Jemena Electricity Networks (Vic) Ltd

Jemena Electricity Networks (Vic) Ltd

Network Augmentation Planning Criteria

Technical Methodology, Inputs and Assumptions

TABLE OF CONTENTS

GLOSSARY

Term	Definition
constraint	A limitation on the capability of a network, load or a generating unit such that it is unacceptable to either transfer, consume or generate the level of electrical power that would occur if the limitation was removed.
contingency condition (or event)	Refers to the loss or failure of part of the network. An event affecting the power system that will be likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
deterministic method	Determines the need for augmentations using criteria that define the maximum permissible loading on assets, rather than by explicitly measuring customer outcomes
discounted cash flow (DCF) (analysis)	A valuation method that estimates the attractiveness of an investment opportunity. Discounted cash flow (DCF) analysis uses future free cash flow projections and discounts them to arrive at a present value, which is used to evaluate the investment potential.
energy-at-risk	The total energy that is at risk of not being supplied to customers.
expected unserved energy (EUE)	Refers to an estimate of the long-term, probability weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.
feeder continuous rating	The permissible maximum demand to which a conductor or cable may be loaded to on a continuous basis.
feeder cyclic rating	The permissible maximum demand to which a conductor or cable may be loaded on a daily basis for up to 90 consecutive days during the summer or winter period, taking into account the cyclic nature of the daily feeder load profile. Cable cyclic rating is typically equal to a multiple of 1.13 times the cable’s continuous rating. Overhead conductor cyclic rating is equal to the conductor’s continuous rating.
Jemena Electricity Networks (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 360,000 customers via an 6,900 kilometre distribution system covering north-west greater Melbourne.
load duration curve	Shows the amount of time (usually over a year or season) that demand was within a given percentage of the maximum demand (MD).
maximum demand (MD)	The highest amount of electrical power delivered, or forecast to be delivered, over a defined period (day, week, month, season or year) either at a connection point, or simultaneously at a defined set of connection points.

Term	Definition
maximum demand scenario	Refers to the possible (projected) maximum demand resulting from a given set of drivers (e.g. level of population and economic growth). Scenarios usually examine the possible maximum demand outcomes resulting from high, medium and low growth, with a medium growth scenario often expected to be the most likely.
megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.
network	The apparatus, equipment, plant and buildings used to convey, and control the conveyance of, electricity to customers (whether wholesale or retail) excluding any connection assets. In relation to a Network Service Provider, a network owned, operated or controlled by that Network Service Provider.
network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
network capacity	Refers to the network's ability to transfer electricity to customers.
non-network alternative	A means by which an identified need can be fully or partly addressed other than by a network option.
overhead lines maximum safe loading limit on HV network (summer)	A maximum load limit on HV network under system normal operating condition determined under various environmental conditions where the conductor operating temperature is likely to exceed 100ºC where the conductor annealing effect is accelerated to an unacceptable level or statutory clearance limit is likely to be infringed.
planning criteria	The methodologies, inputs and assumptions that must be followed when undertaking technical and economic analysis to predict emerging power transfer limitations.
power quality	Has the same meaning as 'quality of supply'. It is the measure of the ability of the distribution system to provide supply that meets the quality requirements set out in the Victorian Electricity Distribution Code of Practice (VEDCoP) and National Electricity Rules (NER).
probability of exceedence (POE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year: • 50% PoE maximum demand is the level of annual demand that is expected to be exceeded one year in two. • 10% PoE maximum demand is the level of annual demand that is expected to be exceeded one year in ten.

Term	Definition
probabilistic method	• directly measures customer (economic) outcomes associated with future network limitations • provides a thorough cost-benefit analysis when evaluating network or non-network augmentation options, and • estimates expected unserved energy (EUE), which is defined in terms of megawatt hours (MWh) per annum, and expresses this economically by applying a value of customer reliability ($/MWh).
quality of supply	The measure of the ability of the distribution system to provide supply that meets the quality requirements set out in the Victorian Electricity Distribution Code of Practice (VEDCoP) and National Electricity Rules (NER).
Regulatory Investment Test for Distribution (RIT-D)	A test administered by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for consultation on distribution network investments in the National Electricity Market (NEM).
reliability of supply	The measure of the ability of the distribution system to provide supply to customers.
service target performance incentive scheme (STPIS)	A scheme established and amended by the Australian Energy Regulator (AER) that is designed to provide incentives for each network service provider to maintain or improve network service performance.
System Average Interruption Duration Index (SAIDI)	The total minutes, on average, that a customer could expect to be without electricity over a specific period of time, calculated as the sum of the duration of each customer interruption (in minutes), divided by the total number of connected customers averaged over the year.
System Average Interruption Frequency Index (SAIFI)	The number of occasions per year when each customer could, on average, expect to experience an unplanned interruption, calculated as the total number of customer interruptions, divided by the total number of connected customers averaged over the year. Unless otherwise stated, SAIFI excludes momentary interruptions.
system normal	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices.
underground cable maximum safe loading limit	A maximum load limit of the HV underground cable determined to be the cyclic rating under system normal operating condition.
value of customer reliability (VCR)	Represents the dollar value customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted).

 Public—31 January 2025 © Jemena Electricity Networks (Vic) Ltd

Term	Definition
10POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50POE condition (summer)	Refers to an average daily ambient temperature of 29.4ºC, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50POE and 10POE condition (winter)	50POE and 10POE condition (winter) are treated the same, referring to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC.

ABBREVIATIONS

Abbreviation	Expanded Name
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AS	Australian Standards
COWP	Capital and operational work plan
DAPR	Distribution Annual Planning Report
DNSP	Distribution Network Service Provider
E@R	Energy-at-risk
EUE	Expected Unserved Energy
JEN	Jemena Electricity Networks
MD	Maximum Demand
NAMP	Network asset management plan
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
POE	Probability of Exceedence
RIT-D	Regulatory Investment Test for Distribution
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission Network Service Provider
VCR	Value of Customer Reliability
VEDCoP	Victorian Electricity Distribution Code of Practice

Public—31 January 2025 © Jemena Electricity Networks (Vic) Ltd

OVERVIEW

Jemena Electricity Networks (JEN) is responsible for planning and developing its distribution network. It is also responsible for planning and directing the augmentation of its connection points with the transmission network, which are owned and maintained by the relevant transmission network service provider (TNSP). These planning activities are aimed at prudently and efficiently managing customer service levels and power quality requirements in the face of growth in customer demand for electricity. Investments of this nature are commonly referred to as augmentation of the network.

A number of regulatory instruments define JEN's network augmentation obligations and affect planning methodologies and assumptions. The regulatory instruments that set the power quality obligations for JEN's network operations include JEN's Electricity Distribution Licence, the Victorian Electricity Distribution Code of Practice (VEDCoP) and National Electricity Rules (NER).

Network Augmentation Objectives

Consistent with the augmentation obligations defined in the regulatory instruments, in particular the National Electricity Objective set out in the National Electricity Law and the capital expenditure objectives set out in Clause 6.5.7 (a) of the NER, JEN's distribution system planning objectives are:-

- To provide safe, cost effective, efficient, reliable supply that meets target levels of performance;
- To maximise utilisation of existing assets; and
- To determine the most cost-effective means of developing the network to meet future loading requirements and customer needs.

