER's Final Decision. For 2018-19, the inputs to the RFM have been sourced as follows:

- Actual capex and disposals – Sourced from the AR RIN;
- Depreciation - Sourced from forecast depreciation from the AER'S 2015 Final Decision RFM for SCS and actual depreciation from the RFM for ACS;
- CPI information – Sourced from the Australian Bureau of Statistics (ABS) data series A2325846C (eight capital cities from December to December), in line with the AER approach; and
- WACC – Sourced from the AER's 2015 Final Decision, updated for the return on debt component of the WACC every April in line with the AER guidance.

Table 5-3, Table 5-4, Table 5-5 below demonstrate the sources from which Energex obtained the required information.

Table 5-3 - Data Sources for EB RIN Table 3.3.1: Regulatory asset base values

Variable Code	Variable	Source
DRAB0101	Opening value	Final Decision
DRAB0102	Inflation addition	Australian Bureau of Statistics (ABS)

DRAB0103	Straight line depreciation	RFM - Forecast
DRAB0105	Actual additions (recognised in RAB)	AR RIN, ABS
DRAB0106	Disposals	AR RIN, ABS
DRAB0107	Closing value for asset value	Calculated from DRAB0101 to DRAB0106

Table 5-4 - Data Sources for EB RIN Table 3.3.2: Asset value roll forward

Variable Code	Variable	Source
DRAB0201-7	Overhead network assets less than 33 kV	Final Decision, AR RIN, ABS
DRAB0301-7	Underground network assets less than 33 kV	Final Decision, AR RIN, ABS
DRAB0401-7	Distribution substations and transformers	Final Decision, AR RIN, ABS
DRAB0501-7	Overhead network assets 33 kV and above	Final Decision, AR RIN, ABS
DRAB0601-7	Underground network assets 33 kV and above	Final Decision, AR RIN, ABS
DRAB0701-7	Zone substations and transformers	Final Decision, AR RIN, ABS
DRAB0801-7	Easements	Final Decision, AR RIN,

		ABS
DRAB0901-7	Meters	Final Decision, AR RIN, ABS
DRAB1001-7	“Other” asset items with long lives	Final Decision, AR RIN, ABS
DRAB1101-7	“Other” asset items with short lives	Final Decision, AR RIN, ABS

Table 5-5 - Data Sources for EB 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)	Final Decision, AR RIN, ABS
DRAB1202	Underground distribution assets less than 33 kV (cables, ducts etc.)	Final Decision, AR RIN, ABS
DRAB1203	Distribution substations including transformers	Final Decision, AR RIN, ABS
DRAB1204	Overhead assets 33 kV and above (wires and towers / poles etc.)	Final Decision, AR RIN, ABS
DRAB1205	Underground assets 33 kV and above (cables, ducts etc.)	Final Decision, AR RIN, ABS
DRAB1206	Zone substations	Final Decision, AR RIN, ABS

DRAB1207	Easements	Final Decision, AR RIN, ABS
DRAB1208	Meters	Final Decision, AR RIN, ABS
DRAB1209	Other assets with long lives (please specify)	Final Decision, AR RIN, ABS
DRAB1210	Other assets with short lives (please specify)	Final Decision, AR RIN, ABS
DRAB13	Value of Capital Contributions or Contributed Assets	Reported as zero, refer to rationale detailed in Table 3.3.1 Demonstration of Compliance

Asset life data has been sourced from the RFMs from the AER's Final 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 December to December) in line with the AER approach and regulatory reporting;
- Capex and disposals – Sourced from the Annual Performance (AP) RIN; and
- WACC – Sourced from the Final Decision, updated for the return on debt component of the WACC every April in line with the AER guidance.

Table 5-6 below demonstrate the sources from which Energex obtained the required information.

Table 5-6 - 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)	Final Decision, AR RIN, ABS

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

Table 5-7 - 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)	Final Decision, AR RIN, ABS
DRAB1502	Underground network assets less	Final Decision, AR RIN,

	than 33kV (cables)	ABS
DRAB1503	Distribution substations including transformers	Final Decision, AR RIN, ABS
DRAB1504	Overhead network assets 33kV and above (wires and towers / poles etc.)	Final Decision, AR RIN, ABS
DRAB1505	Underground network assets 33kV and above (cables, ducts etc.)	Final Decision, AR RIN, ABS
DRAB1506	Zone substations and transformers	Final Decision, AR RIN, ABS
DRAB1507	Meters	Final Decision, AR RIN, ABS
DRAB1508	“Other” assets with long lives	Final Decision, AR RIN, ABS
DRAB1509	“Other” assets with short lives	Final Decision, AR RIN, ABS

5.4 Methodology

Asset Value

- Energex has derived the SCS RAB values for EB RIN BOP 3.3 by rolling forward the approved RFM from the AER’s Final Decision, and updating for actual 2018-19 information from the AR RIN (capex and disposals), actual CPI, updated WACC and forecast depreciation. Each RAB asset category in the RFM has been rolled up into the EB RIN asset categories using the mapping provided in Table 3.3.6.

- A RFM for Network Services (NS) was constructed from the RFM for SCS using historical RAB values, actual capex, actual disposals and actual CPI and forecast depreciation that has been adjusted to remove connection assets values.

- A RFM for ACS was constructed from the Public Lighting and Metering RFMs from the AER's Final Decision, updated to include the actual capex, disposals, CPI and depreciation and updated WACC for 2018-19.

Standard Control Services

1) The RFM was based on the Final Decision. The RFM starts with the closing RAB values for the 2015-16 regulatory year and includes these values as the Opening Asset Value.

2) Data for 2018-19 was sourced from the AR RIN and depreciation from the Final Decision RFM. Consistent with the Final Decision RFM, total capitalised provision movement has been deducted from the actual capex of each asset category proportionately.

   CPI was obtained from the ABS.

   With the expiry of Energex's transitional approach from 1 July 2015, capital contributions are excluded from the RAB. As a result, capital contributions have been excluded from capex in the input sheet of the RAB RFM and the variable DRAB13 is reported as nil.

3) Using the input values in step 2) above, the RFM calculates the following for each asset category for regulatory year 2019:[1]

   a. Nominal Opening Regulated Asset Base (equals 2016 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 Forecast Straight-line Depreciation
      Extracted from the Final Decision RFM.
   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 values calculated in step 3) then form the variables stated in EB RIN tables 3.3.1, 3.3.2 and 3.3.3. Table 3.3.1 contains the aggregated RAB values, Table 3.3.2 disaggregates these values into each asset category specified in the EB RIN and

[1] 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".

Table 3.3.3 contains the yearly average RAB value of the disaggregated asset categories.

EB RIN Table 3.3.1 - Regulatory Asset Base Values

Aggregated RAB values are as set out in Table 5-8:

Table 5-8 - Aggregated RAB values EB RIN Table 3.3.2 - Asset Value Roll Forward

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 Forecast 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)

EB 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 5.7 Explanatory Notes, Table 5-9.

EB RIN Table 3.3.3 – Total disaggregated RAB asset values

EB 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.[2]

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

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

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”.

From 1 July 2015, Energex has set up General Ledger activities in Ellipse to specifically report capital expenditure (capex) relating to connection services, in addition to ACS public lighting, connection, metering and ancillary network services. Capex relating to NS can then be derived by deducting connection services capex from the total SCS capex and mapped to the asset categories required by the EB RIN. This has enabled the RAB data for each of the NS EB RIN asset categories to be reported as actuals from 2016.

The NS RFM is identical to SCS in its construction and calculation; however the inputs are adjusted for the following:

- The RFM opening values were adjusted to include only those values relating to NS and adjusted for any change in service classification in the 2015 Final Decision.
- The capex relating to connection assets was deducted from the capex in the SCS RFM to derive the NS values. The capitalised provision movement allocated to each asset category for SCS has been allocated to NS based on the proportion of NS capex to SCS capex for that asset category.
- The asset categories “Low voltage services” and “Load control and network metering devices” have previously been treated as connection services and therefore wholly excluded from the NS EB RIN. The reclassification of metering services from 1 July 2015 has removed a large part of this asset base from SCS; however there are some residual metering services associated with network, high voltage meters and load control services. These are included in the NS RFM from 2016. The capex on low voltage services as derived from the capex report is also included in the NS RFM from 2016 as the AER’s EB RIN Instructions and Definitions specify that works on connections assets subsequent to their installation should be reported as network services and this capex relates to replacement of faulty asset components.

- The value of disposals for NS is taken to be the same as the SCS asset categories as connection asset disposals are not considered material.

