

Energex

Asset Management Division

**Augex model supporting information**

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

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

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# Introduction

## Background

The AER indicated in its Better Regulation - Expenditure Forecast Assessment Guidelines for Electricity Distribution that it intends to use its Augex model to help determine the forecast network augmentation requirements over the forthcoming regulatory control period. It is expected that the model will be used to provide a high level mechanistic assessment in order to identify areas of expenditure that may require more detailed examination.

Planning of network augmentation expenditure requirements is a core business function performed by Energex and is critical in network planning and asset management. Energex has developed a rigorous process to develop augmentation expenditure requirements on a bottom up project basis, to meet specific network requirements. Importantly, it should be noted that Energex has not used the Augex model to forecast augmentation expenditure for the forthcoming regulatory control period, rather it is populated to comply with the AER’s requirements.

## Purpose

The purpose of this document is to set out the information requested by the AER in Reset Regulatory Information Notice (RIN) Schedule 1 Section 7, Augmentation Capital Expenditure modelling. It describes, amongst other matters, the methodologies, assumptions and sources of information relating to augmentation capital expenditure modelling, to support the data provided in Regulatory Template 2.4.

This document has been prepared with reference to the AER’s Augex model guidance document[[1]](#footnote-2).

## Structure

The document is set out in the following main sections:

1. Network segments
2. Maximum demand data
3. Asset ratings
4. Growth rate
5. Capex capacity
6. Utilisation threshold
7. Capacity factors
8. Augmentation unit costs
9. Unmodelled augmentation
10. Unique factors affecting the Energex network
11. Reset RIN Schedule 1 checklist

## Document terminology

The following table defines terms used by Energex, to clarify any terminology in this document that may differ between Energex and the AER, and to define specific systems used by Energex.

Table 1‑1 - Energex Terminology

| Term | Description |
| --- | --- |
| Sub-transmission lines | Lines with an operating voltage of 132 kV, 110 kV or 33 kV. |
| Sub-transmission substations  | Substations operating with a primary voltage of 132 kV or 110 kV and a secondary voltage of 33 kV. Also known as bulk supply substations. |
| Sub-transmission switching stations | Switching stations operating at a voltage of less than or equal to 132 kV and greater than 11 kV. |
| Zone substations | Substations operating with a primary voltage of 132 kV, 110 kV or 33 kV and a secondary voltage of 11 kV. |
| HV feeders | Assets with an operating voltage of 11 kV or 6.35 kV (SWER). |
| Distribution substation | Transformers with a primary side voltage of less than or equal to 11 kV. For the purpose of the Augex model, the augmentation requirements of the low voltage network are included in the cost of the distribution substations. |
|  |  |
| Switching station | A station that connects to multiple circuits but does not contain a transformer. |
| NetPlan | NetPlan is an Energex developed Distribution Planning Tool and Database. |
| ERAT | ERAT is an Energex developed plant rating database. |
| ERAT2 | ERAT2 is an Energex developed plant rating database. |
| DMS | Distribution Management System – is the system used to operate and manage the network in real time. |
| SIFT | Substation Investment and Forecast Tool is an Energex developed planning database. |
| DAPR | Distribution Annual Planning Report 2014. |
| NFM | Network Facilities Management, which is the main database used by Energex to record and manage asset data and information regarding network outages. |

## Observations

Energex notes that the Augex model has not previously been used by the AER to assess Energex’s augmentation expenditure as part of a regulatory determination. The outcomes are therefore untested and, Energex considers, carry a high degree of uncertainty.

The Augex model uses network utilisation, a target utilisation threshold and demand growth to predict future expenditure requirements. Its inputs are therefore restricted to augmentation driven by growth in peak demand only. Other drivers of augmentation expenditure such as reliability, power quality, fault level constraints and other compliance obligations (including public and staff safety) are not modelled as Augex. These other, unmodelled factors comprise a significant component of Energex’s augmentation expenditure forecast.

Augmentation at sub-transmission level is similar to that of a Transmission Network Service Provider, characterised by relatively small numbers of large, unique projects with spend over multiple years. These types of projects are sufficiently important to the security of the network and limited in number, therefore warranting individual engineering assessment.

Data availability is extremely limited for the Augex modelling of distribution transformers and Low Voltage (LV) network. Energex has applied sample data across the whole asset class for the purposes of populating the model. However, emerging issues such as solar PV and batteries and the impact of these technologies on the LV network limit the usefulness of historical data.

# Network segments

## Segment groups

The segment groups are specified by the AER in Regulatory Template 2.4.5 and are defined in Table 2‑1 below.

Table 2‑1 - AER Segment group definitions

| ID | Segment group | AER Definition |
| --- | --- | --- |
| 1 | Subtransmission lines | A distribution line with a nominal voltage that is above 33 kV, and connects a sub-transmission substation to a zone substation.Includes all connected lines and cables from the point of origin to the normally-open points or line/cable terminations. |
| 2 | Subtransmission substations and switching stations  | A substation on a distribution network that transforms any voltage to levels above 33 kV or switching station that connects to multiple circuits above 33 kV but does not contain a transformer.For the purposes of populating regulatory template 2.4 (Augex model), a sub-transmission substation is a substation on a distribution network that transforms any voltage to levels above 22 kV and is not a bulk supply point.Refer to the QLD Reset RIN 2015 Appendix F for further details regarding this definition.  |
| 3 | Zone substations | A substation on a distribution network that transforms any voltage above 33 kV to levels at or below 33 kV but above 1 kV.Refer to the QLD Reset RIN 2015 Appendix F for further details regarding this definition. |
| 4 | HV feeders – (by feeder category) | A distribution line with a nominal voltage that is at or below 33 kV and above 1 kV, and connects distribution substations to a zone substation.Includes all connected lines and cables from the point of origin (typically a zone substation) to the normally-open points or line/cable terminations.Feeder categories have the meaning described in the Service Target Performance Incentive Scheme, November 2009. |
| 5 | Distribution substation – (by feeder category and including downstream LV network)  | A substation on a distribution network that transforms voltage of levels at or below 33 kV but above 1 kV to levels below 1 kV.Feeder categories have the meaning described in the Service Target Performance Incentive Scheme, November 2009. |

### Departures from the AER’s definitions

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

#### Sub-transmission lines

As indicated in section 1.4, Energex uses a different definition for sub-transmission in its normal day to day operations. The key difference is that Energex considers sub-transmission to include 33 kV lines, as the purpose of those lines is to provide interconnection between zone substations, not to connect zone substations to distribution substations as indicated by the Reset RIN HV feeder definitions.

Energex has therefore applied its own definition of sub-transmission lines for the purposes of the Augex model and considers that this is consistent with the intention of the AER definition.

#### Zone substations

As indicated in section 1.4, Energex uses a different definition for zone substations in its normal day to day operations. If Energex was to adopt the Reset RIN definitions, all of its 33/11 kV substations would not be classed as zone substations. This appears contrary to the intended operation of the model to have a clear separation of elements with different cost structures and growth drivers.

Energex has therefore applied its own definition relating to zone substations for the purposes of the Augex model and considers that this is consistent with the intention of the AER definition.

## Network segments composition

The Augex model requires that the segment groups established by the AER be disaggregated into network segments. The network segments must reflect the broad grouping of network components where the same planning and operating processes would be applied, where they have a similar network topology and a similar utilisation.

Energex has applied this approach in disaggregating segment groups into network segments for the purposes of the Augex model. All network segments, by segment group, are listed in Table 2‑2.

