Jemena Electricity Networks (Vic) Ltd

2023 Distribution Annual Planning Report

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2023 Distribution Annual Planning Report

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Executive Summary

Jemena Electricity Networks (**JEN**) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. JEN's service area covers 950 square kilometres of northwest greater Melbourne and includes the Melbourne International Airport, which is located at the approximate physical centre of the network, and some major transport routes.

The network comprises over 6,800[1] kilometres of electricity distribution lines and cables, delivering approximately 4,374 GWh of energy to over 375,000 homes and businesses for several energy retailers. The network service area ranges from Couangalt, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

The 2023 Distribution Annual Planning Report (**DAPR**) details the past performance of Jemena's electricity network, summarises the asset management, demand forecasting and network development methodologies adopted by JEN, and presents forecast maximum and minimum electricity demand for the forward planning period (five-year planning period from 2024 to 2028). The report also identifies existing and emerging network limitations and identifies and proposes credible options to alleviate or manage the identified electricity network limitations.

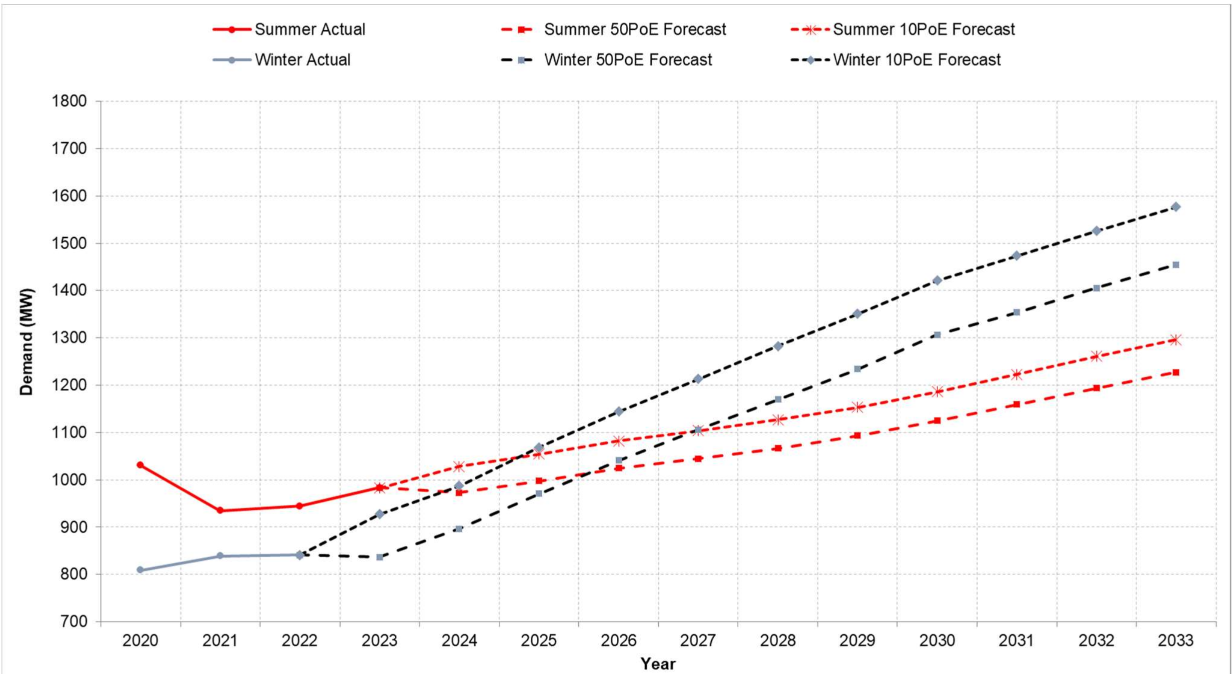
Maximum demand growth

As a whole, the growth in maximum demand across JEN's network is progressively increasing, with the total underlying (excluding large customer load forecast) network 50% POE maximum demand forecast to grow at an average rate of 3.54% per annum over the next five years (2023-24 to 2027-28). The network maximum demand is forecast to occur in the winter from 2026 onwards as a result of gas electrification as per Victoria's Gas Substitution Roadmap. The overall of gradual electrification of gas on the network is assessed and forecasted according to the availability of consumer gas data. The short term forecast predicts the yearly space heating and hot water profiles for residential and commercial customers, and the longer term forecast comprises of electrification to new greenfield customers and gradual electrification to existing brownfield customers.