Alternative Control Services

- From 1 July 2015, Energex's ACS includes public lighting, connection, metering and ancillary network services. As the AER only approved a RAB for public lighting and metering services, only assets relating to these services are included and reported in the EB RIN Assets BOP for ACS, consistent with the EB RIN Instructions and Definitions.

- CPI and WACC are based on those used for the SCS.

- Capex for ACS was sourced directly from the AR RIN and/or supporting workings.

Asset Lives

Energex has calculated the expected service life of new assets and the residual service life of assets based on the RFMs from the Final Decision. These RFMs were updated for the 2019 actual information (capex and asset disposals) from the AR RIN.

Standard Control Services

1) The estimated service life of new assets was calculated using the standard service life published in the Final Decision RFM. This service life was applied to 2019. The asset life categories in the 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 2019 closing RAB value. For the mapping of the Final Decision RFM asset categories to the EB RIN categories refer to BoP 3.3.1 Asset (RAB) Values, Section 5.7 Explanatory Notes, Table 5-9.

2) The residual service life of RAB assets was calculated using the Asset Life RFM BOP used for the Final Decision using estimated standard lives for additions and residual lives of existing assets. The calculations were extended to 2019 to complete the EB RIN data requirements. This BOP relies on information calculated in the extended RAB RFM for SCS, ACS and NS, as detailed in Basis of Preparation for Asset (RAB) Values. The extended Asset Life RFM BOP extracts the following information found in the RAB RFM for each asset category and regulatory year:
    a. Standard Asset Life;
    b. Opening RAB Value (2016);

c. Opening RAB Residual Asset Life (2016);

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 3.3.6.

Network Services

5) NS are defined as a subset of SCS. A separate RAB RFM has been developed in relation to NS as described in Basis of Preparation for Asset (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. Connection assets). For details of the construction of the NS RAB RFM refer to Basis of Preparation for Asset (RAB) Values.

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

Alternative Control Services

6) From 1 July 2015, Energex's ACS includes public lighting, connection, metering and ancillary network services. As the AER only developed a RAB for public lighting and metering services based on the limited building block approach, only these services are included in the RFM, consistent with the EB RIN Instructions and Definitions.

   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 Asset (RAB) Values.

5.5 Assumptions

Asset Values

No assumptions were made.

Asset Lives

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

5.6 Estimated Information

Energex has provided 'Actual Information' (as per the AER's defined term) in relation to all variables contained in this BOP.

5.7 Explanatory Notes

EB RIN Asset Category Definitions and Mapping

Table 5-9 - 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	Overhead Distribution Lines Low Voltage Services

	include poles, pole-top structures and overhead conductors. This does not include pole top substations and transformers.	
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	Underground Sub-Transmission Cables

	other assets used to connect the underground network to the overhead system. This does not include underground substations and transformers.	
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 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.	Easements (System)
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:	Communications Pilot Wires Street Lighting

<table>
<tr><td></td><td>Overhead Distribution Assets (Wires And Poles)
Underground Distribution Assets (Cables)
Distribution Substations Including Transformers
Zone Substations And Transformers
Easements
Meters</td><td>Other Equipment
Control Centre - SCADA
Buildings
Land
Equity Raising Costs</td></tr>
<tr><td>Other assets with short lives</td><td>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</td><td>Communications
IT Systems
Office Equipment & Furniture
Motor Vehicles
Plant & Equipment
Research and Development</td></tr>
</table>

Accounting Policies

On a regular basis, a review is performed to monitor accounting standard updates and new standards issued by the Australian Accounting Standards Board to assess the impact on Energex. Changes are advised to the Audit Committee and implemented where required and the associated Energex accounting policies are updated accordingly.

There are no material impacts from changes in accounting standards for the 2019 financial year, and subsequently no accounting policy changes that may impact the RIN.

6 BOP - 3.4 Operational Data (Estimated)

6.1 Scope of BOP

6.1.1 Table 3.4.1 - Energy Delivery

6.2 Compliance with EB RIN Requirements

Table 6-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 6-1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
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. Data for DOPED0206 are actuals, but for DOPED0201 ~ 0205, DOPED0205 and DOPED01, they are estimation.
Energex is required to report energy received from Non-residential Embedded Generation by	Only solar generation has been reported in DOPED0405 and they are estimation. Other

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)	data in table 3.4.1.3 are actuals.
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[1]. Data for DOPED0504 ~ 0505 are actuals but are estimation for DOPED0501 ~ 0503.

6.3 Sources

Table 6-2, Table 6-3, Table 6-4 and Table 6-5 specify the sources from which Energex obtained the required information.

Table 6-2 - Data Sources: RIN Table 3.4.1: Energy delivery – total energy delivered

Variable Code	Variable	Unit	Source
DOPED01	Total energy delivered	GWh	PEACE

Table 6-3 - 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 NLF
DOPED0203	Energy Delivery at Shoulder times	GWh	-

DOPED0204	Energy Delivery at Off-peak times	GWh	PEACE and NLF
DOPED0205	Controlled load energy deliveries	GWh	PEACE

Table 6-4 – 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
DOPED0405	Energy into DNSP network at On-peak times from residential embedded generation	GWh	PEACE

Table 6-5 - 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
DOPED0503	Non-residential low voltage demand tariff customers energy deliveries	GWh	PEACE

6.4 Methodology

Annual energy data in the Energex Network can be classified into two categories, based on both the energy flow features and the 2018-19 Economic Benchmarking RIN requirement:

- Energy Delivered (i.e. kWh conveyed by Energex to end users)
- Energy Purchased (i.e.; 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.

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 6-6 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 6-6 - Method for calculating delivery by chargeable quantity

Variable Code	Variable	Source
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 (i.e.; the following NTCs: 1000, 3000, 4000, 4500, 7000, 7050, 7100, 7150, 7400, 8000, 8100, 8300, 8800, 8820, 8850, 8870, 8900, 8920, 8950 and 8970) sourced from PEACE system to calculate the total on-peak-time energy delivery. Note: Energex introduced the two new time-of-use (ToU) tariff groups in July 2018: 7200 and 7250. The customers which fall into these two groups mainly come from the existing 8100 and 8300 groups rather than new connections. Based on the monthly data for these two groups, the energy delivered at on-peak times continued to decrease and went close to zero in the late months of 2018-19. In the meantime, the energy delivered at off peak times continued to increase over the same period. Therefore, while the total energy delivered (peak and off-peak combined) was consistent throughout 2018-19, the peak vs off peak energy split

		ratios significantly changed during 2018-19. This is reflected in items DOPED0202 and DOPED0204 of the table 3.4.1.1 in the 2018-19 EB RIN. Energex is still investigating this at the time of the RIN submission, and will notify the AER as soon as possible if a resubmission of this data is required.
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 (i.e.; the following NTCs: 1000, 3000, 4000, 4500, 7000, 7050, 7100, 7150, 7400, 8000, 8100, 8300, 8800, 8820, 8850, 8870, 8900, 8920, 8950 and 8970) sourced from PEACE system to calculate the total off-peak-time energy delivery. Note: in regards to the energy delivered in the off-peak times for the newly introduced 7200 and 7250 groups, please see the

		explanation in DOPED0202 of this table.
DOPED0205	Controlled load energy deliveries	Sum of energy delivered to controlled load customers, calculated as the sum of NTCs 7300, 9000, 9020, 9050, 9070, 9100, 9120, 9150 and 9170.

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 6-7:

Table 6-7 - Method for calculating RIN Table 3.4.1.3 Energy – received into DNSP system from embedded generation by time of receipt

Variable Code	Variable	Source
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.

RIN table 3.4.1.4: Energy grouping – customer type or class

Data in this table was sourced from the Energex billing system (PEACE) and was detailed in Table 6-8:

Table 6-8 - Method for calculating RIN Table 3.4.1.4 Energy grouping: customer type or class

Variable Code	Variable	Source

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: 7000, 7300, 8400, 8420, 8450, 8470, 8900, 8920, 8950, 8970, 9000, 9020, 9050, 9070, 9100, 9120, 9150 and 9170. The residual value of energy delivered if it has (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, 8520, 8550, 8570, 8800, 8820, 8850 and 8870. 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 7100, 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.

6.5 Assumptions

Energy Delivered

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.

6.6 Estimated Information

Table 3.4.1 Energy Delivered

- All energy delivered which includes variables DOPED01, DOPED0201, DOPED0205, DOPED0501 and DOPED0502 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 (i.e. DOPED0405 in RIN table 3.4.1.3).

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.