Table 2‑2 – Augex network segments

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

Broadly, the segments groups are disaggregated based on a range of parameters, being:

* Operating voltage
* Network topology
* Overhead and underground construction
* Demand growth
* Capacity

This is discussed in further detail below.

### Sub-transmission lines

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

#### Definition and reasoning for composition

Energex disaggregated the network group into 24 unique network segments. The segments were disaggregated based on the following four parameters:

* Operating voltage
* Network topology
* Overhead and underground construction
* Demand growth

**Operating voltage**

Energex has disaggregated sub-transmission lines based on the following voltage categories:

* 110 & 132 kV
* 33 kV

The voltage of assets has a material impact on the augmentation unit cost and capacity factors required by the Augex model.

**Network topology**

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

Energex has disaggregated sub-transmission lines based on the following four topology categories:

* Single radial feeder
* Double radial feeder
* Triple radial feeder
* Mesh/complex feeders

A single radial feeder connects a sub-transmission substation or switching station to another sub-transmission substation or zone substation. Loss of the feeder results in total loss of supply downstream.

A double radial feeder includes two separate lines that connect a sub-transmission substation or switching station to another sub-transmission substation or zone substation. Loss of a feeder does not result in total loss of supply downstream, but may result in partial loss of supply and leaves the network vulnerable to other events.

A triple radial feeder includes three separate lines that connect a sub-transmission substation or switching station to another sub-transmission substation or zone substation. Loss of a feeder does not result in total loss of supply downstream, but will change the power flows in the remaining feeders.

Mesh/Complex (Mesh) feeders include multiple feeders from multiple sources connecting to a substation such that the substation can be supplied from either source. Loss of a feeder does not result in loss of supply downstream, but will change the power flows in the remaining feeders.

**Overhead and underground construction**

Energex also disaggregated sub-transmission lines into underground and overhead segments. The construction of assets as either overhead or underground has a material impact on augmentation unit costs required for the Augex model.

Disaggregation between overhead and underground segments was based on the total length. If the existing network was greater than 50% overhead, it was assumed that future augmentation would be overhead. Likewise, if the existing network was greater than 50% underground, it was assumed that future augmentation would be underground.

**Demand growth**

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

#### Boundary issues

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

### Sub-transmission and Zone substations

For substations the AER requires reporting against two segment groups, being:

* Sub-transmission substations and sub-transmission switching stations
* Zone substations

The following sections discuss how Energex defined these segment groups and the composition of each network segment within these segment groups.

#### Definition and reasoning for composition

Energex disaggregated the two network groups into 14 unique network segments:

* four network segments for sub-transmission substations and sub-transmission switching stations, which included bulk supply substations
* ten network segments for zone substations.

The segments were disaggregated based on the following parameters:

* Operating voltage
* Network topology
* Demand growth

**Operating Voltage**

The operating voltage of the substations has a material impact on augmentation unit cost, capacity factor and utilisation threshold parameters of the Augex model and was therefore considered an appropriate basis on which to disaggregate this segment group, in line with AER requirements.

The zone substations segment group was therefore disaggregated into zone substations (33/11 kV) and direct transformation substations (132/11 kV or 110/11 kV).

The sub-transmission substations and sub-transmission switching stations segment group included only sub-transmission substations (132/33 kV or 110/33 kV) and was not disaggregated by operating voltage.

**Network topology**

The number of transformers in a substation has a material impact on the capacity factor and utilisation threshold parameters of the Augex model and was therefore considered an appropriate basis on which to disaggregate this segment group, in line with AER requirements..

Energex disaggregated sub-transmission lines based on the following three topology categories:

* Single transformer substations
* Double transformer substations
* Triple transformer substations

A single transformer substation connects the sub-transmission network to the next voltage level through one transformer. Loss of the transformer results in total loss of supply downstream.

A double transformer zone substation connects the sub-transmission network to the next voltage level through two transformers operating in parallel. Loss of a transformer does not result in total loss of supply downstream, but may result in partial loss of supply which requires transfers or generators to restore.

A triple transformer zone substation connects to the sub-transmission network to the next voltage level through three transformers operating in parallel. Loss of a transformer does not result in total loss of supply downstream, but may result in partial loss of supply which requires transfers or generators to restore.

**Demand growth**

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

#### Boundary issues

A boundary issue relating to the zone substation network segments was that typical zone substation projects can include works related to additional network secments. This may include:

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

Energex has addressed these issues through the development of network segments including the augmentation unit costs and capacity factors discussed in sections 8 and 9 respectively.

### HV feeders

For HV feeders the AER required reporting against four segment groups, being:

* High voltage feeders - CBD
* High voltage feeders - urban
* High voltage feeders - short rural
* High voltage feeders - long rural

The following sections discuss how Energex has defined the segment groups and the composition of each network segment.

#### Definition and reasoning for composition

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

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

The segments were further disaggregated based on the following parameters:

* Demand growth
* Network topology

**Demand growth**

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

**Network topology**

CBD feeders were also disaggregated into additional network segments to account for the complexity of the network and the degree to which it is meshed. Urban and short rural segment groups were not disaggregated further. The network topology is set out in Table 2‑3.

Table 2‑3 - HV feeder topology

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

#### Boundary issues

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

### Distribution Substations (including LV network)

For distribution substations the AER established four segment groups, being:

* Distribution substations - CBD (including downstream LV network)
* Distribution substations - urban (including downstream LV network)
* Distribution substations - short rural (including downstream LV network)
* Distribution substations - long rural (including downstream LV network)

The following sections discuss how Energex defined the segment groups and the composition of each network segment within those groups.

#### Definition and reasoning for composition

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

Energex disaggregated the segment groups based on distribution transformer capacity in kVA:

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

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

#### Boundary issues

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

# Maximum demand data

This section provides explanation of maximum demand data provided in Regulatory Template 2.4, tables 2.4.1, 2.4.2, and 2.4.3. Maximum demand data for distribution substations was not requested by the AER in table 2.4.4, therefore an approach is not included for these network segments.

## Approach to forecasting

The following subsections describe the approach to demand forecasting for each of the segment groups. Energex has provided additional information regarding its demand forecasting methodologies in in the paper prepared in response to section 8, Schedule 1 of the Reset RIN, Demand, Customer Number and Energy Forecasting Methodologies.

### Sub-transmission lines maximum demand forecast methodology

Energex used PSS/E to model the 132 kV and 110 kV sub-transmission network. The software was selected to align with tools used by Powerlink and the Australian Energy Market Operator (AEMO). Powerlink provides a base model to Energex on an annual basis. This base model was then uploaded with peak forecast loads at each bulk supply point and connection point zone substation from SIFT.

Energex used SINCAL to model the 33 kV sub-transmission network. Simulation models are created using the existing network data. The forecast peak loads at each substation were uploaded into the model from SIFT.

The output of the models was verified through a reconciliation process with the substation demand forecasts.

### Sub-transmission and zone substation maximum demand forecast methodology

Energex employed a bottom up approach to develop the ten year zone substation maximum demand forecasts using validated historical peak demands and expected load growth based on demographic and appliance information in small area grids. Larger block loads were included separately after validation for size and timing by Asset Managers.

The zone substation peak demand forecasts were then aggregated up to the ten year bulk supply point, and transmission connection point demand forecasts, and accounted for diversity of individual zone substation peak demands and network losses. This aggregated forecast was then reconciled with the independent system demand forecast and adjusted as required.