A project aimed at alleviating a distribution system constraint should proceed if it minimises the cost to customers, having regard to the:

- Relative costs and benefits, including any change in supply reliability, of network augmentation and non-network alternatives to the augmentation;
- Uncertainty of assumptions that must necessarily be made in the decision analysis;
- Total asset life cycle costs; and
- Need to comply with environmental and land-use planning standards, health and safety standards, and applicable technical standards.

Network Augmentation Drivers

There are four key drivers for network augmentation addressed by the network planning process:-

- Load growth – The growing demand for electricity (typically over the summer period), whether through new customers connecting, or existing customers increasing their load that may overload our network;
- Safety – Overloaded electricity plant and equipment may pose a significant health and safety risk;
- Regulatory compliance – the required work to comply with all applicable regulatory obligations or requirements as defined in regulatory instruments, including quality and security of supply;
- Supply reliability – the planning level to maintain supply reliability. As a last resort, plant overloads are avoided by shedding supply to customers, thereby causing supply interruptions.

These drivers are consistent with the network augmentation obligations defined in the regulatory instruments, in particular the capital expenditure objectives set out in Clause 6.5.7 (a) of the NER.

Planning approach

The general approach in developing this planning criteria, that JEN considers meeting the network augmentation objectives and drivers, are:

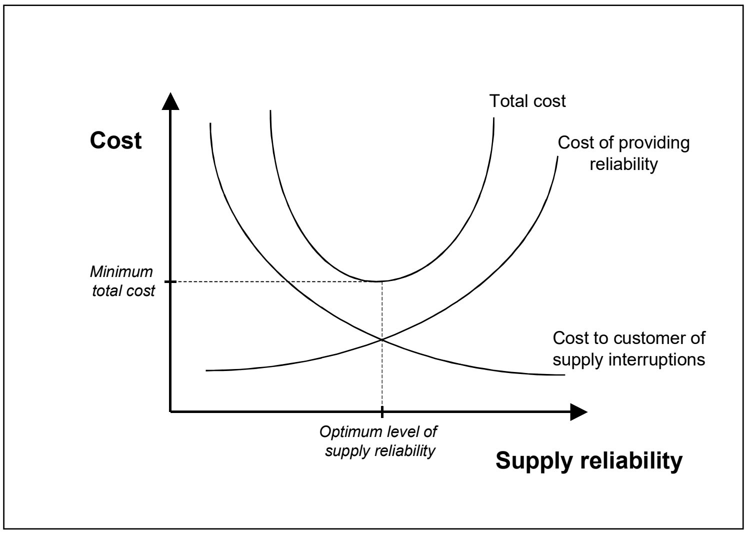
- For meshed network, as in the case of transmission connection points, sub-transmission lines and zone substations, a probabilistic method is adopted where the load is allowed to exceed the N-1 cyclic rating, and in some cases the system normal (N) rating, and the network is only augmented when it is economical. However, to maintain the safety of the distribution system, post-contingent and pre-contingent levels are defined. Refer to Schedule 1 for details.
- For high-voltage radial network, a probabilistic method is adopted for forecast load up to maximum safe loading limit. For forecast load above maximum safe loading limit, a deterministic method is adopted. This approach is to promote the efficient investment in additional network (or non-network) capacity while maintaining the safety of the distribution system. Effectively, maximising the utilisation of existing assets without infringing on the safety of the distribution system.
- For distribution substations (which is considered a radial network), a deterministic method is adopted using the maximum permissible loading limit of the asset under system normal state. The criteria are set to approximate the prudent timing for when additional network (or non-network) capacity is required, such that it maximises the utilisation of existing assets without infringing on the safety of the distribution system.

The planning standards and criteria applied in network development are a significant determinant of network-related costs. Costs associated with distribution network facilities can be considered to be comprised of two parts:

- The direct cost of the service (as reflected in network use of system charges and the costs of losses); and
- Indirect costs borne as a consequence of supply interruptions caused by network faults, that is, network reliability.

In developing and applying this planning criteria, JEN aims to develop distribution network assets in an efficient manner that minimises the total (direct plus indirect) life cycle cost of network service borne by customers. This basic concept is illustrated in Figure OV-1.

Figure OV-1: Balancing the direct cost of service and the indirect cost of interruption



In addition, JEN's distribution network investment decisions aim to minimise the cost to customers, having regard for the costs and benefits of non-network alternatives to augmentation. Such alternatives include, but are not necessarily limited to, demand-side management and embedded generation.

This planning criteria document serves as an internal procedure that defines the methodologies, inputs and assumptions that must be followed when undertaking various stages of technical and economic analysis. For information about the actual inputs and assumptions, refer to Schedule 1.

1. INTRODUCTION

Jemena Electricity Networks (JEN) is responsible for planning and developing its distribution network. It is also responsible for planning and directing the augmentation of its connection points with the transmission network[1], which are owned and maintained by the relevant transmission network service provider (TNSP). These planning activities are aimed at prudently and efficiently managing customer service levels and power quality requirements in the face of growth in customer demand for electricity.

Investments of this nature are commonly referred to as augmentation of the network. The augmentation planning task involves various stages of technical and economic analysis. This analysis is aimed at predicting emerging constraints on the transfer of electricity through the network that affect customer service.

This document serves as an internal procedure that defines the methodologies, inputs and assumptions that must be followed when undertaking this analysis. Taken together, these inputs and assumptions are commonly referred to within the industry as planning criteria.

1.1 DOCUMENT OBJECTIVE

This document's objective is to ensure the consistent performance of the analysis underpinning JEN's augmentation plans, using a methodology and assumptions that accord with the regulatory regime and JEN's corporate objectives. To achieve this, the document serves as a high-level internal technical criteria that defines the:

- methodology for deciding whether to invest (and optimal timing for investment) in additional network capacity or non-network alternatives,
- planning criteria for applying this methodology, and
- sources of data when preparing the inputs and assumptions.

Exclusions

The broader aspects of network planning are not covered by this procedure, including:

- load forecasting,
- cost estimating,
- consumer and demand-side engagement,
- internal and external joint planning, and
- JEN's governance processes.

1 Refer to JEN's distribution licence for these obligations.

1.2 REQUIREMENTS FOR APPLYING THE PLANNING CRITERIA

When applying these criteria:

- The personnel responsible for planning the JEN distribution network must apply the planning criteria (refer to Schedule 1).
- Any projects for inclusion in a Distribution Annual Planning Report (DAPR) and JEN's plans, such as the Network Asset Management Plan (NAMP) and Capital and Operational Work Plan (COWP), must be validated against these planning criteria.
- Schedule 1 must be reviewed prior to developing plans that underpin a regulatory proposal to the Australian Energy Regulator (AER).

1.3 DOCUMENT REVIEW

This document, including the underlying methods, inputs and assumptions, must be reviewed for suitability at least every five years, or less if circumstances require. The review should at least cover:

- consideration of customer and regulator expectations,
- network and non-network innovation and technology advancement,
- recent changes to the load profile and equipment outages that may affect the assumptions,
- changes to the sources of inputs, and
- changes in legal and regulatory requirements.