Basis for Estimation

- Energex constructs a series of Monthly Energy Sales Models for different tariff groups (e.g. T4000s large non-domestic customers, T8000s medium/small non-domestic customers and domestic non-controlled customers which combine with T7000, T8400, T8420, T8450, T8470, T8900, T8920, T8950 and T8970 network tariff groups).

- These typical econometric models use key drivers such as Queensland Gross State Product (GSP), the number of new customer connections and weather variables (e.g.; 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.

6.7 Explanatory Notes

Not applicable.

7 BOP 3.4 – Operational Data (Actual)

7.1 Scope of BOP

7.1.1 Table 3.4.1 - Energy Delivery

7.1.2 Table 3.4.2 - Customer Numbers

7.1.3 Table 3.4.3 - System Demand

7.2 Compliance with EB RIN Requirements

Table 3.4.1 Energy delivered

Table 7-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 7-1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
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. Data for DOPED0206 are actuals, but for DOPED0201 ~ 0205, DOPED0205 and DOPED01, they are estimation.

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. All data in this group (i.e.; table 3.4.1.2) are actuals.
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 and it was estimated. Other data in table 3.4.1.3 was actuals.
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[1]. Data for DOPED0504 ~ 0505 are actuals but are estimation for DOPED0501 ~ 0503.

Table 3.4.2 Customer Numbers

Table 7-2 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 7-2 - 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.	Energex has calculated all customer

Both energised and de-energised NMIs must be counted. Extinct NMIs must not be counted.	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.

Table 3.4.3 System Demand

Table 7-3 specifies how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 7-3 - 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 7.4 (Methodology).
Energex must provide inputs for these cells if it has calculated historical Weather Adjusted Maximum Demand.	Demonstrated in section 7.4 (Methodology).
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 7.4 (Methodology).
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 7.4 (Methodology).

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 7.4 (Methodology).
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 7.4 (Methodology).
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 7.4 (Methodology). Energex does not include Embedded Generation in its calculation of Maximum Demand.
Coincident Weather Adjusted System Annual Maximum 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.	Demonstrated in section 7.4 (Methodology).
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 7.4 (Methodology).

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 7.4 (Methodology). 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 7.4 (Methodology).
Non–Coincident Weather Adjusted System Annual Maximum Demand 50% POE is the	Demonstrated in section 7.4

summation of 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.	(Methodology).
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 7.4 (Methodology).

Table 3.4.3.5 Power factor conversion between MVA and MW

Table 7-4 specifies how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 7-4 - 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 7.4 (Methodology).
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	Demonstrated in section 7.4 (Methodology).

MW divided by the total MVA.	
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 7.4 (Methodology).

Table 3.4.3.6 & 3.4.3.7 demand supplied (for customers charged on this basis)

Table 7-5 specifies how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 7-5 - 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 7.4 (Methodology).
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 7.4 (Methodology).
Energex is only required to complete RIN table 3.4.3.7 if it charges customers for demand supplied. If Energex does not	Demonstrated in section 7.4 (Methodology).

charge customers on this basis then Energex must enter '0'.	
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 7.4 (Methodology).
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.

7.3 Sources

Table 3.4.1 Energy delivery

Table 7-6, Table 7-7, Table 7-8 and Table 7-9 specifies the sources from which Energex obtained the required information.

Table 7-6 - Data Sources: RIN Table 3.4.1.1: Energy grouping - delivery by chargeable quantity

Variable Code	Variable	Unit	Source
DOPED0206	Energy Delivery to unmetered supplies	GWh	PEACE

Table 7-7 - 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 7-8 - 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	-
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 7-9 - Data Sources: RIN Table 3.4.1.4 Energy grouping – customer type or class

Variable Code	Variable	Unit	Source
DOPED0504	Non-residential high voltage demand tariff customers energy	GWh	PEACE and NLF

	deliveries		
DOPED0505	Other Customer Class Energy Deliveries	GWh	PEACE

Table 3.4.2 Customer numbers

Table 7-10 specifies the sources from which Energex obtained the required information.

Table 7-10 - 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	number	Not Applicable

	Numbers		
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 PoN system as detailed in Table 7-11 below:

Table 7-11 - Data sources for customers by network location

Variable Code	Variable	Unit	Source
DOPCN0201	Customers on CBD network	number	PoN
DOPCN0202	Customers on Urban network	number	PoN
DOPCN0203	Customers on Short rural network	number	PoN
DOPCN0204	Customers on Long rural network	number	Not Applicable
DOPCN02	Total customer numbers	number	PoN

Table 3.4.3 - System Demand

Annual System Maximum Demand

- The SIFT database 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 7-12, Table 7-13, Table 7-14 and Table 7-15 specifies the sources for additional responses to variables relating to annual system maximum demand:

Table 7-12 - 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 7-13 - 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 7-14 - Data sources for the annual system maximum demand characteristics at the transmission connection point – MW 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 7-15 - 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

Table 3.4.3.5 Power factor conversion between MVA and MW

Table 7-16 specifies the sources from which Energex obtained the required information.

Table 7-16 - Demonstration of Compliance

Variable Code	Variable	Unit	Source
DOPSD0301	Average overall network power factor conversion between MVA and MW	Factor	SIFT/Metering data from Network Load Forecasting (NLF) Database
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

Table 3.4.3.6 & 3.4.3.7 Demand Supplied (for customers charged on this basis)

Table 7-17 and Table 7-18 specifies the sources from which Energex obtained the required information.

Table 7-17 - Data source for demand supplied (for customers charged on this basis)

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

Table 7-18 - Data source for demand supplied (for customers charged on this basis)

Variable Code	Variable	Source
DOPSD0403	Summated Chargeable Contracted Maximum Demand	PEACE
DOPSD0404	Summated Chargeable Measured Maximum Demand	PEACE

7.4 Methodology

Table 3.4.1 Energy delivered

Annual energy data in the Energex Network can be classified into two categories, based on both the energy flow features and the 2018-19 Economic Benchmarking RIN requirement:

- Energy Delivered (i.e. kWh conveyed by Energex to end users)
- Energy Purchased (i.e.; 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.

RIN table 3.4.1.1: Energy grouping – delivery by chargeable quantity

The calculation of each line item is summarised in the Table 7-19 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 7-19 - Method for calculating delivery by chargeable quantity

Variable Code	Variable	Source
DOPED0206	Energy Delivery to unmetered supplies	Sum of street lighting only based on NTC 9600. The other unmetered energy delivery accounts for very small amount of the total energy delivered. It is historically treated as energy losses so it is not included in this category.

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) and was detailed below:

Table 7-20 - Method for calculating RIN Table 3.4.1.2 Energy – received from TNSP and other DNSPs by time of receipt

Variable Code	Variable	Source
DOPED0301	Energy into DNSP network at On-peak	Sum of all energy received to Energex connection points between

	times	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 (e.g.; it was positive 4.295 GWh for the 2018-19 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 7-21:

Table 7-21 - Method for calculating RIN Table 3.4.1.3 Energy – received into DNSP system from embedded generation by time of receipt

Variable Code	Variable	Source

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-residential embedded generation	Not applicable.
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.
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) and was detailed below:

Table 7-22 - Method for calculating RIN Table 3.4.1.4 Energy grouping: customer type or class

Variable Code	Variable	Source
DOPED0504	Non-residential high voltage demand tariff customers energy deliveries	Calculated as the sum of NTCs up to 8000 (excluding 7000 and 7100). 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.

Table 3.4.2 Customer Numbers

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 PowerOn (PoN) systems respectively. The total customer numbers in these two systems do not match and this is expected and explained in 3.4.2.5 Explanatory Notes.

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

Network Tariff codes have been used to split the customers across DOPCN0102, DOPCN0103, DOPCN0104. Refer to Table 9.4 – Network Tariffs to assign Customer Types to see exactly how it was done.

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) The Network Tariff Code was used to determine the customer voltage. This is considered the most reliable way to break the customers up into the voltages requested.
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 PoN system. 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. De-en customers are included. UMS are excluded from these totals and have not been added in.

3) Where the customer's distribution transformer (Network Attachment Point (NAP)) or Feeder is not known, the customer is not counted in the totals in PoN. Therefore, these missing customers have been added to each total using proportional allocation (using the existing percentages of customers against each feeder category).

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

Table 3.4.3 System Demand

Annual System Maximum Demand

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, Sat, Sun, Public Holidays, Xmas Shutdown, Fridays +c)

4) Each zone substation and connection point's load data is correlated with each of the five weather stations, the weather station with the highest statistical best fit is the weather station chosen for the modelling.