The high level process used to develop the ten year substation demand forecast was as follows:

* Validated uncompensated substation peak demands were determined for summer 2013/14 from the SCADA system. This is accurate within ±5.0%, which was the best available data.
* Minimum and maximum temperature at five Bureau of Meteorology weather stations were regressed against substation daily maximum demand to assess the impact of each set of weather data on substation demand (Amberley, Archerfield airport, Coolangatta airport, Brisbane airport and Maroochydore airport). The best fit relationship is used to determine the temperature adjustment.
* Industrial substations tend not to be sensitive to temperature and the 50% PoE and 10% PoE adjustments were based solely on demand variation.
* Previous substation peak demand forecasts were reviewed against temperature adjusted results and causes of forecast error were identified.
* Starting values for MVA, MW and MVAr were calculated for four periods – summer day, summer night, winter day and winter night.
* Demographic and population analysis was undertaken and customer load profiles are prepared for Energex.
* Year-on-year peak demand growth rates were determined from the customer load profiles prepared for Energex, historical growth trends and local knowledge from Asset Managers using a panel review (Delphi) process.
* Size and timing of new block loads were reviewed and validated with Asset Managers before inclusion in the forecast.
* Size and timing of load transfers were also reviewed with Asset Managers before inclusion in the forecast.
* Timing and scope of proposed projects were reviewed with development planners before inclusion in the forecast.
* The growth rates, block loads, transfers and projects were applied to the starting values to determine the forecast demand for each of the ten years starting from a coincident demand basis.
* Zone substation forecast peak demands were aggregated up to transmission connection point demands through the bulk supply substations using appropriate coincidence factors and losses.
* Reconciliation of the total aggregated demand with the independently produced system demand forecast ensures consistency for the ten year forecast period.
* Includes peak demand reduction through audio frequency load control (AFLC) based demand management.

Substation peak demand forecasts are reviewed each season and compared with previous forecasts.

### HV feeder maximum demand forecast methodology

Forecasting of 11 kV feeder loads was done on an individual feeder basis. The forecast first established a feeder load starting point by undertaking bi-annual 50% PoE temperature corrected load assessments (post summer and post winter).This involved allowing for abnormal operating conditions by identifying and removing any temporary (abnormal) loads and transfers; then analysing daily peak loads for day and night to identify the load expected at a 50% PoE temperature.

The 11 kV feeder forecast is part of a system called NetPlan that stores the forecast as a series of events in date order for each zone substation and calculates the resulting forecast load in Amps in the 11 kV feeders for summer day, summer night, winter day and winter night. It uses rating data to calculate thermal and secondary system utilisation forecasts for the same four seasons.

## Relationship to normal planning

### Sub-transmission lines, sub-transmission substations, zone substations and HV feeders

The maximum demand data provided in Reset RIN tables 2.4.1, 2.4.2 and 2.4.3 for sub-transmission lines, sub-transmission substations, zone substations and HV feeders align with maximum demand forecast used in Energex’s normal planning process.

### Distribution substations

Maximum demand is not required in Reset RIN table 2.4.4.

## Derivation of maximum demand values

This section sets out, for each set of segment groups, whether forecasts of maximum demand values are based on measured or estimated values.

### Sub-transmission lines

Maximum demand was estimated based on the load flow results of Sincal and PSS/E, which in turn that utilise the substation maximum demand from SIFT. The results were validated using industry standard load flow models to calculate loads in electrical networks.

### Sub-transmission and zone substations

Maximum demand was based on a measured value, measured on the secondary side of the transformer.

Maximum demand data for sub-transmission and zone substation forecasts were based on the ten year zone substation forecast. The forecast utilises SCADA measurements of transformer load and independent weather stations to provide temperature data. The measurements were validated to account for abnormal conditions such as network maintenance or outages as part of the forecasting methodology.

### HV Feeders

Maximum demand was based on a measured value, measured on the circuit breaker at the head of the feeder.

Abnormal operating conditions are allowed for by identifying and removing any temporary (abnormal) loads and transfers; then analysing daily peak loads for day and night to identify the load expected at a 50% PoE temperature.

### Distribution substations

Maximum demand is not required in Reset RIN table 2.4.4.

## Relationship to raw unadjusted demand and 10% PoE

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

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

# Asset ratings

## Calculation of ratings

Energex extracted asset rating information from two databases being:

* ERAT for HV feeders
* ERAT2 for sub‑transmission assets

Distribution transformer ratings are were based on the nameplate rating of the assets which is in NFM.

The capacity ratings for each asset were based on industry standard models. Details of the calculations are set out in the Energex Plant Rating Manual[[2]](#footnote-3), including the range of assumptions applied, such as manufacturer data, duty cycle, temperatures, type of cooling for transformers, and type of installation for underground cables. Site specific calculations may be undertaken for abnormal situations.

## Relationship to normal ratings

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

Table 4‑1 - Mapping between planning and operating asset ratings

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

As shown in Table 4‑1, there is a clear relationship between the use of ratings for planning and operations.

The AER’s Augex Model Handbook[[3]](#footnote-4) require that the nominal thermal rating is used to ensure the rating provided is independent of the unique network arrangements of Energex. To address this requirement, Energex used the nominal rating for its assets based on standard conditions, as set out in the Plant Rating Manual[[4]](#footnote-5), that are stored in the ERAT and ERAT2 databases. The following two exceptions were made:

* Transformers operated in parallel may not share load equally. This can be due to differences in impedance. Therefore, substation ratings were calculated values. Based on the rating obtained from ERAT2, the SIFT calculated the substation rating taking into account the load sharing between transformers.
* For HV feeders, Energex used the feeder trunk assumption as recommended in section 5.1.2 of the Augex Model Handbook. The rating used was the lowest rating of the first three segments of the feeder.

Energex considered that the use of these ratings was appropriate for the Augex model, and was the most accurate reflection of data used to forecast augmentation requirements.

# Growth rate

The AER’s Augex model requires that the utilisation growth rate represents the average annual compound rate of growth in utilisation over the forecast period. This growth rate reflects the average annual growth in weather corrected 50% PoE peak demand[[5]](#footnote-6).

This section provides explanation of the annual average growth in maximum demand data provided in tables 2.4.1, 2.4.2, 2.4.3 and 2.4.4 of Regulatory Template 2.4 of the Reset RIN.

## Sub-transmission lines, sub-transmission substations and zone substations

The 50 PoE demand forecast for each asset was first calculated for 2013/14 and 2019/20. Next, the growth rates required for tables 2.4.1 and 2.4.3 were derived from maximum demand forecasts using the formula below, which derives the compound average annual growth rate.

$$growth rate (\%)=\sqrt[6]{\frac{2019/20 Maximum Demand}{2013/14 Maximum Demand}}$$

## HV feeders

The 50 PoE demand forecast for each HV feeder was first calculated for 2013/14 and 2016/17. HV feeder demand is driven by underlying demand growth combined with additional block loads that can be volatile in timing and capacity requirements. To mitigate the impacts of this volatility, the 2016/17 demand forecast was used to calculate the growth rate of HV feeders, this approach aligns with Energex’s typical approach to HV feeder planning.

The growth rates required for table 2.4.2 were derived from maximum demand forecasts using the formula below, which derives the compound average annual growth rate.

$$growth rate (\%)=\sqrt[3]{\frac{2016/17 Maximum Demand}{2013/14 Maximum Demand}}$$

## Distribution substations

The growth rates for each network segment were calculated based on the HV feeder demand forecast methodology, described in section 3.1.3, excluding customer block loads. Block loads were excluded from growth rate as they were addressed through customer initiated projects.