Figure 1 shows the historical observed maximum demand and ten-year forecasts for summer and winter, 10% POE and 50% POE conditions.

[1] Does not include low voltage services.

Figure 1: JEN historical and total maximum demand forecast



Despite the general growth in demand at the network level, there are areas within the network where maximum demand is forecast to grow well beyond the network average level, while other parts of the network are forecast to experience a decline in maximum demand as a result of manufacturing closures.

In general, JEN expects strong growth in the northern half of the network. This is largely due to new developments associated with urban sprawl towards the edge of the urban growth boundary. As a result of this urban sprawl and the extension of the urban growth boundary, JEN expects to see continued strong growth in the areas currently supplied by the Kalkallo (maximum demand forecast to grow at 12.2% per annum over the next five years), Sydenham (3.99% p.a.), Somerton (4.80% p.a.) and Coolaroo (4.37% p.a.) zone substations.

Some pockets within established inner suburbs are also experiencing strong growth as a result of amendments to the planning schemes for high-density living. The high growth is predominately driven by the development of high-rise residential and office buildings, and the expansion of community facilities and services, such as around Footscray Central Activities Area, Fairfield and Essendon Airport. As a result, JEN is forecasting relatively high growth in maximum demand for areas currently supplied by Flemington (8.79% p.a.), Yarraville (3.46% p.a.), Fairfield (8.00% p.a.), Footscray East (3.77% p.a.), Footscray West (6.49% p.a.), Coburg North (4.34% p.a.), Coburg South (1.79% p.a.), North Essendon (2.88% p.a.), and Newport (1.80% p.a.) zone substations.

In other parts of the network, generally to the south, JEN is expecting low growth or a decline in maximum demand over the forward planning period. Table 1 presents a summary of the expected growth/decline in maximum demand across JEN over the next five years.

Table 1: Supply area average annual maximum demand growth rate (2023-24 to 2027-28)