Public—31 January 2025 © Jemena Electricity Networks (Vic) Ltd

2. REGULATORY OBLIGATIONS AND JEN'S PLANNING APPROACH

2.1 RELEVANT REGULATORY INSTRUMENTS AND OBLIGATIONS

A number of regulatory instruments define JEN's network augmentation obligations and affect planning methodologies and assumptions. Important points relevant to the planning methodologies include the following:

- There are no strict compliance obligations in terms of reliability.
- JEN's Electricity Distribution Licence, the Victorian Electricity Distribution Code of Practice (VEDCoP) and National Electricity Rules (NER) are the regulatory instruments that set the power quality obligations for JEN's network operations.
- The regulatory regime oblige JEN to make the most economical capacity investments in terms of their effect on customer outcomes.
- The Regulatory Investment Test for Distribution (RIT-D) is a consultation process that sets the analytical requirements for projects subject to a RIT-D, particularly with regard to economic analysis to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market.

Below are extracts of the important points from each of the regulatory instruments relevant to defining the planning methodologies and criteria.

2.1.1 NATIONAL ELECTRICITY LAW

JEN's distribution licence requires it to comply with all applicable laws. One of these laws that JEN must comply with is the National Electricity Law (NEL). The NEL is contained in a Schedule to the National Electricity (South Australia) Act 1996 and has been adopted by each of the participating jurisdictions.

The National Electricity Objective, set out in the NEL, is to -

"promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system; and

(c) the achievement of targets set by a participating jurisdiction -
   a. for reducing Australia's greenhouse gas emissions; or
   b. that are likely to contribute to reducing Australia's greenhouse gas emissions."

2.1.2 NATIONAL ELECTRICITY RULES

The NER (Chapter 5 - Part B - Network Planning and Expansion) imposes minimum planning horizon and reporting obligations, particularly with regard to the RIT-D and Distribution Annual Planning Report (DAPR)).

Clause 6.5.7 (a) of the NER also outlines the four capital expenditure objectives. These objectives are relevant to the planning methodologies and are as follows:

"*A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):*

> *(1) meet or manage the expected demand for standard control services over that period;*
>
> *(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
>
> *(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:*
>
>> *(i) the quality, reliability or security of supply of standard control services; or*
>>
>> *(ii) the reliability or security of the distribution system through the supply of standard control services,*
>>
>> *to the relevant extent:*
>>
>> *(iii) maintain the quality, reliability and security of supply of standard control services; and*
>>
>> *(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and*
>
> *(4) maintain the safety of the distribution system through the supply of standard control services; and*
>
> *(5) contribute to achieving emissions reduction targets through the supply of standard control services"*

2.1.3 VICTORIAN ELECTRICITY DISTRIBUTION CODE OF PRACTICE (VEDCOP)

Clause 19.2 explanatory note of the VEDCoP *defines elements of good asset management which are designed to encourage innovation in the provision of* ***distribution*** *services and not prescribe* ***distributors'*** *practices in detail. The* ***Commission*** *may, however, undertake detailed examination of a* ***distributor's*** *practices if there is a substantial decline in the* ***quality*** *or* ***reliability of supply****, or evidence of a significant risk that such a decline may occur in the future when compared to the licensee's historical performance and its performance targets.*

Clause 19.2 of the VEDCoP requires that JEN, as a distributor, must use its best endeavours to[2]:

a. *assess and record the nature, location, condition and performance of its distribution system assets*
b. *develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets and plans for the establishment and augmentation of transmission connections:*
   - *to comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in this Code*
   - *to minimise the risks associated with the failure or reduced performance of assets*
   - *in a way which minimises costs to customers taking into account distribution losses*
c. *develop, test or simulate and implement contingency plans (including where relevant plans to strengthen the security of supply) to deal with events which have a low probability of occurring, but are realistic and would have a substantial impact on customers.*

[2] Electricity Distribution Code of Practice | Essential Services Commission

Clause 13.3 of the VEDCoP also requires that JEN, as a distributor, *must use best endeavours to meet targets* ***determined by the AER in the current distribution determination*** *and targets published under clause 13.2 and otherwise meet reasonable* ***customer*** *expectations of* ***reliability of supply****.*

2.2 AUSTRALIAN STANDARDS

In addition to the various regulatory instruments, JEN also refers to the Australian Standards to define its planning inputs and assumptions, including the major plant asset ratings. These ratings are used to define the operating limits within the planning methodologies.

2.3 JEN'S PLANNING APPROACH

2.3.1 PLANNING OBJECTIVES AND DRIVERS

2.3.1.1 Network Augmentation Objectives

JEN regularly reviews its planning philosophy and system development directions to ensure network performance and risk is maintained at appropriate levels as demanded by customers and regulators.

Consistent with the augmentation obligations defined in the regulatory instruments as outlined in Section 2.1, JENs distribution system planning objectives are:-

- To provide safe, cost effective, efficient, reliable supply that meets target levels of performance;
- To maximise utilisation of existing assets; and
- To determine the most cost-effective means of developing the network to meet future loading requirements and customer needs.

A project aimed at alleviating a distribution system constraint should proceed if it minimises the cost to customers, having regard to the:

- Relative costs and benefits, including any change in supply reliability, of network augmentation and non-network alternatives to the augmentation;
- Uncertainty of assumptions that must necessarily be made in the decision analysis;
- Total asset life cycle costs; and
- Need to comply with environmental and land-use planning standards, health and safety standards, and applicable technical standards.

Distribution system planning is integrated and optimised to meet the demands of load growth and renewal of the ageing, poor performing parts of the network. It includes a commitment to maximise utilisation of assets and to use non-network solutions where they are cost effective. The investment planning process is a key part of overall asset management in that it strongly influences how new assets are acquired. On an annual basis, all short to medium term expenditure on the network (capital, operating and maintenance) is evaluated and ranked on a consistent basis to ensure an optimum investment plan and budget allocation. The investment planning and risk management processes are integrated to ensure that investments provide the maximum benefits and efficiency to customers at the lowest lifecycle cost.

2.3.1.2 Network Augmentation Drivers

There are four key drivers for network augmentation addressed by the network planning process:-

- Load growth – The growing demand for electricity (typically over the summer period), whether through new customers connecting, or existing customers increasing their load that may overload our network;
- Safety – Overloaded electricity plant and equipment may pose a significant health and safety risk;
- Regulatory compliance – the required work to comply with all applicable regulatory obligations or requirements as defined in regulatory instruments including quality of supply;
- Supply reliability – the planning level to maintain supply reliability. As a last resort, overloaded plant can be managed by shedding supply to customers, thereby causing supply interruptions.

These drivers are consistent with the network augmentation obligations defined in the regulatory instruments.