The distribution substation annual growth rate was calculated, using the below formula, for each of the reliability categories; Rural, Urban and CBD (High Density).

$$growth rate (\%)=\sqrt[6]{\frac{2019/20 Maximum Demand}{2013/14 Maximum Demand}}$$

# Capex Capacity

This section provides explanation data provided in table 2.4.6 of Regulatory Template 2.4 of the Reset RIN.

## Types and costs and activities

The costs included in table 2.4.6 include direct, fleet and material on-costs.

Energex included the following non-field analysis and management costs in the capex:

* Fleet oncost
* Material oncost
* Planning
* Project management

Overall these costs represent approximately 6.0% of augmentation capital expenditure.

## Allocation of actual expenditure and capacity to segment groups

Actual expenditure and capacity added was allocated to table 2.4.6 at the project level consistent with reporting in Regulatory Template 2.3 (Augex) of the Reset RIN. Information regarding customer initiated augmentation was include in the Regulatory Template 2.5 (Connections) of the Reset RIN and not reproduced in table 2.4.6.

A detailed explanation of how actual information was derived is provided in the Reset RIN Basis of Preparation for table 2.4.6. A summary of the process applied is as follows:

* Augmentation expenditure was allocated at the project level based on the primary segment group impacted by the project.
* Augmentation Projects that were trigged by demand growth were included as modelled augmentation.
* Remaining expenditure was then assigned to the unmodelled augmentation category.

Energex does not allocate expenditure to the network segments used in the Augex model as part of normal internal reporting practices.

## Allocation of estimated/forecast expenditure and capacity to segment groups

Estimated and forecast expenditure and capacity added was allocated at the project level, consistent with reporting in Regulatory Template 2.3 (Augex) of the Reset RIN. Information regarding customer initiated augmentation was included in the Regulatory Template 2.5 (Connections) of the Reset RIN and not reproduced in table 2.4.6.

The estimated and forecast expenditure for all segment groups was allocated based on the proposed program of work, and therefore are directly related to current project and a program plans.

### Sub-transmission lines, sub-transmission substations and zone substations

The following allocation process was applied to determine and allocate estimated expenditure and capacity to sub-transmission lines, sub-transmission substations and zone substations:

* Augmentation expenditure was allocated at the project level based on the primary segment group impacted by the proposed project.
* Augmentation projects that were trigged by demand growth were included as modelled augmentation.
* Remaining expenditure was then assigned to the unmodelled augmentation category.
* Capacity added for each of the network segments was based on the capacity forecast to be installed by each project in the forecast year of commissioning.

### HV feeders

Modelled HV feeder augmentation expenditure was forecast based on the following augmentation programs:

* 11 kV feeder tie capacity
* 11 kV new underground feeder
* 11 kV new overhead feeder
* 11 kV reconfigure CBD mesh network

The estimated and forecast expenditure was apportioned to the Augex network categories based on the allocation set out in Table 6‑1. It should be noted that Energex does not have any long rural assets.

Table 6‑1 – HV expenditure allocation

|  |  |  |  |
| --- | --- | --- | --- |
| Augmentation program | CBD | Urban | Short Rural |
| 11 kV feeder tie capacity |  | 40% | 60% |
| 11 kV new underground feeder | - | 100% |  |
| 11 kV new overhead feeder | - | 30% | 70% |
| 11 kV reconfigure CBD mesh network | 100% | - | - |

Due to the dynamic nature of 11 kV distribution networks it was not practical to produce project level forecasts over a five year period. This is because projects are raised against 11 kV feeder augmentation programs as prevailing limitations are identified. However, any specific projects that were identified were allocated directly to the relevant Augex network segments.

Capacity added for established projects was based on the capacity forecast to be installed by each project in the forecast year of commissioning.

Capacity added by the 11 kV feeder augmentation programs was estimated by the number of new feeders forecast to be required in the forthcoming regulatory period and the standard capacity of new feeders as set out in Energex’s Plant Rating Manual[[6]](#footnote-7).

Remaining HV feeder augmentation expenditure was then assigned to the unmodelled augmentation category.

### Distribution substations

Specific distribution substation projects are triggered through site inspection and are typically completed within three months. Due to the short cycle time of these projects no specific projects are included in the estimated and forecast expenditure.

Modelled distribution substation augmentation was therefore forecast based on the following augmentation programs:

* CA03 – Uprate Pole transformer
* CA04 – Uprate Padmount transformer

Remaining Distribution substation and LV network augmentation expenditure was then assigned to the unmodelled augmentation category

# Utilisation threshold

The AER requires Energex to provide the utilisation threshold statistics, mean and standard deviation, for each network segment defined in table 2.4.5 of the Reset RIN. The AER defines the utilisation threshold as the point when assets need to be augmented, that is where the asset will breach reliability standards or exceed the economic point of maximum utilisation[[7]](#footnote-8). This section explains the utilisation threshold statistics provided and justifies the approach taken.

Table 2.4.5 of the Reset RIN requires both historic and forecast utilisation threshold parameters. Section 7.1 details the methodology used to calculate the forecast and historic parameters.

## Methodology, data sources and assumptions

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

### Sub-transmission and zone substation network segments

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

* Sub-transmission lines
* Sub-transmission substations and sub-transmission switching stations
* Zone substations.

#### Forecast parameter methodology

For each individual network segment, Energex:

* Extracted the Normal Cyclic Capacity (NCC) from the Load flow models/ERAT2 (feeders) or SIFT (substations) database for system normal conditions.
* Extracted the emergency cyclic rating (ECC) from SIFT (substations) database as the “*N-1 emergency*” capacity. The capacity for feeders was considered the same as NCC as there was no ECC for feeders.
* Applied consistent assumptions to each network segment for the average available transfers and generation as shown in Table 4.1.
* Calculated the utilisation threshold for each network segment using Equation 1 below.
* Calculated the mean and standard deviation for the data series using Equations 2 and 3 below.

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

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

Where:

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

The maximum utilisation threshold based on 50% PoE load was capped at 88%, as Energex plans the network to support 10% PoE load under system normal configuration.

The utilisation for each asset was calculated and allocated to the data series for the network segment.

Equations 2 and 3 below outline the methodology used to calculate the mean utilisation threshold and standard deviation for that network segment using the data series:

Mean utilisation threshold = $\frac{\sum\_{1}^{N}UT}{N}$ ……………………………………..………..Eqn 2

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

Where:

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

#### Historic parameter methodology

A sample of 64 Planning Approval Reports was reviewed for the network segments of sub-transmission lines, sub-transmission substation, and zone substation to establish the asset utilisation at the time of augmentation. The sample size for each network segments is shown in Table 7‑1. The list of projects reviewed contained projects with project expenditure greater than $5 million that were commissioned between 2009/10 and 2013/14.

Table 7‑1 - Review of past projects

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

#### Sources

Energex calculated the utilisation threshold for each feeder using the remaining capacity under an outage condition, plus any available load transfers and generation. The outage condition capacities were obtained from ERAT2, the available load transfers were calculated as a network average based on load flow studies, and the available generation was assumed to be the maximum amount allowed by the Safety Net Targets[[8]](#footnote-9).

Historic parameters were recorded from Planning Approval Reports.

#### Assumptions

The following assumptions were applied to derive the utilisation threshold statistics:

* Single radial does not apply to CBD substations.
* Double radial and triple radial assume all feeders/transformers have equal impedances and therefore carry an equal share of the load.
* Available transfer capacity and generation assumptions are as described in Table 7‑2.