5) 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 Connection Point was aggregated to find for total non-coincident peak;
- The Connection Point coincident MW and MVA values were calculated from as recorded system raw demand.
- Energex recently developed a weather adjustment process similar to the AEMO recommended approach for Connection Points.
- 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 are not only based on peaks from either the summer or the winter, but there are also differences in the methodology of temperature correction, with the POE methodology used at the Energex System level incorporating more explanatory variables - like economic and demographic drivers.
- The non-coincident zone substation summated demands are from any half hour, and therefore diversity of load peaks & losses need to be accounted for in any comparison between aggregated zone substation and connection point demands.

Table 3.4.3.5 Power factor conversion between MW and MVA

The methodology and justification for the low voltage distribution line power factor conversion is outlined below in 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 NLF;
- 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. While only part of the load supplied by Somerset is SWER, the substation's power factor is considered to be a reliable predictor of its SWER component, due to the similarities of the load supplied;
- 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 based on the average power factor across a sample of 6451+ distribution transformers randomly scattered across the Energex network. The power factor calculated is considered to be a reliable estimate as a sample of that size with a 95% confidence interval yields a band of only + / - 1.14%.

Table 3.4.3.6 & 3.4.3.7 Demand Supplied (for customers charged on this basis)

From the 2017-18 financial year, a different methodology has been utilised. Data has been sourced directly from the network billing system and Network Use of System charges were used to differentiate between Contracted and Actual Demand as per the table below.

Charge Code	Demand Type
NDADC	KWh Actual Demand

NDKVACC	kVA Contract Demand
NDKVAADC	kVA Actual Demand

In recent year's individual NMI's or premises were recorded in either KW or kVA and this data was used to extrapolate its corresponding measure using a power factor of 0.9. i.e. If the premise was charged based on kVA, it was converted to KW and counted towards both table 3.4.3.6 and 3.4.3.7. The new methodology reports only on the metric for which the customer is charged. On an individual customer basis, the highest monthly actual demand charge is used unless the contracted demand is

7.5 Assumptions

Table 3.4.1 Energy Delivered

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.

Table 3.4.3 System Demand

Annual System Maximum Demand

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 summer period is November, December, January, February and March;
- Refer to CA RIN BoP 5.4.1 Maximum Demand and Utilisation Spatial section 22.5 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 17.0 degrees Celsius during the winter period was disregarded;
- Any day where the average temperature at Amberley was below 24.5 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 the best fit across 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 duration of the winter period is June, July and August;
- The duration of the summer period is November, December, January, February and March;
- The temperature is based on the average for each day;
- Any day where the average temperature at Amberley was above 17.0 degrees Celsius during the winter period was disregarded;
- Any day where the average temperature at Amberley was below 24.5 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.

7.6 Estimated Information

Refer to Section 6 BOP – 3.4 Operational Data (Estimated)

7.7 Explanatory Notes

Table 3.4.2 Customer Numbers

Reconciliation of total customer figures between 3.4.2.1 and 3.4.2.2

PoN feeds a corporate Energex EPM report and has done since 1/7/2015 (Customers by Feeder Category). This is considered a more appropriate solution to report customer numbers by feeder category than NFM.

Where the customer's distribution transformer (or Network Attachment Point (NAP)) or feeder category is not known, the customer is not counted in the totals in PoN as they cannot be allocated to a feeder (and therefore a feeder category).

Therefore, these missing customers have been added to each total (each feeder category) using proportional allocation (using the existing percentages of customers against each feeder category).

Table 7-23 - Network Tariffs used to assign Customer Types

Network Tariff Code	Customer Type
1000	HV Demand
3000	HV Demand
4500	HV Demand
4000	HV Demand
8000	HV Demand
7400	HV Demand
7100	LV Demand - NonRes

8300	LV Demand - NonRes
8100	LV Demand - NonRes
8800	LV Demand - NonRes Non Demand
8500	LV Demand - NonRes Non Demand
8850	LV Demand - NonRes Non Demand
8870	LV Demand - NonRes Non Demand
8550	LV Demand - NonRes Non Demand
8570	LV Demand - NonRes Non Demand
All other NTCs	Residential

8 BOP - 3.5 Physical Assets (Estimated)

8.1.1 Table 3.5.1 - Network Capacities

8.1.2 Table 3.5.2 - Transformer Capacities

8.2 Compliance with EB RIN Requirements

Table 8-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 8-1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
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 8.4 (Methodology).
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 BOP 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 8.4 (Methodology).

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 8.4 (Methodology).

Table 8-2 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 8-2 - 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 8.4 (Methodology).
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	Demonstrated in section 8.4 (Methodology).

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.	
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 8.4 (Methodology).

Table 8-3 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 8.4 (Methodology).
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 8.4 (Methodology).
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 8.4 (Methodology).

Table 8-4 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 8-4 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex must report total installed Distribution Transformer Capacity.	Demonstrated in section 8.4 (Methodology).
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	Demonstrated in section 8.4 (Methodology).

intermediate transformation capacity (e.g. 132 kV or 66 kV to the 22 kV or 11 kV distribution level).	
The capacity measure is the normal nameplate continuous capacity / rating (including forced cooling and other factors used to improve capacity).	Demonstrated in section 8.4 (Methodology).
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 8.4 (Methodology).
The transformer capacity owned by Energex is to be reported using the nameplate continuous rating including forced cooling.	Demonstrated in section 8.4 (Methodology). The data does not include forced cooling as it is not applicable for Energex.
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 8.4 (Methodology).
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	Demonstrated in section 8.4 (Methodology).

for delivery capacity within the high voltage customers.	
Energex must report the total capacity of spare transformers owned by Energex but not currently in use.	Demonstrated in section 8.4 (Methodology).
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 8.4 (Methodology).
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 8.4 (Methodology).

8.3 Sources

Table 8-5 below demonstrate the sources from which Energex obtained the required information.

Table 8-5 – Data Sources

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

Circuit capacity - 11kV and SWER

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 8-6 and Table 8-7:

Table 8-6 - 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 8-7 - 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.

The input data for the distribution transformer total installed capacity variables were extracted from the NFM database, PEACE and Ellipse. NFM and Ellipse information is then stored in DMA for reporting purposes. The information for Distribution Transformer Capacity owned by High Voltage Customers was retrieved directly from Peace.

Table 8-8 demonstrates the sources from which Energex obtained the required information.

Table 8-8 - Data Sources

Variable Code	Variable	Source
DPA0502	Distribution Transformer Capacity owned by High Voltage Customers	PEACE

- 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.

8.4 Methodology

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 2016 (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

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; and
- 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

Distribution Transformer Capacity owned by High Voltage Customers

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 demands; with each customers capacity estimated to be the standard transformer capacity greater than their historical peak demands and
- Where capacities were available these values were used.

8.5 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.

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.
- All of the results are based on feeder's the energised operating voltage.

Distribution Transformer Capacity owned by High Voltage Customers

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

- Transformer capacity for each high voltage customer is estimated from their individual annual peak demands recorded between 2006 and 2018.

8.6 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.

Circuit Capacity - 11kV and SWER

For the 11kV 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 provider operational ratings. Furthermore, these ratings are not separated into overhead or underground components.

Distribution Transformer Capacity owned by High Voltage Customers

Justification

Energex is not able to directly find out what the capacity of each transformer is, as the transformers are owned by customers and located on the customer's sites.

Basis for Estimation

High voltage transformers are available in standard sizes. Customers tend to size their transformers to be slightly greater than their expected peak loads.

8.7 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 2016 regulatory year. On 21 July 2016, the AER advised that information in these tables is not required to be reported as Actual Information as the average values are inherently estimated.

Circuit capacity - 11kV and SWER

Rating Conversion

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

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

9 BOP 3.5 Physical Assets (Actual)

9.1 Scope of BOP

9.1.1 Table 3.5.1 - Network Capacities

9.1.2 Table 3.5.2 - Transformer Capacities

9.1.3 Table 3.5.3 - Public Lighting

9.2 Compliance with EB RIN Requirements

Circuit Length

Table 9-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 9-1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energex is required to report against the capacity variables for the whole network.	Demonstrated in section 9.4 (Methodology).
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 9.4 (Methodology). 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 9.4 (Methodology).
Specify the voltage for each 'other' voltage	Energex does not have any other voltage levels to those specified in the AER's RIN

level, where applicable.	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 9.4 (Methodology).

Circuit Capacity

Table 9-2 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 9-2 - 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 9.4 (Methodology).
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 BOP 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 section 9.4 (Methodology).
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 9.4 (Methodology).