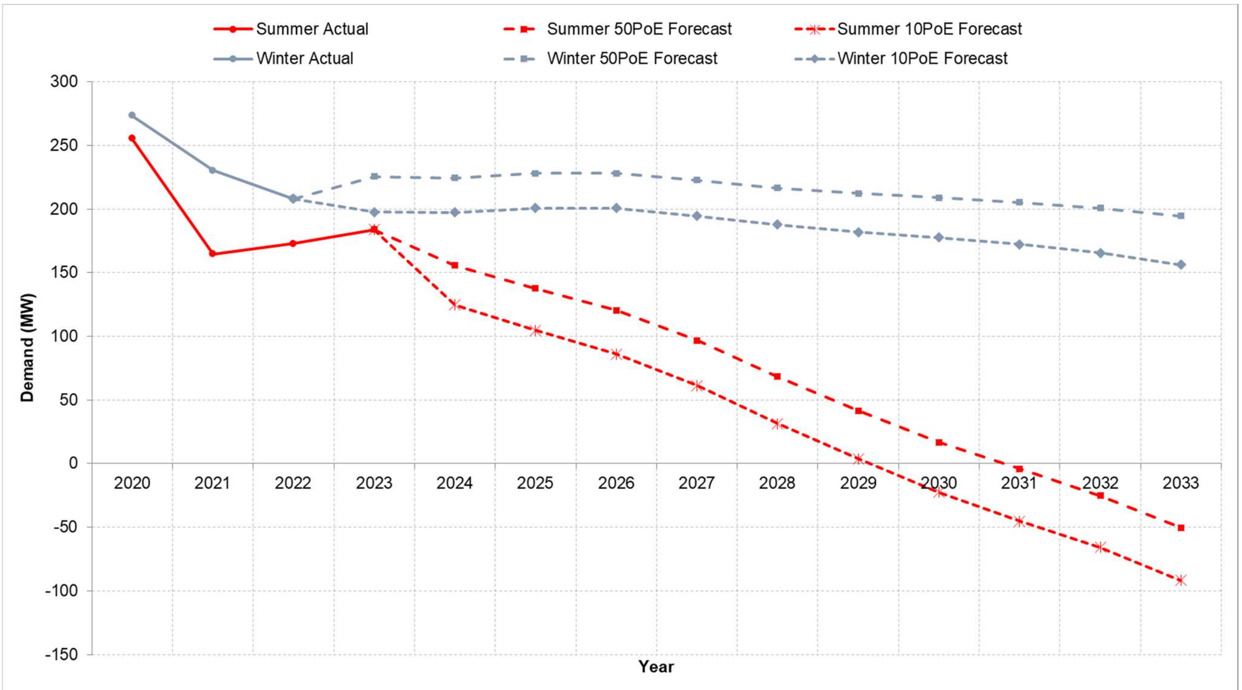
Season	Supply area average annual growth (2022-23 to 2027-28)			
	Strong growth (>5% p.a.)	High growth (3-5% p.a.)	Medium growth (1-3% p.a.)	Low growth and possible decline (<1% p.a.)
Summer	Fairfield, Footscray West, Kalkallo	Coburg North, Flemington, Sunbury, Sydenham, and Somerton	Broadmeadows, Braybrook, Coburg South, Coolaroo, East Preston (EP), Footscray East, North Heidelberg North Essendon, Newport, Tullamarine, Tottenham, and Yarraville	Airport West, Preston, Broadmeadows South, Essendon, Heidelberg, Pascoe Vale
Winter	Fairfield, Flemington, Kalkallo, Sunbury, and Sydenham	Braybrook, Coburg North, Coburg South, Coolaroo, East Preston (EPN), Footscray East, Footscray West, Heidelberg, North Heidelberg, North Essendon, Pascoe Vale, Somerton, Tottenham, and Yarraville	Airport West, Broadmeadows, Broadmeadows South, Essendon, Newport, Preston, St. Albans, Tullamarine, and Watsonia	Thomastown

Minimum demand decline

At the same time, the minimum demand across JEN's network is expected to continue to decline rapidly from the continued uptake of embedded generation (in particular, solar PV systems) at an average rate of -22 MW per annum under 50% POE over the next five years (2023-24 to 2027-28).

Figure 2 shows the historical annual observed minimum demand and ten-year forecasts for 10% POE and 50% POE conditions.

Figure 2: JEN historical and total minimum demand forecast



Despite the strong decline in minimum demand at the network level, there are areas within the network where minimum demand is forecast to decline well beyond the network average level, to the point where minimum demand may go negative, while other parts of the network are forecast to experience a slower decline.

In general, JEN expects a strong decline in minimum demand (or strong growth in embedded generation) in the northern half of the network. This is largely driven by 7-star building code new developments associated with urban sprawl towards the edge of the Urban Growth Boundary where solar PV installations are expected to be demanded as part of the new development. As a result of this urban sprawl and the extension of the Urban Growth Boundary, JEN expects to see a continued strong decline in minimum demand in the areas currently supplied by the Coolaroo and Kalkallo zone substations. Table 2 presents a summary of the expected decline in minimum demand across JEN's network over the next five years.