Table 7‑2 Transfer and generation capacity assumptions

|  | Substations | Feeders |
| --- | --- | --- |
| Assumption | Single  | Double | Triple | Single  | Double | Triple |
| Urban Zone Average Transfer Capacity  | 6 MVA | 6 MVA | 6 MVA | - | - | - |
| Rural Zone Average Transfer Capacity  | 1 MVA | 1 MVA | 1 MVA | - | - | - |
| Bulk Supply Average Transfer Capacity  | N/A | 18 MVA | 18 MVA | - | - | - |
| Urban allowable generation  | 4 MVA | 4 MVA | 4 MVA | 4 MVA | 4 MVA | 2 MVA |
| Rural allowable generation  | 10 MVA | 10 MVA | 10 MVA | 10 MVA | 10 MVA | 5 MVA |
| Urban Sub-Transmission Lines Average Transfer Capacity  | - | - | - | 6 MVA | 6 MVA | 3 MVA |
| Rural Sub-Transmission Lines Average Transfer Capacity  | - | - | - | 1 MVA | 1 MVA | 0.5 MVA |
| Transmission Lines Average Transfer Capacity | - | - | - | 18 MVA | 18 MVA | 9 MVA |

### HV feeders network segments

Energex applied the same methodology to all HV feeder network segments, being the segments in the following AER segment groups:

* High voltage feeders - CBD
* High voltage feeders - urban
* High voltage feeders - short rural

The approach taken for each segment group was based on the Energex planning standards.

#### Historic and forecast parameter methodology

**HV feeders (Urban and short rural)**

A sample of 93 historic projects was reviewed for the segment groups to estimate the historic asset utilisation at the time of augmentation. The sample size for each network segment is shown in Table 7‑3‑.

Table 7‑3 - Review of past projects

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

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

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

**HV Feeders (CBD)**

A sample of five historic CBD projects was reviewed to estimate the historic asset utilisation at the time of augmentation of CBD three feeder mesh networks.

For the CBD three feeder mesh network segment, there was no change in Energex’s TMU hence, the historic utilisation threshold was used as the forecast parameter.

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

#### Sources

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

#### Assumptions

The following assumptions were applied to derive the utilisation threshold statistics to HV feeders:

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

### Distribution transformers (including LV) network segments

Energex applied the same methodology to all distribution substation network segments, being the segments in the following AER segment groups:

* Distribution substations - CBD (including downstream LV network)
* Distribution substations - urban (including downstream LV network)
* Distribution substations - short rural (including downstream LV network)

#### Methodology

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

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

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

#### Sources

The Energex Plant RatingManual[[9]](#footnote-10).

#### Assumptions

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

* The network segment categorised as urban and rural were domestic customers
* Transformers classified in the CBD network segment were all substations for Commercial and Industrial customers.

## Relationship to historic utilisation

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

## Probability distribution

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

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

## Relationship to internal or external planning criteria

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

The Augex Model Handbook required that asset utilisation be provided based on normal cyclic ratings using 50% PoE loads[[10]](#footnote-11). However, Energex typically uses 50 PoE load forecasts with emergency ratings under outage conditions and uses 10% PoE load forecasts with normal cyclic ratings for normal conditions. These differences were taken into account when calculating the asset utilisation parameters.

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

## Verification of parameters

Energex considers that the methodology applied and the assumptions made are suitable for use in the Augex model for the following reasons:

* Parameters provided were commensurate with the network average approach implemented in the Augex model.
* The data used for the calculation of the parameters was sourced from business as usual systems used by Energex to plan network augmentation. The data in these systems is reviewed on a regular basis by the network capital strategy and planning group.
* Parameters were calculated in accordance with the Augex Model Handbook guidelines.

# Capacity factors

The AER requires Energex to provide a capacity factor that is used to define the amount of additional capacity that is added to the system in the Augex model. Where actual historical data is not available, the AER allows the derivation of the capacity factor from the normal practices of network planning or policy decisions to increment capacity in standard steps. The capacity factor must be greater than zero[[11]](#footnote-12).

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

The Capacity factor represents the capacity added, as a percentage, of the capacity of the existing network segment being augmented[[12]](#footnote-13). The formula for calculating the capacity factor is specified by the AER and is shown below:

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

Where:

* *Capacity Added* is the amount of capacity added to the network through new assets being installed
* *Capacity Requiring Augmentation* is the amount of capacity provided by the asset currently on the network which requires augmentation.

## Methodology, data sources and assumptions

### Sub-transmission network segments

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

* Sub-transmission lines
* Sub-transmission substations and sub-transmission switching stations
* Zone substations

A different methodology was applied to the derivation of forecast and actual parameters, as set out below.

#### Forecast parameter methodology

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

**Single radial feeder**

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

Figure 1 - Single radial feeder showing Augex augmentation

Existing

Augex model Augmentation

**Double radial feeder**

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

Figure 2 - Double radial feeder variations showing Augex augmentation

Existing

Augex model augmentation

**Triple mesh feeder**

Augex model augmentation involves connecting a fourth feeder in parallel between the two substations. Figure 3 shows the various arrangements of this topology that are included in this network segment and how these segments would be augmented.

Figure 3 - Triple mesh feeder variations showing Augex model augmentation

Various network segment topologies

Augex model augmentation

**Mesh/complex feeders**

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

Figure 4 - Mesh feeder variations showing Augex model augmentation

Example of mesh feeder

arrangement

Example of mesh feeder

Augex model augmentation

**Single transformer substations**

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

**Double transformer substations**

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

**Triple transformer substations**

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

#### Historical parameter methodology

A sample of 64 Planning Approval Reports was reviewed to establish the asset utilisation at the time of augmentation for the network segments of sub-transmission lines, sub-transmission substation, and zone substation. The sample size for each network segment is shown in Table 7‑1. The list of projects reviewed contained projects with project expenditure greater $5 million that were commissioned between 2009/10 and 2013/14.

Table 8‑1 - Review of past projects

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

#### Sources

Forecast capacity added was sourced from Energex’s Network Building Blocks[[13]](#footnote-14). This manual includes standard capacities for sub-transmission network assets.

Historical capacity added was sourced from planning approval reports.

#### Assumptions

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

### HV Feeder network segments

#### Forecast and historic parameter methodology

Energex undertook a review of 98 historical HV feeder augmentation projects to determine the capacity factors, and capacity added through these projects, at the time of replacement. Energex utilised historic capacity factor data for HV feeder network segments, where sufficient historic data was available.

The sample size for each network segments is shown in Table 8‑2. Projects included in the review consisted of projects commissioned between 2008 and 2013 where the project cost was greater than $500,000 and where one or more of the following system events were logged by NetPlan:

* 11 kV Load transfer
* 11 kV feeder rating change
* New 11 kV feeder

Table 8‑2 - Review of past projects

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

#### Sources

The NetPlan database was used to provide historic augmentation capacity.

#### Assumptions

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

### Distribution transformers (including LV) network segments

Energex applied the same methodology distribution transformers and low voltage network segments, being the network segments in the following AER segment groups:

* Distribution substations - CBD (including downstream LV network)
* Distribution substations - urban (including downstream LV network)
* Distribution substations - short rural (including downstream LV network)

#### Forecast and historic parameter methodology

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

#### Sources

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

#### Assumptions

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

## Relationship to historic augmentation

The calculation of capacity factor was heavily dependent on the existing asset, network configuration and drivers of augmentation.

Historic and forecast sub-transmission capacity factors can vary significantly due to:

* Small sample size of historical projects in each network segment
* Large variation in ratings of existing feeders
* Changes in security standards

For HV feeders, distribution substations and LV networks historic capacity factors have been used as the forecast parameters.

## Possibility of double counting

The possibility of double counting the capacity factors was minimised by clearly defining network segments (as set out in section 2.2) and ensuring that the inputs into capacity factor only included those associated with the network segment.