Circuit capacity - 11kV and SWER

Table 9-3 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 9-3 - 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 9.4 (Methodology).

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 BOP itself it has not been addressed in the methodology. That is, this refers to Maximum Demand when the remainder of the report relates 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 section 9.4 (Methodology).
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 9.4 (Methodology).

Zone substations transformer capacity

Table 9-4 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 9-4 - Demonstration of Compliance

Requirements (instructions and definitions)	**Consistency with requirements**
Energex must report total installed	Demonstrated in section 9.4 (Methodology).

Distribution Transformer Capacity.	
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 9.4 (Methodology).
The capacity measure is the normal nameplate continuous capacity / rating (including forced cooling and other factors used to improve capacity).	Demonstrated in section 9.4 (Methodology).
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 9.4 (Methodology).
The transformer capacity owned by Energex is to be reported using the nameplate continuous rating including forced cooling.	Demonstrated in section 9.4 (Methodology). The data does not include forced cooling as it is not applicable for Energex.
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 9.4 (Methodology).
Where the transformer capacity owned by customers connected at high voltage is not	Demonstrated in section 9.4 (Methodology).

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.	
Energex must report the total capacity of spare transformers owned by Energex but not currently in use.	Demonstrated in section 9.4 (Methodology).
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 9.4 (Methodology).
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 9.4 (Methodology).

Zone substations transformer capacity

Table 9-5 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 9-5 - 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 9.4 (Methodology).
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 9.4 (Methodology).
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 9.4 (Methodology).
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 11 kV where there will be a second step transformation before reaching the distribution	Demonstrated in section 9.4 (Methodology).

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 9.4 (Methodology).
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 9.4 (Methodology).
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	Demonstrated in section 9.4 (Methodology).

voltage (for example DPA0604 will be the sum of DPA0601, DPA0602, DPA0603 and DPA0605.)	
The total Cold Spare Capacity included in total zone substation transformer capacity is to be provided.	Demonstrated in section 9.4 (Methodology).
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 9.4 (Methodology).
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 9.4 (Methodology).

Public Lighting

Table 9-6 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 9-6 - 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 9.4 (Methodology).
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 9.4 (Methodology).
Only poles that are used exclusively for public lighting are to be included in the data.	Demonstrated in section 9.4 (Methodology).

9.3 Sources

Circuit Length

The circuit lengths at each voltage level were extracted from the Network Facilities Management (NFM) database. This is outlined in Table 9-7 and Table 9-8 below:

Table 9-7 - Data Source for overhead network length of circuit at each voltage

Variable Code	Variable	Source
DPA0101	Overhead low voltage distribution	DMA
DPA0102	Overhead 2.2 kV	Not Applicable
DPA0103	Overhead 6.6 kV	Not Applicable
DPA0104	Overhead 7.6 kV	Not Applicable
DPA0105	Overhead 11 kV	DMA

DPA0106	Overhead SWER	DMA
DPA0107	Overhead 22 kV	Not Applicable
DPA0108	Overhead 33 kV	DMA
DPA0109	Overhead 44 kV	Not Applicable
DPA0110	Overhead 66 kV	Not Applicable
DPA0111	Overhead 110 kV	DMA
DPA0112	Overhead 132 kV	DMA
DPA0113	Overhead 220 kV	Not Applicable
DPA0114	Other	Not Applicable
DPA01	Total overhead circuit km	DMA

Table 9-8 - Data Source for underground network length of circuit at each voltage

Variable Code	Variable	Source
DPA0201	Underground low voltage distribution	DMA
DPA0202	Underground 5 kV	Not Applicable
DPA0203	Underground 6.6 kV	Not Applicable
DPA0204	Underground 7.6 kV	Not Applicable
DPA0205	Underground 11 kV	DMA

DPA0206	Underground SWER	DMA
DPA0207	Underground 22 kV	Not Applicable
DPA0208	Underground 33 kV	DMA
DPA0209	Underground 66 kV	Not Applicable
DPA0210	Underground 110 kV	DMA
DPA0211	Underground 132 kV	DMA
DPA0212	Other	Not Applicable
DPA02	Total underground circuit km	DMA

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. This information is then stored in DMA.

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.

Circuit Capacity

Table 9-9 below demonstrates the sources from which Energex obtained the required information.

Table 9-9 - Data Sources

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

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 9-10 below demonstrate the sources from which Energex obtained the required information.

Table 9-10 - Data Sources

Variable Code	Variable	Source
DPA0310	Overhead 110 kV	PSS/E, DMA, DMS
DPA0311	Overhead 132 kV	PSS/E, DMA, DMS
DPA0411	Underground 110 kV	PSS/E, DMA, DMS

Distribution Transformer Total Installed Capacity

The input data for the distribution transformer total installed capacity variables were extracted from the NFM database, PEACE and Ellipse. NFM and Ellipse information is then stored in DMA for reporting purposes. The information for Distribution Transformer Capacity owned by High Voltage Customers was retrieved directly from Peace.

Table 9-11 demonstrates the sources from which Energex obtained the required information.

Table 9-11 - Data Sources

Variable Code	Variable	Source
DPA0501	Distribution Transformer Capacity owned by utility	DMA
DPA0503	Cold Spare Capacity included in DPA0501	DMA

- 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.

Zone substation transformed total installed capacity

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

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
DPA0603ï	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/DMA

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

Public Lighting

The number of public lighting poles was sourced from the NFM database. The Data is then Stored in DMA.

Table 9-12 below demonstrates the sources from which Energex obtained the required information.

Table 9-12 - Data Sources

Variable Code	Variable	Source
DPA0701	Public lighting luminaires	NFM/SLIM
DPA0702	Public lighting poles	DMA

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.

The SLIM program is a feeder system that captures inventory numbers for unmetered supply. Data entered into NFM feeds to SLIM in preparation for end of month billing.

9.4 Methodology

Circuit Length

The following approach was applied to calculate the variables:

- The data for 2018-19 was obtained by running DMA Reports. In particular the DMA Reports were run to extract data for each of the voltage levels for 2018-19. The SWER lines were separated from the 11kV overhead lines by identifying the feeders and the conductor count. The reports extracted data for the overhead and underground circuit length of each voltage level.

Circuit Capacity

The following approach is applied to calculating the values:

1) The 33kV network is modelled in Sincal. The feeder conductor types and lengths in Sincal are obtained from GIS/NFM, ‘Design’ drawings or ‘As-constructed’ drawings.

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

3) Load flow studies using the 2018-19 summer and 2018 winter forecasts were conducted to identify the highest demand season for each of the feeders. The seasonal rating of the highest utilised feeder segment is obtained and compared with the circuit breaker rating. The lower of the two ratings is used to represent the overall constrained rating of the feeder.

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

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 model.

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:

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

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

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)

The following approach is applied to calculating the values:

1) The feeder rating data for 18-19 is obtained from the DMA system. If the feeders were identified in DMS to be thermally limited by its circuit breaker, the circuit breaker rating is then used to represent the thermal limit rating of the feeder.
2) For feeders which are the limiting element (not limited by circuit breaker rating capacity) with multiple tee-off points, the rating of the entire feeder is represented by the feeder rating section of the highest utilisation. PSS/E load flow studies using 2018 summer and winter forecasts were conducted to identify the highest utilised feeder section and its seasonal maximum demand.
3) The current BOP 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 the DMA report and verified through Energex's PSS/E models and DMS system.
4) Line length data is extracted from DMA and is subsequently matched to each corresponding feeder name and rating.

5) To obtain the weighted average MVA, each feeder is then segregated into its respective voltage levels and UG and OH components based on the DMA feeder length report.

6) Each feeder length component is then multiplied by its corresponding rating and 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:

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

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

Distribution Transformer Total Installed Capacity

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

- The data was obtained by running the DMA Report for 2018-19 period;
- The data was then combined into a master document and arranged into the AER BOP 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 the Cold spare capacity included in DPA0501 (DPA0503):

- The data was obtained through the DMA 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 2019; and
- Distribution transformer capacity was extracted from the stock code description

Zone Substation Transformer Capacity

The following approach was applied to calculating the variables:

- The data was extracted from SIFT as at June 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 DMA report, generated from a database containing daily snapshots of inventory held in Ellipse;
  - Power transformer assets were extracted from the report as at 30 June 2019;

— Power transformer assets not yet logged by the warehouse as stock on hand have been included; and

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

- The approach for calculating cold capacity was as follows:

  — The data was extracted from DMA and 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.

Public Lighting

The following approach was applied to calculating the variables:

- Public Lighting - Luminaires.