2.3.2 PLANNING APPROACH

The general approach in developing this planning criteria, that JEN considers meeting the augmentation objectives and planning drivers outlined in Section 2.3.1, are:

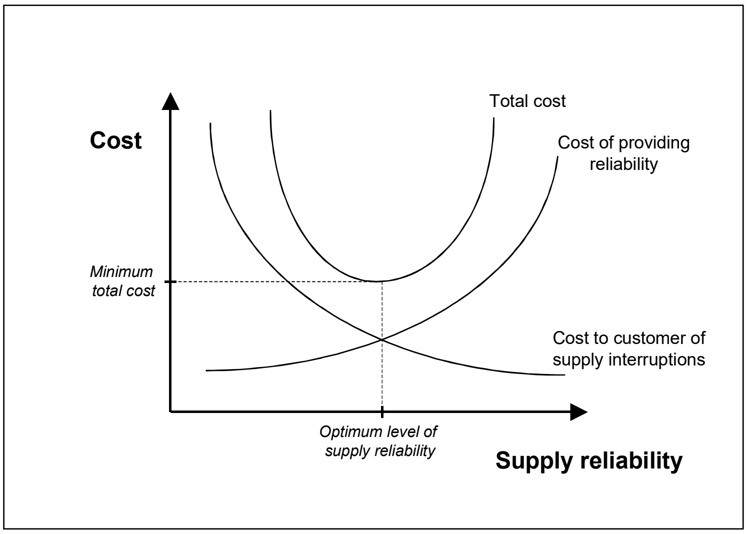
- For meshed network, as in the case of transmission connection points, sub-transmission lines and zone substations, a probabilistic method is adopted where the load is allowed to exceed the N-1 cyclic rating, and in some cases the system normal (N) rating, and the network is only augmented when it is economical. However, to maintain the safety of the distribution system, post-contingent and pre-contingent actions are defined based on the maximum short-term emergency rating. Refer to Schedule 1 for details.
- For high-voltage radial network, a probabilistic method is adopted for forecast load up to maximum safe loading limit. For forecast load above maximum safe loading limit, a deterministic method is adopted. This approach is to promote the efficient investment in additional network (or non-network) capacity while maintaining the safety of the distribution system. Effectively, maximising the utilisation of existing assets without infringing on the safety of the distribution system.
- For distribution substations and low-voltage network (which is considered a radial network), a deterministic method is adopted using the maximum permissible loading limit of the asset under system normal conditions. The criteria are set to approximate the prudent timing for when additional network (or non-network) capacity is required, such that it maximises the utilisation of existing assets without infringing on the safety of the distribution system.

The planning standards and criteria applied in network development are a significant determinant of network-related costs. Costs associated with distribution network facilities can be considered to be comprised of two parts:

- The direct cost of the service (as reflected in network use of system charges and the costs of losses); and
- Indirect costs borne as a consequence of supply interruptions caused by network faults, that is, network reliability.

In developing and applying this planning criteria, JEN aims to develop distribution network assets in an efficient manner that minimises the total (direct plus indirect) life cycle cost of network service borne by customers. This basic concept is illustrated in Figure 2-1.

Figure 2-1: Balancing the direct cost of service and the indirect cost of interruption



In addition, JEN's distribution network investment decisions aim to minimise the cost to customers, having regard for the costs and benefits of non-network alternatives to augmentation. Such alternatives include, but are not necessarily limited to, demand-side management and embedded generation.

3. PLANNING METHODOLOGIES

This section provides an overview of the analytical planning methodologies that must be applied and their associated inputs and assumptions (refer to Schedule 1).

There are two analytical planning methodologies:

- The probabilistic method is applied to network types with the most significant constraints and associated augmentation costs (refer to Section 3.1), and must be applied when assessing augmentations associated with:
  - transmission connection points;
  - sub-transmission lines;
  - zone substations; and
  - high-voltage (HV) feeders (for forecast load up to maximum safe loading limit).
- The deterministic method is a simplified approach that is only applied to:
  - high-voltage (HV) feeders (for forecast load above maximum safe loading limit); and

  individual distribution substations and associated low-voltage (LV) networks (refer to Section 3.2).

3.1 PROBABILISTIC METHOD

The probabilistic method:

- directly measures customer (economic) outcomes associated with future network limitations;
- provides a thorough cost-benefit analysis when evaluating network or non-network augmentation options; and
- estimates expected unserved energy (EUE), which is defined in terms of megawatt hours (MWh) per annum, and expresses this economically by applying a value of customer reliability ($/MWh).

Expected unserved energy (EUE)

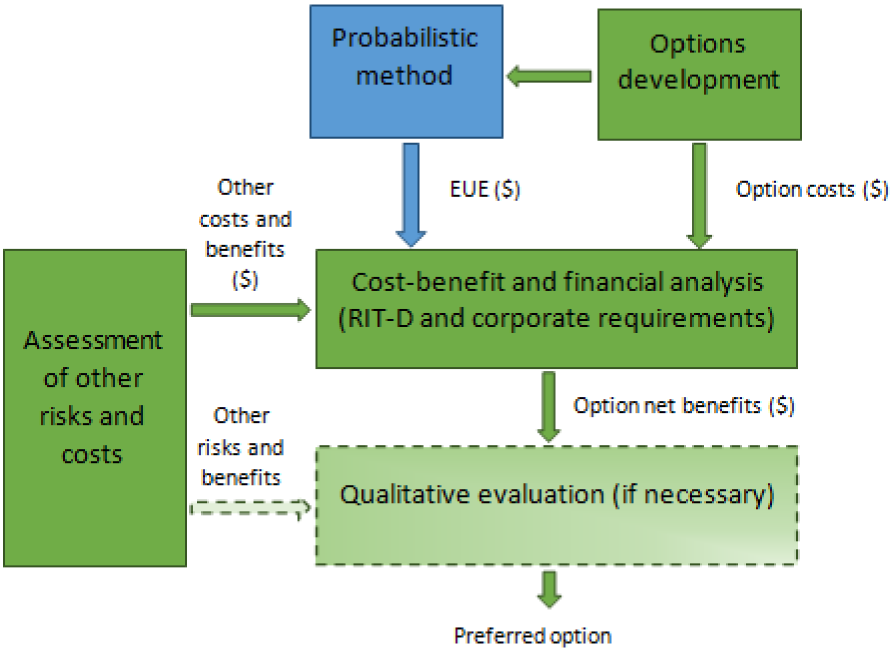
- EUE estimates the long-term probability weighted, average annual energy demanded (by customers) but not supplied representing the future degradation of electricity supply reliability as demand grows or changes.

The EUE measure is then transformed into an economic value, suitable for cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy (for more information, refer to Section 3.1.5).

Figure 3-1 shows how EUE is used within the broader context of network planning.

Public—31 January 2025 © Jemena Electricity Networks (Vic) Ltd

Figure 3-1: Overview of the probabilistic approach and the broader network-planning task



Using EUE to determine economic benefits

To determine an augmentation option's economic benefits:

1. The EUE estimate is applied to each credible augmentation option (network, non-network, and do-nothing) determined via the options development process. The change in each option's EUE, relative to doing nothing, establishes its economic benefit.
2. The economic benefit is then weighted against each option's costs (using discounted cash flow techniques) to determine the net benefit.