Table 2: Supply area average annual minimum demand decline rate (2023-24 to 2027-28)

Season	Supply area average annual decline rate (2023-24 to 2027-28)			
	Strong decline (less than minus 3 MVA pa)	High decline (minus 2-3 MVA pa)	Medium decline (minus 1-2 MVA pa)	Low decline and possible growth (greater than minus 1 MVA pa)
Annual under 50% POE	Coolaroo, Kalkallo	Airport West, Broadmeadows, North Heidelberg, Sunbury, Sydenham, Somerton	Coburg South, Heidelberg, Preston, Pascoe Vale	Braybrook, Broadmeadows South, Coburg North, Essendon, Fairfield, Flemington, Footscray East, Footscray West, North Essendon, Newport, East Preston, Tullamarine, St. Albans, Thomastown, Tottenham, Watsonia and Yarraville
Annual under 10% POE	Coolaroo	Airport West, Kalkallo, North Heidelberg, Sunbury, Sydenham, Somerton	Coburg South, Broadmeadows, Essendon, Footscray West, Heidelberg, Preston, Pascoe Value	Braybrook, Broadmeadows South, Coburg North, Fairfield, Flemington, Footscray East, North Essendon, Newport, East Preston, Tullamarine, St. Albans, Thomastown, Tottenham, Watsonia and Yarraville

Network augmentation

Due to varying (and non-coincidental) maximum demand growth across JEN's network, the utilisation forecasts for several assets justify network augmentation. As a result, and to maintain asset utilisation at levels that support the safe, efficient and reliable delivery of electricity to our customers, JEN is proposing to undertake the following key (i.e. with a cost of over $6 million) network developments within the next five years:

- Augment Brunswick-Fairfield (BTS-FF) 22 kV loop by November 2025;
- New 22 kV feeder SHM-013 by November 2026;
- Upgrade two transformers at Sunbury (SBY) zone substation by November 2027;
- Augment Brunswick-North Essendon (BTS-NS) 22 kV loop by November 2027;
- Establish a new zone substation at Craigieburn (CBN) by November 2027;
- Augment Thomastown-NEI-North Heidelberg-NEL-Watsonia 66 kV loop by November 2027; and
- Continue converting the East Preston supply areas from 6.6 kV to 22 kV and the retirement of the East Preston Zone Substation by 2028.

Asset replacement

JEN is responsible for managing its existing assets to ensure ongoing safety and reliability of supply. Utilising asset condition monitoring techniques, JEN has identified the following major projects on assets that are near the end of their useful life and pose increased public safety and reliability risks, justifying their replacement of over $6 million within the next five years:

- Replacement of Footscray West Zone Substation 22 kV switchgear and associated protection relays by June 2025;
- Replacement of the Fairfield Zone Substation transformer and installation of a fourth bus by November 2025;
- Replacement of the two Heidelberg Zone Substation transformers by November 2024;
- Replacement of Coburg North Zone Substation 22 kV switchgear and associated protection relays by November 2027;
- Replacement of Coburg South Zone Substation 22 kV switchgear and associated protection relays by November 2028.

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Glossary

Advanced Metering Infrastructure (AMI) meter	Also referred to as a smart meter, an AMI meter is an electronic device that, among other functions, records electricity consumption at hourly (or less) intervals and communicates that information to a utility for monitoring and billing.
capital expenditure (CAPEX)	Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits.
condition-based risk management (CBRM)	Refers to a management process that utilises current network asset condition information, engineering knowledge and practical experience to predict future asset conditions and to calculate the risks of asset failures to guide investment decisions.
constraint	Refers to a constraint on network power transfers that affects customer supplies or the ability for embedded generators to supply into the network.
contingency condition (or event)	Refers to the loss or failure of part of the network. For example, a single contingency condition is the loss of a single plant item - referred to as an ‘N-1’ condition or 'N-1' operating state. An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements.
contingency probability	The probability that a contingency condition (or event) will occur, and typically approximated by multiplying the number of times a contingency condition occurs (usually in a year) by its duration, normalised by the total available time (in this case, a year).
Customer Export Curtailment Value (CECV)	Represents the dollar value of the market benefits of avoided generation (export) curtailment as a result of network investment.
degree of polymerisation (DP) value	Refers to the value established from diagnostic testing and historical data that indicates the condition of paper insulation within the transformer, and is an important parameter in its end-of-life assessment.
deterministic method	A simplified planning methodology that does not explicitly take into account outage or environment condition probability to guide investment.
Import energy-at-risk	The total energy at risk of not being able to supply load.
export energy-at-risk	The total energy at risk of needing to curtail generation.
expected unserved energy (EUSE)	In the case of load at risk, EUSE refers to an estimate of the long-term probability-weighted, average annual energy demanded (by customers) but not supplied, and future degradation of electricity supply reliability as demand grows or changes. The EUSE measure is then translated 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. In the case of generation at risk, EUSE refers to an estimate of 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 EUSE measure is then translated into an economic value, suitable for cost-benefit analysis, using the value of DER (CECV) (in $/MWh), which reflects the economic cost per unit of generation (export) curtailed.