  — The EB RIN 3-5-3.sql script was run to extract the data for the Public lighting luminaires. This script reports the number of luminaires entered into NFM and stored in SLIM.

- Public Lighting Poles: The data was obtained by running Reports through the RIN Configuration Solution for 2018-19.

Note: Numbers may vary from CA 5.2 Asset age tables as methodologies differ between BOPs which results in the exclusion of some data.

- The Reports 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.

- Luminaires reported in this RIN will not equal the figure reported for luminaires in CA RIN 5.2. This is because CA RIN 5.2 excludes non-spatial streetlights. Equipment are consider non spatial when they do not have a Latitude and longitude.

9.5 Assumptions

Circuit Length

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, however:
  - Routes 11 kV and above predominately consist of 3 conductors. However there are some 11 kV routes that are one or two conductors, these are included in the 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.

Circuit Capacity

The following criteria underpin the calculation of these values:

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

Distribution Transformer Total Installed Capacity

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 DMA 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 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 2018;
- Actual Information was available for 2018-19.
- Energex does not have store transformer assets that are only for cold capacity. Energex stores all distribution transformers at store locations , these assets can be used for any situation whether it is for replacement of failed equipment or for future works; and
- The capacity includes strategic spares as well as normal stock holding owned by Energex.

Zone Substation Transformer Capacity

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 2018-19 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 at 30 June 2019;
  - 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.

Public Lighting

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

- Only rating 1 and 2 streetlights have been included in this count;
- Streetlights data does not include assets that are in store or held for spares;
- Rating 3 & 8 have been excluded from this count because they are supplied, installed, owned and maintained by a Public Body; and
- Rating 9 watchman security lighting has also been excluded.

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;
- All timber poles have been excluded even when only a streetlight asset is installed.

9.6 Estimated Information

Refer to Section 8 BOP – 3.5 Physical Assets (Estimated)

9.7 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”.

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.

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.

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

UG/OH lengths

The line lengths reported in RIN Tables 3.5.1.1 and 3.5.1.2 are different (and higher in value) to the line lengths used in the calculation of the weighted average capacities. This is due to the following reasons:

- Reported line lengths in RIN Tables 3.5.1.1 and 3.5.1.2 of the AER EB RIN data BOP are based on construction voltage whereas the rating is calculated based on energised voltage. (For example, feeder IPS3A is constructed at 33 kV but energised at 11 kV. This is reported in the line length table under 33 kV, however, for the calculation of rating, it is not considered as a 33 kV feeder.)

- Line lengths used in the calculation of values in RIN Tables 3.5.1.3 and 3.5.1.4 are considered more up-to-date. The data from Sincal are obtained from design or as-constructed drawings and is updated regularly. GIS/NFM does not carry design information; any updates are based on as constructed information only. There is often a lag between the time a feeder is commissioned and the data is updated in GIS/NFM due to delay in the production of as-constructed drawings.

- In the preparation of RIN Tables 3.5.1.3 and 3.5.1.4, project timings are 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.

Energex line ratings are expressed in current capacity (A), the conversion from A to MVA is done based on nominal voltages of 110 kV or 132 kV. Hence,

For a 110kV circuit, the rating in MVA is calculated based on the formulae below:

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

For a 132kV circuit, the rating in MVA is calculated based on the formulae below:

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

It should be noted that not all circuit length data extracted from DMA were reported in RIN Tables 3.5.1.1 and 3.5.1.2 of the AER EB RIN data BOP due to the following reasons:

- DAPR and EB RIN Tables 3.5.1.1 and 3.5.1.2 utilises circuit construction voltage (segment voltage) instead of energised voltage.
- There are a few underground and overhead length data which were not included in the weighted average capacity calculation due to undefined feeder segments in the feeder length data (for example, MDRTR6H, T31TR4H and 444). Further investigation reveals that these identified segments are within the vicinity of its connecting substation (generally connecting to transformers) and are deemed to be not feeders. The difference in lengths and their effect on the reported values are less 0.1%. Their exclusion is hence considered immaterial.

Zone substations transformer capacity

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 9-13:

Table 9-13 - Calculation of total zone substation transformer capacity for 2018-19

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	8,254
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	8,450
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	3,931
DPA0604	Total zone substation transformer capacity	**Total**	**MVA**	**21,260**
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 (Energex definition cold spare)	MVA	200

Total standby capacity for second step transformation where there are two steps to reach distribution voltage (Energex definition cold + hot spare)		MVA	425
Total standby zone substation transformer capacity where there is only a single step transformation to reach distribution voltage		MVA	
Total		**MVA**	625

10 BOP - 3.6 Quality of Service (Actual)

10.1 Scope of BOP

10.1.1 Table 3.6.1 - Reliability

10.1.2 Table 3.6.4 - Capacity Utilisation

10.2 Compliance with EB RIN Requirements

TABLE 3.6.1 Reliability

Table 10-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 10-1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
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 BOP 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 BOP 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 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.	Reliability data has been reported in accordance 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 2018-19 Regulatory Year in accordance with the requirements in the STPIS.	The MED threshold calculated for the Regulatory Reporting Year was in accordance with the STPIS definition and was applied to the normalised system results.

TABLE 3.6.4 CAPACITY UTILISATION

Table 10-2 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 10-2 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
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 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 10.4 (Methodology) for details.

10.3 Sources

Table 3.6.1 Reliability

Energex has used outage data from the corporate reporting system EPM (Energex Performance Management) which sources its data from PON (Power On). These combined sources were queried to retrieve all sustained transformer interruptions with their customer counts and durations.

Table 10-3 specifies the sources from which Energex obtained the required information.

Table 10-3 - 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	EPM/PON

Table 3.6.4 Capacity Utilisation

Table 10-4 specifies the sources from which Energex obtained the required information.

Table 10-4 - Demonstration of Compliance

Variable Code	Variable	Source
DQS04	Overall capacity utilisation	SIFT (for ratings), SCADA (for load)

10.4 Methodology

Table 3.6.1 Reliability

Energex has used outage data from the corporate reporting system EPM which is supplied outage information by 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 PON.

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]
med 12/13	med13/14	med 14/15	med 15/16	med 16/17	med 17/18	med 18/19
3.32	3.41	3.20	3.32	3.00	3.46	3.391
FINYEAR	DATE	ALL CML	ALL CI	Excl CML	Excl CI	AER_CUST
2018	1/07/2017	43226.01667	784			1451964
2018	2/07/2017	412681.7	2456			1451964
2018	3/07/2017	35693.55	249			1451964
2018	4/07/2017	89879.51667	986			1451964
2018	5/07/2017	3028	26			1451964

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
0.029770722	0.000539958	0	0	NO	0.029770722	0.000539958
0.284223094	0.001691502	0	0	NO	0.284223094	0.001691502
0.024582944	0.000171492	0	0	NO	0.024582944	0.000171492
0.061902028	0.00067908	0	0	NO	0.061902028	0.00067908
0.002085451	1.79068E-05	0	0	NO	0.002085451	1.79068E-05

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

7) To exclude MEDs from the SAIDI and SAIFI calculations the MED threshold was calculated for the Regulatory Reporting Year in accordance with the STPIS guidelines. [1]. This used the historical five year data for SAIDI (2013 - 2017) less

exclusions (column [M] above). The TMED calculation for 2018 Regulatory Year = 3.46 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]
				DQS0105	DQS0107	DQS0106	DQS0108
Ln All SAIDI Less Excl	MED	SAIDI MED	SAIFI MED	All SAIDI Less MED	All SAIFI Less M	All SAIDI Less Excl Less MED	All SAIFI Less Excl Less ME
-3.51422985	NO	0	0	0.02977072	0.000539958	0.02977072	0.000539958
-1.25799581	NO	0	0	0.28422309	0.001691502	0.28422309	0.001691502
-3.7057024	NO	0	0	0.02458294	0.000171492	0.02458294	0.000171492
-2.78220233	NO	0	0	0.06190203	0.00067908	0.06190203	0.00067908
-6.17277007	NO	0	0	0.00208545	1.79068E-05	0.00208545	1.79068E-05