   Other quantifiable risks and costs that impact the National Electricity Market (NEM) can also be determined and evaluated through this cost-benefit analysis to establish:

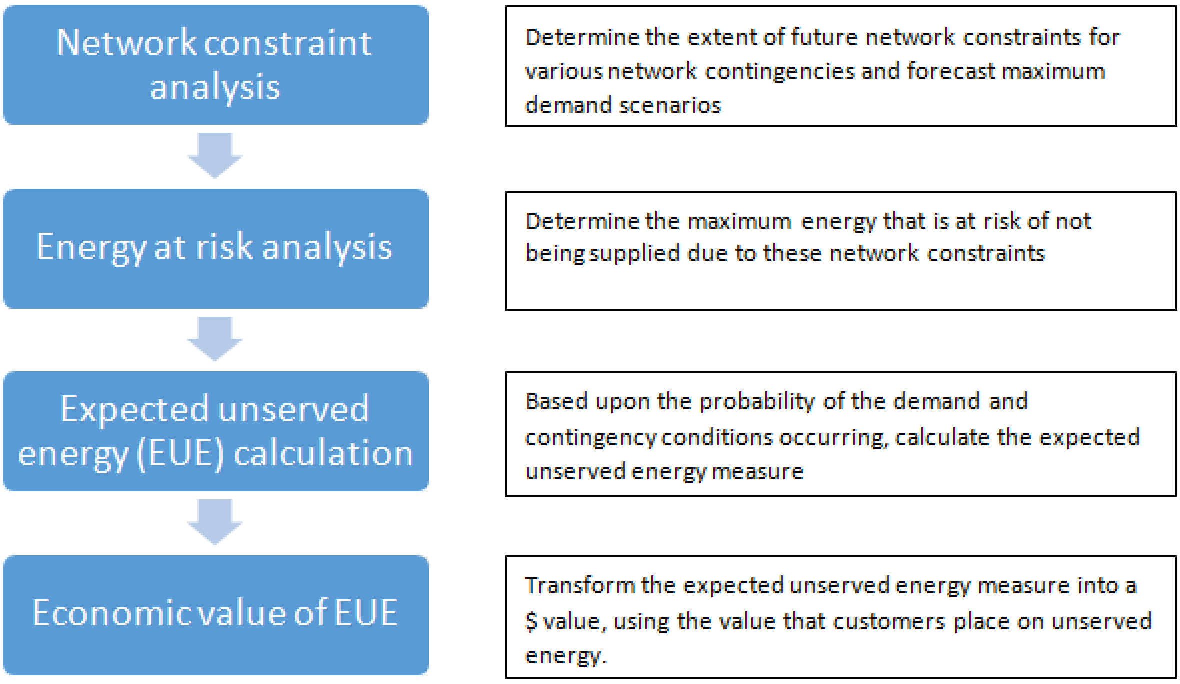
   - electricity losses;
   - changes in greenhouse gas emissions; and
   - asset renewal needs.
3. Where appropriate, unquantifiable risks and benefits are assessed (along with the results of the cost-benefit analysis) to inform on selecting the preferred option.

This procedure only focuses on the methodology, inputs and assumptions that must be used to apply the probabilistic method (calculating the EUE measure and its economic value).

3.1.1 PROBABILISTIC METHOD: INPUTS AND ASSUMPTIONS

Figure 3-2 shows the probabilistic method's four stages.

Figure 3-2: Overview of the probabilistic method's four stages



For information about the actual inputs and assumptions, refer to Schedule 1.

3.1.2 NETWORK CONSTRAINT ANALYSIS

The extent of a future network constraint is analysed by comparing an asset's forecast peak loading and its load limit for:

- each year of the planning outlook; and
- a range of contingencies (given loadings and load limits can depend on network conditions).

The inputs and assumptions associated with this stage include:

- **maximum demand scenarios**, which form a critical input for defining the maximum asset loading, and should incorporate the:
  - season (winter and/or summer), although the JEN network is typically summer peaking, there may be some circumstances when a winter peak will exceed the relevant winter rating;
  - probability of exceedence (POE), which defines the likelihood that the actual maximum demand (and resulting EUE) will differ from the projection due to more extreme or benign temperature conditions; and
  - economic growth assumptions, which define the likelihood that the actual maximum demand (and resulting EUE) will differ from the projection due to different economic growth outcomes.

 Public—31 January 2025 © Jemena Electricity Networks (Vic) Ltd

- **levels of embedded generation and demand-side support**, which can affect the asset loading (at the time of the maximum loading limit), and should incorporate:

  the forms of embedded generation or demand-side support that can assumed to be operating; and

  - their output relative to their capacity.

- **contingencies**, which can significantly affect both the asset loadings and their loading limits, and should incorporate the contingencies that will result in material levels of EUE, at the least covering system-normal conditions and the most credible single contingency

- **pre- and post-contingent operator actions**, which can affect either the asset loading or the maximum load limit and therefore the calculated level of EUE, and should incorporate:

  - reasonable expectations of what may actually occur at an operational level given the relevant contingent conditions
    - allowing for available reactive plant switching and control schemes operating appropriately, and
    - allowing for the use of available load transfers that are consistent with the asset thermal rating assumptions
  - **asset thermal ratings**, which typically define the loading limit and must be selected to reflect the assumed contingent conditions, and
  - **power quality obligations**, which under some circumstances can define the loading limit (for example, steady state voltage limits).

Depending on the circumstances, power flow and supply quality modelling may be necessary to determine the asset-loading relationships with the peak demand forecasts or the loading limit (particularly in circumstances where the loading limit is defined by a power quality obligation).

A power flow analysis is typically necessary to determine the loading and limits for interconnected lines, such as sub-transmission loop arrangements, and must apply the sources, inputs and assumptions defined in Schedule 1.

3.1.3 ENERGY AT RISK ANALYSIS

Energy-at-risk:

- represents the total energy at risk of not being supplied during system normal operation or if a contingency occurs, especially around the peak load period, and

- can be approximated by using a load duration curve that reflects the maximum demand scenario. The energy-at-risk is calculated from the amount of energy above the load limit line (N-1 rating) through the load duration curve.

Each maximum demand scenario and contingency will have its own energy-at-risk measure calculated for each year of the outlook period.

Figure 3-3 shows a load duration curve with a horizontal line representing a load limit (for a specific contingency). Figure 3-4 shows the same figure, magnified around the peak demand period, to illustrate the energy at risk calculation, which is represented by the area of the load duration curve above the load limit.