## Verification of parameters

Energex considers that capacity factors are a reasonable estimates for each network segment the following reasons:

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

# Augmentation unit cost

The AER requires Energex to provide an *augmentation unit cost* used to define the cost of additional capacity that is added to the system through the Augex model. The term *augmentation unit cost* is italicised in this section to indicate the unit costs derived for the purposes of the Augex model, as opposed to project and program estimates derived by Energex as part of its normal augmentation planning processes.

In order to calculate the augmentation unit cost for each network segment the following process was applied:

* Each project was assigned to an Augex model network segment.
* Cost and capacity added for each asset (or project for historical data) was then used to calculate the augmentation unit cost per MVA for that asset.
* The augmentation unit cost per MVA for a network segment was the average augmentation cost per MVA for all of the assets within the network segment.

Energex developed a generic unit cost for each network segment through its estimating system.

## Methodology, data sources and assumptions

### Sub-transmission and zone substation network segments

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

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

#### Forecast methodology

To cater for the network average nature of the network segments, 12 separate generic project scopes were developed and assigned a unit cost and capacity. The project types and high level scopes of work are set out in Table 9‑1.

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

Table 9‑1 - Project scopes overview

| Project type | Overview of key scope items |
| --- | --- |
| 110/132 kV SCCT OH line 180MVA  | 13 km of feeder with 2 x feeder bays (one at each sub), including all civil works |
| 110/132 kV SCCT UG line 240MVA | 3.5 km of feeder with 2 x feeder bays (one at each sub), including all civil works |
| 33 kV SCCT OH line 40MVA | 9 km of feeder and 1 x feeder bay, including all civil works |
| 33 kV SCCT UG line 40MVA | 4 km of feeder and 1 x feeder bay, including all civil works |
| Rural Zone sub upgrade 33/11 (8MVA) | Skid substation, including all civil works, 4km OH 11kV feeder works and 2km OH 33kV feeder works |
| Urban Zone Sub upgrade 33/11 (25MVA) | 2nd module, including all civil works, 2 km OH 11 kV feeder works, 2km UG 11kV feeder works, 1 km UG DCCT 33 kV feeder works and 33 kV feeder tail cutover |
| Urban zone Sub upgrade 110/11 (30MVA) | 30MVA 110/11kV transformer, 110 kV and 11 kV ID bus (masonry building), including all civil works, 4km OH 11kV feeder works and 110 kV UG feeder tails cutover |
| Rural zone Sub upgrade 110/11 (30 MVA) | 30 MVA 110/11kV transformer, 110 kV OD and 11kV ID prefab bus, including all civil works, 4km OH 11kV feeder works, 110 kV OH feeder tails cutover |
| Urban zone Sub upgrade 110/11 (60 MVA) | 60 MVA 110/11/11kV transformer, 110 kV and 11kV ID bus (masonry building), including all civil works, 4km UG 11kV feeder works, 110 kV UG feeder tails cutover |
| Urban Bulk Sub upgrade 110/33 (80 MVA) | 80 MVA 110/33 kV transformer, 110kV and 33 kV ID bus (masonry building), including all civil works, 110 kV and 33 kV UG feeder tails cutover |
| Rural Bulk Sub upgrade 110/33 (80 MVA) | 80 MVA 110/33 kV transformer, 110 kV OD and 33kV ID prefab bus, including all civil works, 110 kV and 33 kV OH feeder tails cutover |
| Urban Bulk Sub upgrade 110/33 (120 MVA) | 120 MVA 110/33 kV transformer, 110 kV and 33 kV ID bus (masonry building), including all civil works, 110kV and 33 kV UG feeder tails cutover |

#### Historical methodology

A sample of 64 Planning Approval Reports was reviewed for the network segments of sub-transmission lines, sub-transmission substation, and zone substation to estimate the historic *augmentation unit cost*. The sample size for each network segment is shown in Table 9‑2. The list of projects reviewed contained projects with project expenditure greater $5 million that were commissioned between 2009/10 and 2013/14.

Table 9‑2 - Review of past projects

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

#### Sources

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

Historic parameters were recorded from Planning Approval Reports.

#### Assumptions

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

### HV feeder network segments

#### Forecast methodology

The list of projects developed and high level scopes of work are shown in Table 9‑3. These scopes were apportioned in terms of capacity added and cost contributions to each Augex model network segments for the purpose of deriving unit costs.

Table 9‑3 - Project scopes overview

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

#### Historical methodology

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

* 11 kV Load transfer;
* 11 kV feeder rating change; or
* New 11 kV feeder.

HV feeder projects include tie feeders that enable transfer between feeders but do not add to the network capacity for the purposes of the Augex model. This issue was recognised by the AER in its Augmentation Model Handbook[[14]](#footnote-15).

#### Sources

Standard cost estimation was sourced from the Ellipse Estimation Systems and modules, particularly the Compatible Units and Estimation Modules. The Plant Rating[[15]](#footnote-16) Manual was used to identify typical additional capacity added corresponding with each of the project scopes.

#### Assumptions

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

### Distribution substations including LV network segments

#### Forecast methodology

The methodology applied to forecast unit costs for distribution substation and LV network segments used a standard cost estimate generated through the Ellipse Estimation System. The cost per MVA for each segment was determined by taking the weighted average cost per MVA installed for each Standard Estimate under the applicable network segment. Table 9‑4 sets out the standard estimates applicable for each network segment.

Table 9‑4 – Standard Estimates overview

|  Network Segment | Standard Estimate Description |
| --- | --- |
| ≤25kVA Transformers | Upgrade Transformer from 25kVA 3 Phase TO 100kVA 3 Phase |
| Upgrade Transformer from 25kVA 3 Phase TO 200kVA 3 Phase |
| Upgrade Transformer from 25kVA 3 Phase TO 315kVA 3 Phase |
| Upgrade Transformer from 25kVA 3 Phase TO 63kVA 3 Phase |
| 30kVA to 63kVA Transformers | Upgrade Transformer from 63kVA 3 Phase TO 100kVA 3 Phase |
| Upgrade Transformer from 63kVA 3 Phase TO 200kVA 3 Phase |
| Upgrade Transformer from 63kVA 3 Phase TO 315kVA 3 Phase |
| 75kVA to 100kVA Transformers | Upgrade Transformer from 100kVA 3 Phase TO 200kVA 3 Phase |
| Upgrade Transformer from 100kVA 3 Phase TO 315kVA 3 Phase |
| 150kVA to 315kVA Transformers | Upgrade Transformer from 200kVA 3 Phase TO 315kVA 3 Phase |
| Upgrade Padmount Transformer from 315kVA 3 Phase TO 500kVA 3 Phase RECTANGLE |
| Upgrade Padmount Transformer from 315kVA 3 Phase TO 500kVA 3 Phase SQUARE |
| Upgrade Padmount Transformer from 315kVA 3 Phase to 750kVA 3 Phase SQUARE |
| Upgrade Padmount Transformer from 315kVA 3 Phase TO 750kVA 3 Phase RECTANGLE |
| Upgrade Padmount Transformer from 315kVA 3 Phase TO 1000kVA 3 Phase RECTANGLE |
| Upgrade Padmount Transformer from 315kVA 3 Phase TO 1000kVA 3 Phase SQUARE |
| 500kVA Transformers | Upgrade Transformer from 500kVA 3 Phase TO 750kVA 3 Phase SQUARE |
| Upgrade Transformer from 500kVA 3 PH TO 750kVA 3 Phase RECTANGLE |
| Upgrade Transformer from 500kVA 3 Phase TO 1000kVA 3 Phase SQUARE |
| Upgrade Transformer from 500kVA 3 Phase TO 1000kVA 3 Phase RECTANGLE |
| 750kVA Transformers | Upgrade Transformer from 750kVA 3 Phase TO 1000kVA 3 Phase RECTANGLE |
| Upgrade Transformer from 750kVA 3 Phase TO 1000kVA 3 Phase SQUARE |
| 1000kVA Transformers | Upgrade Ground Transformer from 1000kVA 3 Phase TO 1500kVA 3 Phase |
| 1500kVA Transformers | Install a New 11kV – Ground Transformer 1500kVA (Dry Type) |

#### Historical methodology

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

#### Sources

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

Standard cost estimation was sourced from the Ellipse Estimation Systems and modules, particularly the Compatible Units and Estimation Modules. The Plant Rating[[16]](#footnote-17) Manual was used to identify typical additional capacity added corresponding with each of the project scopes.