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

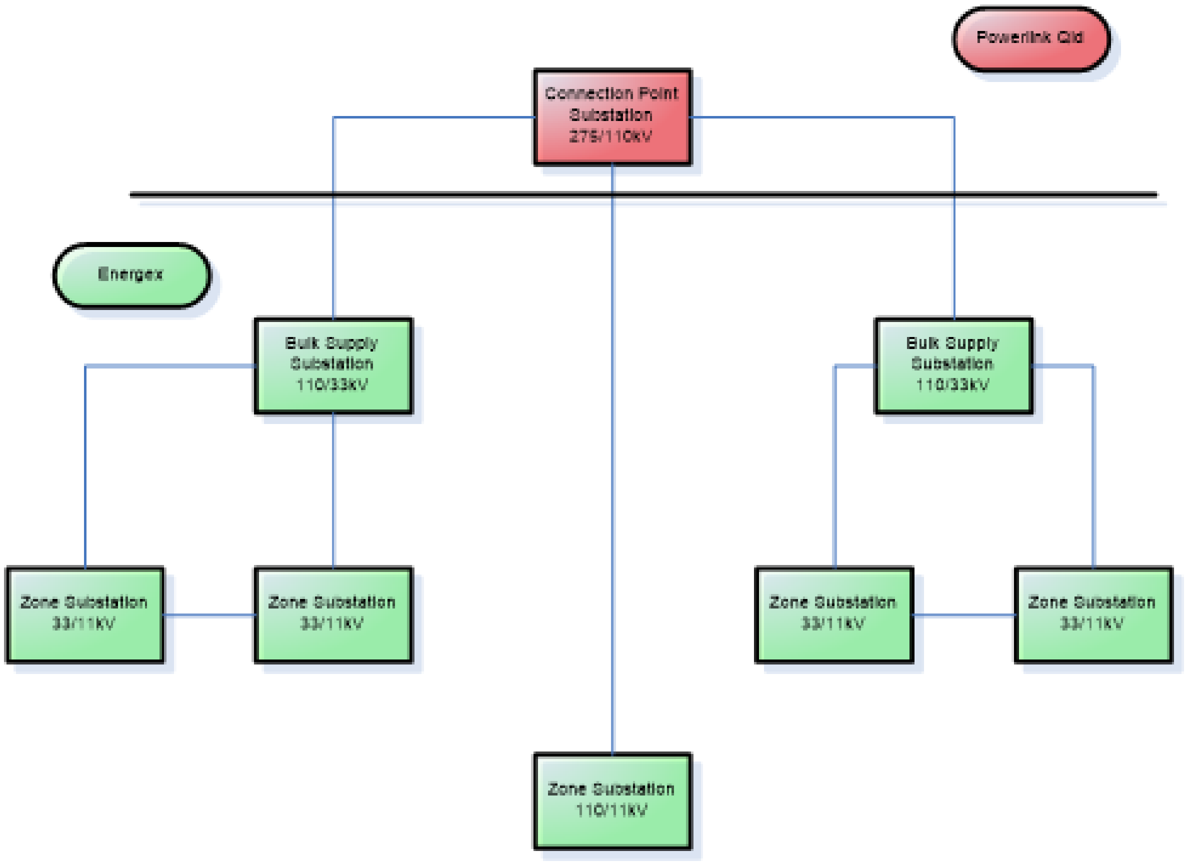
TABLE 3.6.4 CAPACITY UTILISATION

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 (DOPSD0201) divided by the total network zone sub-station thermal capacity (DPA0604) excluding cold spare capacity of zone substation transformers included in DPA0604 (DPA0605), i.e.: DOPSD0201 / (DPA0604-DPA0605)

1) The total network non-coincident maximum demand was obtained from the Energex Metering system and summated for each Regulatory Year (DOPSD0201).

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 (DPA0604).

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

10.5 Assumptions

Table 3.6.1 Reliability

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

2) From the raw source data (277,770 transformer records) there were:

a. 108,689 sustained transformer interruptions. When planned outages, outages with no cause (Null), transformers with no category were removed there were 87,042 valid transformer records during the reporting period.

  - The 87,042 valid transformer records accounted for CML of 233,134,951 which produced a normalised System SAIDI = 233,134,951/1,451,964 = 67.56 minutes.

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 1,436,272 system customers at the start and 1,467,655 at the end of the reporting period were averaged to create a regulatory customer base of 1,451,964.

10.6 Estimated Information

refer to section 11 BOP 3.6 Quality of Service (Esimated)

10.7 Explanatory Notes

Not applicable.

11 BOP 3.6 Quality of Service (Estimated)

11.1 Scope of BOP

11.1.1 Table 3.6.2 - Energy Not Supplied

11.1.2 Table 3.6.3 - System Losses

11.2 Compliance with EB RIN Requirements

Table 3.6.2 Energy Not Supplied

Table 11-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 11-1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions	Demonstrated in section 11.4 (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): • average consumption of the customers interrupted based on their billing history; • feeder demand at the time of the interruption divided by the number of customers on the feeder; • average consumption of customers on the	Demonstrated in section 11.4 (Methodology)

feeder based on their billing history; • average feeder demand derived from feeder Maximum Demand and estimated load factor, divided by the number of customers on the feeder.	
Energy not supplied should be reported exclusive of the effect of Excluded Outages as defined in chapter 9	Demonstrated in section 11.4 (Methodology)

Table 3.6.3 System Losses

Table 11-2 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 11-2 - 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 11.4 (Methodology) for details.

11.3 Sources

Table 3.6.2 Energy not Supplied

Table 11-3 specifies the sources from which Energex obtained the required information.

Table 11-3 - Data Sources

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

11.4 Methodology

Table 3.6.2 Energy Not Supplied

- 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".

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 also extracted from PEACE. The customer minutes lost for each feeder during 2018-19 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 2018-19. 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) 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) In any given year, there tend to be large individual energy not supplied figures due to lengthy planned outages of large customers. The methodology outlined above can overstate the energy loss associated with these interruptions, as these large customers may have multiple points of connection to the Energex network. So a customer may have been partially interrupted (e.g. an interruption to one transformer where the customer has multiple transformers supplying their load), but the customer’s entire energy consumption for the interruption period is attributed to the interruption. A review of feeders with the highest planned energy not supplied figure was carried out, and where it was determined that a customer had multiple connection points, the feeder’s energy not supplied figure was manually reduced by a factor of the number of points of supply to account for this.

7) There is a small portion of the overall supplied energy which has not been able to be assigned to a feeder. The calculated energy not supplied figures were increased by this portion to determine the final energy not supplied figures.

8) A review of the final figures for 2018-19 was carried out, including a comparison to the previous year. This comparison showed that the Energy Not Supplied due to unplanned interruptions had reduced by 4.9% compared to 2017-18. This is predominantly due to improved reliability in 2018-19 year compared to 2017-18. This was validated by comparing the 2018-19 unplanned system SAIDI figure to the 2017-18 figure (inclusive of MEDs). The unplanned SAIDI figure showed a 22.9% decrease in 2018-19 (120.85mins in 2018-19 compared to 156.7 mins in 2017-18).

The Energy Not Supplied due to planned interruptions increased by 46% 2018-19 compared to 2017-18.

Table 3.6.3 System Losses

- DQS03 - System losses is estimated, as it relies on DOPED01 - Total energy delivered, and DOPE0405 - Residential Embedded Generation at On-peak Times.

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.

Basis for Estimation

- Energex constructs a series of Monthly Energy Sales Models for different tariff groups (e.g. 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 (e.g.; 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.

11.5 Assumptions

Table 3.6.2 Energy Not Supplied

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 2018-19 figures customer energy consumption was only available up to April 2019. This is due to customer meter data being manually read on a quarterly basis. Therefore, the period of 1 May 2018 to 30 April 2019 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.

Table 3.6.3 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:

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

11.6 Estimated Information

Justification

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. At the time of calculation, customer energy consumption data was only available up to April 2019 and not the complete financial year, so all values are considered "Estimated".

Basis for Estimation

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

11.7 Explanatory Notes

Not applicable.

12 BOP - 3.7 Operating Environment (Estimated)

12.1 Scope of BOP

12.1.1 Table 3.7.1 - Density Factors

12.1.2 Table 3.7.2 - Terrain Factors

12.2 Compliance with EB RIN Requirements

Table 3.7.1 Density Factors

Table 12-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 12-1 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Demand Density (DOEF0103) is the kVA non-coincident Maximum Demand (at zone substation level) divided by the total number of customers of the network	Demonstrated in section 12.4 (Methodology) Energy and Demand Densities

Table 3.7.2 Terrain Factors

Table 12-2 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 12-2 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
If Energex has Actual Information, Energex must report all years of available data. If Energex does not have Actual Information on	Energex has provided Actual Information where possible. In the absence of Actual Information Energex has estimated figures for

these variables, then it must estimate data for the most recent Regulatory Year.	standard vehicle access (DOEF0213) for the most recent Regulatory Year using the Energex GIS as the distribution route line length that does not fall within the road reserve.
DNSP must report the average number of vegetation related Defects that are recorded per Maintenance Span (DOEF0210 & DOEF0211) in the relevant year.	Demonstrated in section 12.4 (Methodology)
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.