export rating	Export ratings define the network's capability to transfer reverse power flows (flows from that location upstream towards the transmission point of connection). An export 'N' rating applies as the technical limit for reverse power flow at that location when the network is in a system-normal state. It is the total capacity to accept supply from embedded generating units. An export 'N-1' rating applies as the technical limit for reverse power flow at that location when the network is in a single contingency state. It is the firm delivery capacity to accept supply from embedded generating units.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, JEN is 100% owned by Jemena and services over 369,000 customers within a 950 square kilometre distribution system covering the north-west area of greater Melbourne.
import rating	Import ratings define the network capability to transfer forward power flows (i.e., flows downstream towards customer loads) at that location. An import 'N' rating applies as the technical limit for forward power flow at that location when the network is in a system normal state. An import 'N-1' rating applies as the technical limit for forward power flow at that location when the network is in a single contingency state.
limitation	Refers to a limitation on a network asset's capability to transfer power.
load duration curve	Shows the amount of time (usually over a year) that demand was within a given percentage of the maximum demand (MD).
maximum demand	The highest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for a particular season (summer and/or winter) or the year. This is also referred to as the peak load, as seen by the network.
Maximum demand scenario	Refers to the possible (projected) maximum demand resulting from a given 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.
Medium-voltage (MV)	Refers to voltage levels that are greater than 1kV and up to 35kV, as defined in AS/NZS 61000.3.6:2012
Megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.
minimum demand	The lowest amount of net electrical power imported (or forecast to be imported), from the grid to supply customers (in aggregate) for a particular season (summer and/or winter) or the year. If this is not greater than zero, then it is the highest amount of net electrical power exported (or forecast to be exported), into the grid from embedded generating units (as seen by the network, in aggregate) for a particular season (summer and/or winter) or the year. This is also referred to as the peak supply, as seen by the network.
Momentary Average Interruption Frequency Index (MAIFI)	A reliability index commonly used by electricity utilities, MAIFI is the average number of momentary interruptions that a customer will experience during a given period (typically a year). A momentary interruption is defined as an outage of less than one minute in duration.
national meter identifier (NMI)	A unique number used to identify a meter (the electricity connection point) measuring electricity consumption.
network	Refers to the physical assets required to transfer electricity to customers.
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 (or rating)	Refers to the network's capability to transfer electricity.
non-network	Refers to anything potentially affecting the transfer of electricity to customers that does not involve the network.