#### Assumptions

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

## Relationship to historical augmentation

### Sub-transmission network segments

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

* surroundings (population density).
* environments (imposing requirements relating to vegetation and wildlife).
* traffic conditions (imposing requirements relating to traffic control, under-boring and time of day where works can be carried out).
* soil conditions, specific council guidelines and community requirements (imposing requirements relating to undergrounding).
* changes in legislation and external approval requirements over time.
* Route length which the Augex model is not able to account for (it only considers unit cost as $/MVA). Assumptions of typical route length for sub-transmission lines are set out in Table 2‑2 of section 2.2.

Energex takes all of these factors into account by producing bottom-up estimate for each sub-transmission projects as part of the normal planning process.

### HV feeders

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

### Distribution substations including LV

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

## Possibility of double counting

The possibility of double counting the *augmentation unit cost* was minimised by clearly defining network segments (as set out in section 2.2) and ensuring that the inputs into *augmentation unit cost* only included those associated with the network segment.

## Verification of parameters

Energex considers that *augmentation unit cost* are a reasonable estimate for each network segment the following reasons:

* *augmentation unit cost* provided were commensurate with the network average approach implemented in the Augex model.
* The data used for the calculation of the parameters was sourced from business as usual systems used by Energex to plan network augmentation. The data in these systems is reviewed on a regular basis by the network capital strategy and planning group.
* Parameters were calculated in accordance with the Augex Model Handbook guidelines.

# Unmodelled augmentation

The AER acknowledges that not all projects that provide additional capacity to the network are caused by increasing demand and therefore should not be forecast using the Augex model[[17]](#footnote-18). Energex allocated a range of projects and programs to the unmodelled augmentation categories in the Augex model.

## Primary drivers

There are four primary drivers of capex projects and programs allocated to unmodelled augmentation and these are discussed in the following sections, being: and these are discussed in the following sections.

* Compliance projects and programs
* Reliability projects and programs
* Power quality projects and programs
* Strategic land and easements

### Compliance projects and programs

Energex compliance augmentation is driven by a range of compliance projects and programs which impose obligations relating to:

* Voltage constraints
* Highway crossings
* Fault level constraints
* Flood and bushfire events
* Protection limitations.

Energex considers that, in addition to the primary drivers of this capex, there is a secondary relationship to maximum demand and/or utilisation.

### Reliability projects and programs

Energex must meet Minimum Service Standard targets set out in its Distribution Authority (DA). Network performance has improved during the current regulatory control period and performance currently exceeds these targets. There are no augmentation projects planned to improve the average performance of the network.

The DA also requires Energex to put in place a program to improve the reliability of the worst performing 11 kV feeders. Reliability expenditure during the 2015-20 regulatory control period will be targeted at addressing feeders that meet the worst performing feeder criteria set out in the DA.

Energex considers that, in addition to the primary drivers of this capex, there is not any secondary relationship to maximum demand and/or utilisation.

More detail regarding the network reliability expenditure forecast is provided in Energex’s Regulatory Proposal and Reliability Strategic Plan.

### Power quality projects and programs

The proposed power quality program seeks to expand the monitoring and reporting programs established during the current regulatory control period. This will drive a targeted LV remediation program to address voltage non-compliances.

Energex considers that, in addition to the primary drivers of this capex, there is not any secondary relationship to maximum demand and/or utilisation.

More detail regarding the power quality expenditure forecast is provided in Energex’s Regulatory Proposal and Power Quality Strategic Plan.

### Strategic land and easement projects and programs

The land and easements forecast was developed based on the need for future substation sites and overhead line routes identified through the network strategic planning process.

Energex considers that, in addition to the primary drivers of this capex, there is not any secondary relationship to maximum demand and/or utilisation.

## Proportion of augmentation capex

Table 10‑1 shows the proportion of forecast expenditure required to address limitations that were not modelled by the Augex model.

Table 10‑1 Unmodelled expenditure

| **Expenditure (%)** | 2016 | 2017 | 2018 | 2019 | 2020 |
| --- | --- | --- | --- | --- | --- |
| Compliance | 54% | 42% | 48% | 27% | 29% |
| Reliability | 13% | 9% | 11% | 14% | 16% |
| Power Quality | 5% | 4% | 5% | 14% | 16% |
| Land & Easements | 3% | 4% | 5% | 9% | 10% |

## Program outcomes

Table 10‑2 provides secondary outcomes of the unmodelled expenditure on network capability and customer service levels.

Table 10‑2 Secondary program outcomes

| **Outcome** | Increase in the capability of the network to supply customer demand at similar service levels | **Improvement in service levels for a similar customer demand level** |
| --- | --- | --- |
| Compliance |  | x |
| Reliability | x | x |
| Power Quality | x | x |
| Land & Easements | x | x |

It should be noted that reliability projects will specifically target the worst performing 11 kV feeders as required by the DA. These projects were not forecast to impact the average performance of the network.

# Unique factors driving augmentation

## Distribution Authority

From 1 July 2014 new obligations under the Energex Distribution Authority (DA) required Energex to plan and develop its supply network in accordance with good electricity industry practice. These obligations impact augmentation work by having regard to the value that end users place on the quality and reliability of the service they receive.

Whilst the DA obligations primarily impact Energex’s unmodelled augmentation expenditure programs such reliability projects, Energex relies on the availability of 33 kV and 11 kV transfers to restore supplies in the timeframes set required by the safety net targets.

The new obligations are set out in more detail in the following subsections.

### Minimum service standards

This provides a standard against which feeder performance is assessed by feeder type. Energex must use all reasonable endeavours to ensure it does not exceed the SAIDI and SAIFI targets applicable to each feeder type set out in Schedule 2 of the DA.

### Safety net

The purpose of the safety net is to mitigate the risk of high impact low probability network outages. Energex must design, plan and operate the network to achieve the safety net targets as set out in Schedule 3 of the DA.

### Improvement programs

The purpose of the improvement programs is to enable customers with the worst reliability outcomes to benefit from tailored network improvements. Specifically, Energex is required to improve 11kV feeders where their performance is ranked in the worst 10% of 11 kV feeders, based on a three year average and greater than 150% of the performance target for the feeder category.

### Impact on maximum utilisation

Meeting the safety net targets set out in the DA relies on 11 kV feeder ties to support sub-transmission or substation capacity (inter substation transfers only). The target maximum utilisation takes into account the ability of transferring loads from adjacent feeders and identifies limits transferring between substations on feeders, consistent with Energex’s planning standard. 11 kV projects associated with improving the tie capacity between substations have been separately identified in the program of work.