12.3 Sources

Table 3.7.1 Density Factors

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.

Table 3.7.2 Terrain Factors

Table 12-3 specifies the sources from which Energex obtained the required information.

Table 12-3 - Data Sources

Variable Code	Variable	Source

DOEF0213	Standard vehicle access	ArcGIS

12.4 Methodology

Table 3.7.1 Density Factors

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

Energy 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.

Table 3.7.2 Terrain Factors

Standard vehicle access:

- 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.

<u>Approach</u>

- 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.

12.5 Assumptions

Table 3.7.1 Density Factors

- 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.

Standard vehicle access:

- 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.

12.6 Estimated Information

TABLE 3.7.1 Density Factors

- Energex constructs a series of Monthly Energy Sales Models for different tariff groups (e.g. 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 (e.g. 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 (e.g. 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 (e.g. 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.

Table 3.7.2 Terrain Factors

Justification

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

Defects were estimated as Energex does not record the number of defects.

Basis for Estimation

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.

For defects given that Energex does not record this information it can only estimate the number as one per maintenance span.

12.7 Explanatory Notes

Not applicable.

13 BOP 3.7 – Operating Environment (Actual)

13.1 Scope of BOP

13.1.1 Table 3.7.1 - Density Factors

13.1.2 Table 3.7.2 - Terrain Factors

13.1.3 Table 3.7.3 - Service Area Factors

13.2 Compliance with EB RIN Requirements

Table 13-1 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 13-1 - 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 13.4 (Methodology)
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 reported in EB RIN BOP 3.5) as the circuit length may include multiple circuits.	Demonstrated in section 13.4 (Methodology)
Customer density (DOEF0101) is the total number of customers divided by the route Line Length of the network.	Demonstrated in section 13.4 (Methodology)
Demand Density (DOEF0103) is the kVA non-coincident Maximum Demand (at zone substation level) divided by the total	Demonstrated in section 13.4 (Methodology) Energy and Demand Densities

number of customers of the network	
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 BOP 3.7.4 and appropriately coded.
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 BOP 3.7. Energex has, instead, provided this information in the explanatory notes of this basis of preparation (BoP)

Table 13-2 below demonstrates how the information provided by Energex is consistent with each of the requirements specified by the AER.

Table 13-2 - Demonstration of Compliance

Requirements (instructions and definitions)	Consistency with requirements
Rural Proportion (DOEF0201) is Distribution line route length classified as short rural or long rural in km / total network Line Length.	Demonstrated in section 13.4 (Methodology)
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	This definition of Line Length was applied.

sag.	
A vegetation maintenance span (DOEF0202 to DOEF0204) is a span in DNSP's network that is subject to active vegetation management practices in the relevant year. Active vegetation management practices do not include Inspection of vegetation Maintenance Spans	Demonstrated in section 13.4 (Methodology)
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 provided Actual Information where possible. In the absence of Actual Information, Energex has estimated standard vehicle access (DOEF0213) using its GIS as the distribution route line length that does not fall within the road reserve.
If DNSP records poles rather than spans, the number of spans is the number of poles less one	Energex records spans.
The tropical proportion (DOEF0212) 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 13.4 (Methodology)
The bushfire risk variable (DOEF0214) 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:	Demonstrated in section 13.4 (Methodology)

• DNSP's jurisdictional fire authority • local councils • insurance companies • DNSP's consultants • Local fire experts	
Maintenance span cycle (DOEF0206 & DOEF0207) is the planned number of years (including fractions of years) between which cyclic vegetation maintenance is performed for the relevant area	Demonstrated in section 13.4 (Methodology)
CBD and Urban Maintenance Spans (DOEF0202) 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 13.5 (Assumptions) and 13.4 (Methodology).
Rural Maintenance Spans (DOEF0203) 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 13.5 (Assumptions) and 13.4 (Methodology).
Route line length (DOEF0301) 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	Route line length is based on GIS system distance and does not include vertical components.

such as line sag."	
Defects (DOEF0210 & DOEF0211)	Defects are considered as the number of trees per maintenance span

13.3 Sources

Table 3.7.1 Density Factors

Table 13-3 specifies the sources from which Energex obtained the required information.

Table 13-3 - Data Sources

Variable Code	Variable	Source
DOEF0301	Route Line length	ArcGIS
DOPCN01	Total customer numbers	PEACE and SLIM (UMS only)
DOEF0101	Customer Density	PEACE

Table 3.7.2 Terrain Factors

Table 13-4 specifies the sources from which Energex obtained the required information.

Table 13-4 - Data Sources

Variable Code	Variable	Source
DOEF0201	Rural proportion	ArcGIS
DOEF0202	Urban and CBD vegetation maintenance spans	Contractors Data system
DOEF0203	Rural vegetation maintenance spans	Contractors Data system

DOEF0204	Total vegetation maintenance spans	Contractors Data system
DOEF0208	Average number of trees per urban and CBD vegetation maintenance span	Contractors Data system
DOEF02010 and DOEF02011	Average number of defects per vegetation maintenance span	Contractors Data system
DOEF0209	Average number of trees per rural vegetation maintenance span	Contractors Data system
DOEF0205	Total number of spans	ArcGIS
DOEF0206	Average urban and CBD vegetation maintenance span cycle	Ellipse
DOEF0207	Average rural vegetation maintenance span cycle	Ellipse
DOEF0212	Tropical proportion	ArcGIS/ BOM
DOEF0214	Bushfire risk	ArcGIS/ Queensland Government

13.4 Methodology

Table 3.7.1 Density Factors

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

Customer Density

DOEF0101 – Customer density was calculated by dividing the total number of customers (DOPCN01 from RIN Table 3.4.2.1) divided by the route Line Length (DOEF0301 from RIN Table 3.7)

Energy Density

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.

Demand Density

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 kVA.

Table 3.7.2 Terrain Factors

Rural Proportion:

- 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).

Maintenance Spans and Tree Numbers:

- These numbers are determined by the information reported from the contractors' databases.

Span numbers, tropical proportion and bushfire risk:

- 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.

Maintenance Span Cycles:

- Average maintenance span cycle was calculated based on data sourced from the June monthly report for the Annual Vegetation Management Program (June 2019) taken from the Ellipse database (i.e. 2018-19 data was found in the June 2019 report).

A methodology was employed whereby:

- Average urban vegetation maintenance span cycle = (Sum of treated Urban vegetation zones cycle duration [Maintenance Schedule Task]/total number of Urban Vegetation Zones treated during regulatory (financial)year;
- Average rural vegetation maintenance span cycle = (Sum or treated Rural vegetation zones cycle duration [Maintenance Schedule Task]/total number of Rural Vegetation Zones treated during regulatory (financial) year.

Maintenance Spans and Tree Numbers:

- This information has been exported from the vegetation contractors' database

Span numbers, tropical proportion and bushfire risk:

- The total number of overhead spans was obtained by extracting the figures directly from ArcGIS.
- The tropical proportion variable was calculated by overlaying the Australian Bureau of Meteorology Australian Climatic Zones GIS shapefile 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.
- The bushfire risk variable was calculated by overlaying the Queensland Government Department Queensland Spatial Catalogue – Qspatial Bushfire Risk Maps (Wide Bay and South East Queensland) 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.

Defects:

- Energex does not record specific information on defects. Each tree is seen as one defect as Energex does not record more specific information than this on defects. Therefore the number of trees per maintenance spans is replicated here as the number of defects.

13.5 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.

Rural Proportion:

The calculation of this variable assumed that:

- Vegetation Zones are allocated as urban or rural dependent upon the type of vegetation growing within that zone, typically an urban Vegetation Zone is an area where more than five adjacent properties have a road frontage of < 40 metres per property. Rural Vegetation Zones are areas that do not fit into the Urban category

Maintenance Spans and Tree Numbers:

- This information has been exported form the contractors' database

13.6 Estimated Information

Refer to Section 12 BOP – 3.7 Operating Environment (Estimated)

13.7 Explanatory Notes

The Route line length (DOEF0301) reported in the EB RIN will not align with the route line length reported in BOP 2.7 Vegetation Management of the Category Analysis (CA) RIN. The CA RIN route line length is that which is trimmed in the regulatory year (not all lines are trimmed every line every year). The EB RIN figure is the total length of lines overhead and underground of the Energex network.

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