Figure 3-3: Load duration curve and load limit relationship

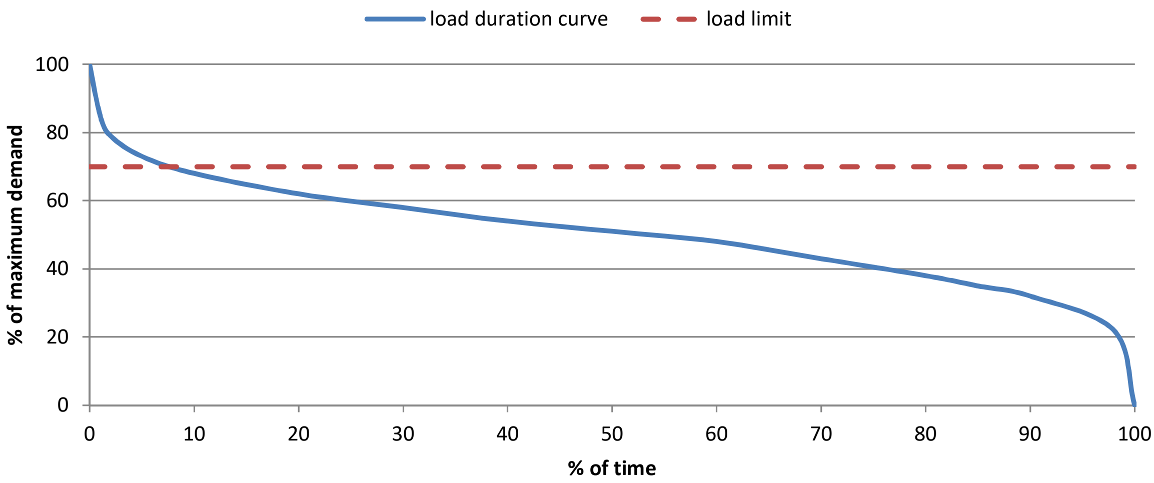
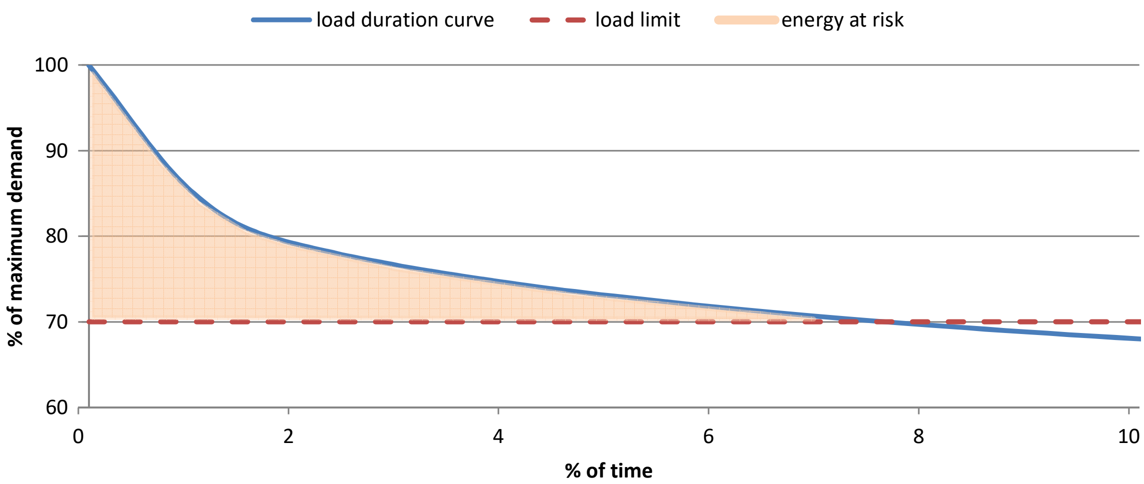


Figure 3-4: Energy-at-risk calculation for the area of the load duration curve above the load limit



The calculation's main assumption involves the projected load profile, which:

- must reflect the maximum demand projection scenario, and
- should be prepared from a recent historical load profile that best reflects the maximum demand projection's POE conditions.

3.1.4 EXPECTED UNSERVED ENERGY (EUE) CALCULATION

For a specific maximum demand scenario and contingency, the EUE measure (in units of energy) can be approximated by multiplying the:

- energy-at-risk measure calculated for a given network state, and
- probability of being in that network state.

In other words, this is the probability that the network will be in a particular contingency condition for a given maximum demand projection scenario.

The total EUE measure, in any year, is the sum of the various EUE measures, in that year, for each network state.

Calculating total EUE

In terms of calculation, assume $E@R_{c,d}$ represents the energy-at-risk measure for a state representing:

- the contingency condition, *c*, with the probability of being in that state, p_c, and
- a maximum demand scenario, *d*, with the probability of that scenario, p_d.
- the total $EUE = \sum(E@R_{c,d} \times p_c \times p_d)$, across all possible states of *c* and *d*.

The assumptions associated with calculating total EUE include the following:

- The maximum demand scenario weighting (probability):
  This is assumed to be 100% if only one scenario is used. Due to the non-linearity of the relationship of the maximum demand to the energy-at-risk, the probability may be adjusted to reflect the scenario's relative contribution to the total EUE measure. Refer to Schedule 1 for weightings applied by JEN.
- The contingency probability:
  This is typically approximated by the ratio of the contingency event rate (events per annum) multiplied by the typical duration of a contingency event to the number of hours per annum (8760).
  These parameters must be selected to represent the relevant contingency conditions assumed in the network constraint analysis stage.

3.1.5 ECONOMIC VALUE OF EUE

The economic value is established by multiplying the EUE measure by an appropriate value of customer reliability (VCR), where the VCR is:

- based on the estimated values and methodology derived and published by the AER under clause 8.12 of the NER, and
- the most appropriate for the assets being assessed and the customer base they supply.

In the case of generation at risk, EUE estimates the:

- Long-term probability-weighted, average annual energy generated by customers that is curtailed; and
- Future increase of electricity generation curtailment as demand declines or export increases.

The EUE measure is then translated into an economic value suitable for cost-benefit analysis using the AER's value of customer export curtailment (**CECV**) (in $/MWh), which reflects the economic cost per unit of generation curtailed.

To the extent that reduced network losses or reduced curtailment of embedded generation is able to displace fossil fuel generation, the AER's value of emissions reduction (VER) methodology can be applied.

3.2 DETERMINISTIC METHOD

The deterministic method:

- determines the need for augmentations using criteria that define the maximum permissible loading on assets, rather than by explicitly measuring customer outcomes, and

- is only used for high-voltage (HV) feeders (for forecast load above maximum safe loading limit), individual distribution substations and low-voltage network that are at risk of an unsafe failure, and makes no allowance for contingent conditions. These asset classes generally have a lower standard of load control and monitoring.

Deterministic method criteria

The criteria are set to approximate the prudent timing for when additional network (or non-network) capacity is required. The criteria developed within this method are predominantly based on the following two key drivers:

- maintain the safe operation of these assets; and
- maintain the supply reliability and quality provided by these assets under system-normal conditions (i.e. all network assets in-service).

The key assumptions and criteria associated with this method include the:

- maximum demand projection scenario (where only a single scenario is studied, as defined by the POE)
- contingencies considered (where only the system-normal state is assessed, given this method only applies to HV feeders and distribution substations), and
- loading limit (which represents the maximum permissible percentage loading, relative to a reference thermal rating, for the assumed maximum demand projection).

General points about the deterministic method

The deterministic method's risk/cost trade-off can be viewed in terms of the relationship between the maximum demand scenario's POE assumption, the percentage loading limit, and the assumed rating.

The loading and maximum demand on most distribution substations is not directly measured, so the maximum demand and forecast is estimated using the aggregated meter energy data (AMI and Non-AMI interval meters). The aggregating is done using enterprise analytics in conjunction with GIS data.

Additional actual load measurements (and risk assessments) on distribution substations are required to determine whether or not to augment the distribution substations identified via this methodology. This process is not covered by this procedure.

For HV feeders, deterministic method only applies for forecast load above maximum safe loading limit after accounting for load transfer to adjacent feeders. Maximum safe loading limit is determined based on the conductor and/or cable maximum operating temperature where these assets deteriorate rapidly to an unacceptable level or statutory clearance limit is likely to infringe when operating above this level.

Identifying network limitations for embedded generating units in aggregate method

When embedded generating units operate in aggregate, they may cause power to flow in the reverse direction through various points within the upstream high-voltage distribution network. The maximum reverse power export (i.e., the peak supply) is forecast at each transmission connection asset, sub-transmission line, zone substation and high-voltage distribution feeder.

The import ratings that are used for identifying network limitations under maximum demand conditions are generally not the same as the export ratings used for peak supply conditions. This is due to limitations in substation transformers' available buck-taps and On-Load Tap Changer (**OLTC**) mechanisms, which may not be able to curtail associated voltage rises within the network. Therefore, JEN calculates separate export ratings for each network asset under N (total capacity) and N-1 (firm delivery capacity) operating conditions.