# Compliance checklist

Table 12‑1 sets out the requirements of Reset RIN Schedule 1 relating to Augex modelling and the section of this document addressing each requirement.

Table 12‑1 Compliance checklist

|  |  |  |
| --- | --- | --- |
| RIN Clause | Description | Section Reference |
| 7.1  | Any instructions in this Notice relating to the Augex model must be read in conjunction with the Augex model guidance document. | 1.2 |
| 7.2(a)(i)(A) | Separately for sub-transmission lines, sub-transmission and zone substations, HV feeders and distribution substations, Energex must explain how it prepared the maximum demand data (weather corrected at 50 per cent probability of exceedance), including where relevant, explanations of each of:…how this value relates to the maximum demand that would be used for normal planning purposes | 3.2 |
| 7.2(a)(i)(B) | … whether it is based upon a measured value, and if so, where the measurement point is and how abnormal operating conditions are allowed for | 3.3 |
| 7.2(a)(i)(C) | … whether it is based on estimated (rather than actual measured) demand, and if so, the basis of this estimation process and how it is validated | 3.3 |
| 7.2(a)(i)(D) | …the relationship of the values provided to raw unadjusted maximum demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year | 3.4 |
| 7.2(a)(ii)(A) | Separately for sub-transmission lines, sub-transmission and zone substations, HV feeders and distribution substations, Energex must explain how it determined the rating data, including where relevant:…the basis of the calculation of the ratings in that segment, including asset data measured and assumptions made | 4.1 |
| 7.2(a)(ii)(B) | …the relationship of these ratings with Energex’s approach to operating and planning the network. For example, if alternative ratings are used to determine the augmentation time, these should be defined and explained | 4.2 |
| 7.2(a)(iii) | Separately for sub-transmission lines, sub-transmission and zone substations, HV feeders and distribution substations, Energex must explain how it determined the growth rate data. This should clearly indicate how these rates have been derived from maximum demand forecasts or other load forecasts available to Energex  | 5.1 / 5.3 |
| 7.2(b)(i) | In relation to the capex-capacity regulatory template 2.4.6, Energex must explain the types of cost and activities covered. Clearly indicate what non-field analysis and management costs (i.e. direct overheads) are included in the capex and what proportion of capex these cost types represent | 6.1 |
| 7.2(b)(ii)(A) | In relation to the capex-capacity regulatory template 2.4.6, Energex must explain how it determined and allocated actual capex and capacity to each of the segment groups, covering:…the process used, including assumptions, to estimate and allocate expenditure where this has been required | 6.2 |
| 7.2(b)(ii)(B) | …the relationship of internal financial and/or project recording categories to the segment groups and process used | 6.2 |
| 7.2(b)(iii)(A) | In relation to the capex-capacity regulatory template 2.4.6, Energex must explain how it determined and allocated estimated/forecast capex and capacity to each of the segment groups, covering:…the relationship of this process to the current project and program plans | 6.3 |
| 7.2(b)(iii)(B) | …any other higher-level analysis and assumptions applied | 6.3 |
| 7.2(c)(i) | Describe the projects and programs Energex has allocated to the unmodelled augmentation categories, covering:… the proportion of unmodelled augmentation capex due to this project or program type | 10.2 |
| 7.2(c)(ii) | …the primary drivers of this capex, and whether in Energex’s view, there is any secondary relationship to maximum demand and/or utilisation | 10.3 |
| 7.2(c)(iii) | … whether the outcome of such a project or program, whether intended or not, should be an increase in the capability of the network to supply customer demand at similar service levels, or the improvement in service levels for a similar customer demand level | 10.3 |
| 7.2(d)(i)(A) | Separately for each network segment describe the network segment, including:…the boundary with other connecting network segments | 2.2  |
| 7.2(d)(i)(B) | …the main reasoning for the individual segment (e.g. as opposed to forming a more aggregate segment) | 2.2  |
| 7.2(d)(ii)(A) | Separately for each network segment explain the utilisation threshold statistics provided (i.e. the mean and standard deviation), including:…the methodology, data sources and assumptions used to derive the parameters | 7.1 |
| 7.2(d)(ii)(B) | …the relationship to internal or external planning criteria that define when an augmentation is required | 7.4 |
| 7.2(d)(ii)(C) | …the relationship to actual historical utilisation at the time that augmentations occurred for that asset category | 7.2 |
| 7.2(d)(ii)(D) | …Energex’s views on the most appropriate probability distribution to simulate the augmentation needs of that network segment | 7.3 |
| 7.2(d)(ii)(E) | …the process applied to verify that the parameters are a reasonable estimate of utilisation limit for the network segment | 7.5 |
| 7.2(d)(iii)(A) | Separately for each network segment, regarding the augmentation unit cost and capacity factor provided, provide an explanation of each of:…the methodology, data sources and assumptions used to derive the parameters | 8.1.1 / 8.1.2 / 8.1.39.1.1 / 9.1.2 / 9.1.3 |
| 7.2(d)(iii)(B) | …the relationship of the parameters to actual historical augmentation projects, including the capacity added through those projects and the cost of those projects | 8.2 / 9.2 |
| 7.2(d)(iii)(C) | …the possibility of double-counting in the estimates, and processes applied to ensure that this is appropriately accounted for (e.g. where an individual project may add capacity to various segments). | 9.3 / 8.3 |
| 7.2(d)(iii)(D) | …the process applied to verify that the parameters are a reasonable estimate for the network segment. | 8.4 / 9.4 |
| 7.2(e)(i) | Explain the factors Energex considers may result in different augmentation requirements for itself as compared to other NEM DNSPs. For each significant factor discussed, Energex must indicate relevant model segments and estimate the impact these factors will have on its augmentation levels and associated capex compared to other DNSPs. The explanation should clearly indicate those factors that may impact:… the maximum achievable utilisation of assets for Energex | 11.0 |
| 7.2(e)(ii) | … the likely augmentation project and/or cost | 11.0 |

1. AER augmentation model handbook, November 2013. [↑](#footnote-ref-2)
2. Energex, Plant Rating Manual, January 2008 [↑](#footnote-ref-3)
3. AER augmentation model handbook, November 2013, section 5 [↑](#footnote-ref-4)
4. Energex, Plant Rating Manual, January 2008 [↑](#footnote-ref-5)
5. AER augmentation model handbook, November 2013, section 4.2.1 and 5.1.6 [↑](#footnote-ref-6)
6. Energex, Plant Rating Manual, January 2008 [↑](#footnote-ref-7)
7. AER augmentation model handbook, November 2013, sections 3.2 and 4.2.2 [↑](#footnote-ref-8)
8. Energex Distribution Authority – Schedule 3 [↑](#footnote-ref-9)
9. Energex, Plant Rating Manual, January 2008 [↑](#footnote-ref-10)
10. AER augmentation model handbook, November 2013, sections 5.1.2 and 5.1.6 [↑](#footnote-ref-11)
11. AER augmentation model handbook, November 2013 [↑](#footnote-ref-12)
12. AER augmentation model handbook, November 2013, section 4.4.2 [↑](#footnote-ref-13)
13. Energex document 00303 – Standard Network Building Blocks, 2012 [↑](#footnote-ref-14)
14. Australian Energy Regulator, AER augmentation model handbook, November 2013 section 5.1.3 [↑](#footnote-ref-15)
15. Energex, Plant Rating Manual, January 2008 [↑](#footnote-ref-16)
16. Energex, Plant Rating Manual, January 2008 [↑](#footnote-ref-17)
17. Australian Energy Regulator, AER augmentation model handbook, November 2013 section 5.1.8 [↑](#footnote-ref-18)