Network limitations for embedded generating units in the aggregate are then identified by comparing the forecast peak supply (or forecast minimum demand) against the associated export rating for each network asset.

 Public—31 January 2025 © Jemena Electricity Networks (Vic) Ltd

The NER does not prescribe how export ratings should be calculated in terms of the regulatory reporting requirements for the DAPR. Therefore, the method adopted by JEN considers export ratings in the context of:

- **reverse power flow limitations** being the same as the forward power flow network rating (which may be determined by thermal capacity, protection or voltage drop considerations), except for some specific transformer OLTCs that can introduce up to a 70% reduction factor[3];
- **voltage rise limitations** being the maximum reverse power flow that
  - maintains voltage rises within acceptable limits while considering the voltage drops at maximum forward power flow to maintain regulatory compliance for the steady-state voltage limits at customers' points of supply to the network;
  - still maintains control of voltage with available zone substation transformer OLTC taps; and
- **downstream export ratings** that may limit the magnitude of the reverse power flowing back up into the upstream network.

The export rating for an asset is set to the lowest value of the above.

3 JEN zone substation transformer OLTCs fitted with single transition resistors e.g., Ferranti ES3, DS2 & DS5, Fuller 316. A 70% reduction factor is assumed by default for these types of OLTCs. Otherwise, 0% reduction factor is assumed.

4. SCHEDULE 1 – PLANNING CRITERIA

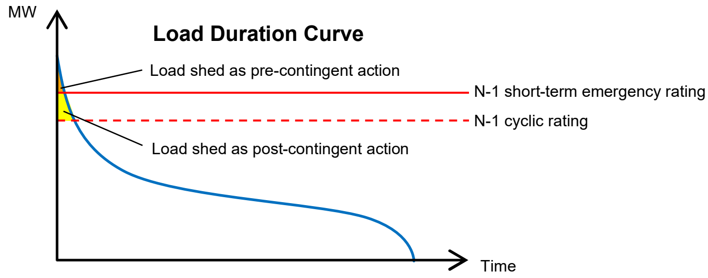
4.1 PROBABILISTIC METHOD CRITERIA

<table>
<tr><th>Criteria/assumptions</th><th>Transmission connection points</th><th>Sub-transmission lines</th><th>Zone substations</th><th>HV feeder</th></tr>
<tr><td>Planning horizon (minimum)</td><td>10 years</td><td>5 years</td><td>5 years</td><td>5 years</td></tr>
<tr><td>Planning method</td><td>Probabilistic method</td><td>Probabilistic method</td><td>Probabilistic method</td><td>Probabilistic method for forecast load up to maximum safe loading limit.
Deterministic method for forecast load above maximum safe loading limit.</td></tr>
<tr><td colspan="5">Customer/maximum demand (MD) and weather assumptions</td></tr>
<tr><td>MD and weather POE (and scenario weighting)</td><td colspan="4">• 10% POE MD (30% weighting).
• 50% POE MD (70% weighting).
(Summer and winter, where appropriate).
• 10POE condition (summer) refers to an average daily ambient temperature of 32.9ºC, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
• 50POE condition (summer) refers to an average daily ambient temperature of 29.4ºC, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC. For overhead conductors and underground cables ratings calculations at 50POE summer condition, JEN is currently adopting the maximum ambient temperature of 35ºC, however this input assumption is currently under review.
• 50POE and 10POE condition (winter) are treated the same, referring to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC. It should be noted that winter load are not critical, as JEN's network is summer peaking and winter rating is higher than summer rating.</td></tr>
<tr><td>Economic growth (and scenario weighting)</td><td colspan="4">Expected forecast demand growth (central scenario), noting that RIT-D requires a weighting to be applied to a range of credible scenarios.</td></tr>
<tr><td>Load profile relevant to peak demand assumption</td><td colspan="4">• Historical average load profile (typically previous 5-10 years), scaled to 10% POE MD forecast.
• Historical average load profile (typically previous 5-10 years), scaled to 50% POE MD forecast.</td></tr>
<tr><td>Approved source of MD forecast data</td><td>AEMO's publication of DNSP – Victorian terminal station demand forecast.</td><td>Derived from load flow (modelling) analysis using the zone substation MD forecasts (defined under the zone substation criteria) and diversity factors.</td><td>Internally derived and approved zone substation forecast.</td><td>Internally derived and approved high-voltage (HV) feeder forecast.</td></tr>
<tr><td colspan="5">Embedded generation and demand-side support assumptions</td></tr>
</table>

Criteria/assumptions	Transmission connection points	Sub-transmission lines	Zone substations	HV feeder
	• The assumed contribution from embedded generation (below 1 megawatt (MW)) is inherently allowed for through the maximum demand forecast which has regard to historical observed demand and generator output at the time of peak demand. • The maximum demand forecast assumes that registered solar panel installations or Inverter Energy Systems are assumed to be running during times of peak demand, albeit at reduced output due to temporal differences. • Other generators (above 1 MW) are generally assumed not to be supplying because there are no current JEN network support contracts. • The list of embedded generators above 1MW (including capacity, year of installation, and zone substation connection) is recorded in the Jemena Electricity Networks Load Demand Forecast Model, which is updated annually. • There are no current JEN network support contracts with demand side providers or embedded generators.			
Network analysis				
Network modelling form	• Spreadsheet analysis to determine energy at risk and expected unserved energy. • Power flow modelling to assess loadings on individual transformers.	Spreadsheet analysis to determine energy at risk and expected unserved energy, supported by load flow analysis to determine loop flows for contingent conditions.	Spreadsheet analysis to determine energy at risk and expected unserved energy.	
Network model parameters				
Impedance sources	AEMO power flow model and AusNet Transmission Group transformer data sheet.	Circuit Data Sheet, stored in JEN's Drawbridge data system.	Transformer Data Sheet	Conductors and cables data sheet in Excel spreadsheet and stored in CYMDIST load flow software
Load model	100% constant power; 0% constant current; and 0% constant impedance, except where the limitation being assessed is a voltage stability constraint.			
Contingencies considered	• System-normal • Major outage of a single transformer.	• System-normal • Outage of a single line.	• System-normal • Major outage of a single transformer.	• System-normal • Outage of a single feeder.
Technical envelope				

Criteria/assumptions	Transmission connection points	Sub-transmission lines	Zone substations	HV feeder
Asset rating parameters	• Normal: Normal cyclic rating for 10POE and 50POE conditions. • N-1: Cyclic rating (N-1) for 10POE and 50POE conditions where 90-day rating has been used	• Overhead lines: nominal ratings for 10POE and 50POE conditions, as per line design, construction type and standard environmental conditions. • Underground cables: cyclic ratings for 10POE and 50POE conditions, based upon actual design, construction parameters and environmental conditions (approximately 90-day cyclic rating, covering the relevant summer or winter period). • N-1 overhead lines maximum safe loading limit (summer) is determined under various environmental conditions where the conductor operating temperature is likely to exceed 150ºC where the conductor annealing effect is accelerated to an unacceptable level or statutory clearance limit is likely to infringe.	• Normal: nameplate ratings for 10POE and 50POE conditions, covering the maximum continuous rating with all available cooling operating. • N-1 cyclic rating : 90-day cyclic ratings for 10POE and 50POE conditions, assuming 0.03% loss of life per day • N-1 limited cyclic rating: One daily cyclic ratings for 10POE and 50POE conditions, assuming 0.03% loss of life per day. Other plant limit that restricts the output capability may apply. • N-1 2-hour emergency rating: Two-hour cyclic ratings for 10POE and 50POE conditions. Other plant limit that restricts the output capability may apply.	• Overhead lines: nominal rating for 10POE and 50POE conditions, as per line design, construction type and standard environmental conditions. • Overhead lines maximum safe loading limit (summer) is determined under various environmental conditions where the conductor operating temperature is likely to exceed 100ºC where the conductor annealing effect is accelerated to an unacceptable level or statutory clearance limit is likely to be infringed. • Underground cables: cyclic ratings for 10POE and 50POE conditions, based upon actual construction parameters and environmental conditions (approximately 90-day cyclic rating, covering the relevant summer or winter period). • Underground cable maximum safe loading limit is the cyclic rating.

Criteria/assumptions	Transmission connection points	Sub-transmission lines	Zone substations	HV feeder
System normal (N) and single credible contingency (N-1) criteria	**System Normal** Normal cyclic rating as provided by AusNet Transmission Group for 10POE and 50POE conditions. **N-1 Condition** Cyclic rating (N-1) as provided by AusNet Transmission Group for 10POE and 50POE conditions.	**System Normal** Overhead lines nominal ratings for 10POE and 50POE conditions. Underground cables cyclic ratings for 10POE and 50POE conditions. **N-1 Condition** *Post contingent action:* Overhead lines nominal ratings and underground cables cyclic ratings for 10POE and 50POE conditions, for load up to 120% of relevant POE ratings (without auto load shedding scheme) and 130% of relevant POE ratings (with auto load shedding scheme). *Pre-contingent action:* For load beyond 120% of relevant POE ratings (without auto load shedding scheme), and load beyond 130% of relevant POE ratings (with auto load shedding scheme)	**System Normal** Nameplate rating for both 10POE and 50POE conditions, covering the highest continuous rating allowing for available cooling methods (typically OFAF rating). **N-1 Condition** *Post contingent action:* Cyclic rating (N-1) for load up to limited cyclic rating (N-1) (without auto load shedding scheme) and two-hour emergency rating (with auto load shedding scheme), for 10POE and 50POE conditions. *Pre-contingent action:* For load beyond limited cyclic rating (N-1) (without auto load shedding scheme), and two-hour emergency rating (with auto load shedding scheme), for 10POE and 50POE conditions	**System Normal** Overhead lines nominal ratings for 10POE and 50POE conditions. Overhead lines maximum safe loading limit (summer) is approximately the same as 50POE rating. Underground cables cyclic ratings for 10POE and 50POE conditions. Underground cables maximum safe loading limit is the cyclic rating. **N-1 Condition** Overhead lines nominal ratings for 10POE and 50POE conditions. Underground cables cyclic ratings for 10POE and 50POE conditions.
Source of ratings data	Provided by asset owner, AusNet Transmission Group.	Circuit Data Sheet, stored in the Drawbridge data system.	Zone Substation Data Sheet (hard copy only).	Collated for use in the Jemena Electricity Networks Load Demand Forecast Model
Power quality obligations (e.g. steady state voltage levels)	Defined by VEDCoP and NER.			

Criteria/assumptions	Transmission connection points	Sub-transmission lines	Zone substations	HV feeder
Assumed pre- and post-contingent actions	The diagram below illustrates the pre- and post- contingent actions.  • Pre-contingent action: In the event of a critical plant outage, any load above the N-1 short-term emergency rating will not be able to be shed in time to avoid plant damage, such as conductor annealing, and associated risk to public safety. Therefore, this proportion of load (shaded orange above) is assumed to be shed as a pre-contingent action prior to any contingency event on any days where the load is forecast to exceed the short-term emergency rating. Due to the certainty that this load will be shed, a probability of 1 is applied to this portion of the energy at risk for the purpose of the unserved energy calculation. • Post-contingent action: Following a contingency event, the remaining load above the N-1 cyclic rating (shaded yellow above) will be manually shed as a post-contingent action, typically within 24 hours for transformer and 30 minutes for sub-transmission line. For the purposes of the expected unserved energy calculation, a probability representing the likelihood of a contingency event is applied to this portion of the energy at risk. • Short-term emergency ratings for transformers are determined based on guideline defined in the Australian Standard (AS2374.7-1997). For sub-transmission overhead line, short-term rating is ~130% of conductor nominal rating where the maximum conductor operating temperature is expected to reach ~150ºC. As recommended in the Australian Standard (AS/NZS 7000:2010), if the conductor is operated beyond this level, the loss of tensile strength becomes unacceptable even for a short operating time (~30 minutes). The above load shedding actions assume that there is no remaining transfer capacity available.			
Treatment of load transfer capability	Allowance for the use of available load transfers that are consistent with the asset thermal rating assumptions			
Outage probability				
Outage rate	1/100 year - major failure.	0.1 per kilometres per annum.	1/100 year - major failure.	Based on average of historical data where available, otherwise assumed to be 1 outage per year
Outage duration	2.6 months (unplanned replace duration).	4 to 8 hours (depending on location)	2.6 months (unplanned replace duration).	4 to 8 hours (depending on location)
Basis of outage data	CIGRE data (outage rate), typical unplanned replacement durations (assuming spares are unavailable).	Typical data, based on operational planning.	CIGRE data (outage rate), typical unplanned replacement durations (assuming spares are unavailable).	Typical data, based on operational planning.

 Public—31 January 2025 © Jemena Electricity Networks (Vic) Ltd

Criteria/assumptions	Transmission connection points	Sub-transmission lines	Zone substations	HV feeder
Assumed restoration/repair actions	No spares are available.	Typical restoration process.	No spares are available.	Typical restoration process.
Economic				
VCR	Using AER VCR figures, weighted by customer-type proportions.	Using AER VCR figures, weighted by customer-type proportions supplied by sub-transmission loop.	Using AER VCR figures, weighted by customer-type proportions supplied by zone substation.	Using AER VCR figures, weighted by customer-type proportions supplied by HV feeder.
Losses	Weighted average wholesale market price (if applicable) applied to the reduction in network losses.			
VER	Using AER VER figures (if applicable) for the reduction in greenhouse gas emissions.			
CECV			Using AER CECV figures for the aggregated generation energy curtailed at customer sites supplied by zone substation.	Using AER CECV figures for the aggregated generation energy curtailed at customer sites supplied by HV feeder.
Source of VCR data	In accordance with the AER value of customer reliability review[4] and JEN customer energy consumption composition between residential, commercial and industrial.			

4.2 DETERMINISTIC METHOD CRITERIA

Criteria/assumptions	Distribution substations
Planning horizon (minimum)	Five (5) years.
Maximum demand forecast assumptions	10% POE (summer and winter, where appropriate).
Source of MD forecast data	Business Objects report which uses aggregated meter energy data to calculate the MD.
Contingency considered	System normal (N) only.
Maximum loading limit	100% of cyclic rating at 10POE condition
Source of rating	Jemena Distribution Construction Manual, Circuit Data Sheets and Plant Data Sheets.

[4] In July 2018, a final Rule determination on the VCR came into effect, giving the AER responsibility for developing and publishing a VCR methodology and VCR estimates. In December 2019, the AER published its VCR methodology and VCR estimates in the “AER, Final Report on VCR values, December 2019”, available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/final-decision