non-network alternative	A response to growing customer demand that does not involve network augmentation.
on-load tap-changer (OLTC)	A mechanism in transformers that allows for variable turn ratios to be selected in discrete steps whilst the transformer is on load, which enables stepped voltage regulation without supply interruption.
operating expenditure (OPEX)	Expenditure (ongoing) for running a product, business or system.
peak demand	The highest amount of electrical power delivered (or forecast to be delivered) for a particular period.
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	Refers to the fitness of electrical power for the consumer devices it is required to supply. The Victorian Electricity Distribution Code of Practice (EDCoP) and National Electricity Rules (NER) set the power quality obligations for Jemena Electricity Network's (JEN) network operations.
power transformer	Refers to a power transformer installed in a zone substation and includes any associated ancillary equipment. Power transformers in the JEN system transform a subtransmission voltage into a distribution voltage.
probabilistic method	A planning methodology applied to network types with the most significant constraints and associated augmentation costs. It involves estimating the cost of a network limitation with consideration of the likelihood and severity of network outages and operating conditions.
probability of exceedance (POE)	Refers to the probability, as a percentage, that a forecast will be exceeded (for example, due to weather conditions) for a particular period.
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 distribution network investments in the National Electricity Market (NEM).
Rapid Earth Fault Current Limiter (REFCL)	Rapid Earth Fault Current Limiter or REFCL means any plant, equipment or technology (excluding neutral earthing resistor) that is: (a) designed to reduce the effect of distribution system faults and when operating as intended may lead to a REFCL condition; and (b) approved by Energy Safe Victoria in an electricity safety management scheme or bushfire mitigation plan pursuant to the Electricity Safety Act 1998 (Vic).
REFCL condition	REFCL condition means an operating condition on the 22 kV distribution system arising from the proper operation of a REFCL which results in the neutral reference of the distribution system moving to allow the un-faulted Phase to Earth voltage magnitude to approach a value close to the Phase to Phase voltage magnitude. The term 'operating condition on the 22 kV distribution system' in this term extends up to, but not beyond any device or plant which is functionally equivalent to an isolating transformer.
reserve feeder (service)	A service ensuring continuity of supply if the normal feeder supply to a customer's connection is interrupted. Reserve feeder capacity comes from an alternative feeder with the capacity to meet the customer's requirements.
SAP	SAP is a software application used within Jemena to support several functions including procurement and logistics, works and asset management, customer management, resource management and operation analytics.
service target performance incentive scheme (STPIS)	A scheme administered by the Australian Energy Regulator (AER) that is designed to provide incentives for each distribution network service provider (DNSP) to maintain or improve service reliability.

substation service isolating transformer	Refers to a substation service transformer that is supplied from the low-voltage (LV) network. See also substation service transformer.
substation service transformer	Refers to a transformer that provides auxiliary power supplies for battery chargers, OLTC controls, general light, and power inside an electricity zone substation. Substation service transformers can be supplied from the high voltage (HV) or low voltage (LV) network (where they are referred to as substation service isolating transformers).
System Average Interruption Duration Index (SAIDI)	A reliability index commonly used by electricity utilities, SAIDI is the average outage duration experienced by customers served and is measured in units of time (often minutes or hours).
System Average Interruption Frequency Index (SAIFI)	A reliability index commonly used by electricity utilities, SAIFI is the average number of interruptions experienced by a customer, measured in units of interruptions per customer.
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. Referred to as an ‘N’ condition or ‘N’ operating state.
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).
zone substation	Refers to the location of transformers, ancillary equipment and other supporting infrastructure that facilitate the electrical supply to a particular zone in the Jemena Electricity Network (JEN).

Station Names

ACI	Australian Glass Manufacturers Zone Substation
APF	Australian Paper Fairfield Zone Substation (decommissioned)
AW	Airport West Zone Substation
BD	Broadmeadows Zone Substation
BMS	Broadmeadows South Zone Substation
BK	Brunswick Zone Substation
BLTS	Brooklyn Terminal Station
BTS	Brunswick Terminal Station
BY	Braybrook Zone Substation
CBN	Craigieburn Zone Substation (proposed)
CN	Coburg North Zone Substation
COO	Coolaroo Zone Substation
CS	Coburg South Zone Substation
EP-A	East Preston Zone Substation Switch House A
EP-B	East Preston Zone Substation Switch House B
EPN	East Preston Zone Substation
ES	Essendon Zone Substation
FE	Footscray East Zone Substation
FF	Fairfield Zone Substation
FT	Flemington Zone Substation
FW	Footscray West Zone Substation
GSB	Gisborne Zone Substation
HB	Heidelberg Zone Substation
KLO	Kalkallo Zone Substation
KTS	Keilor Terminal Station
L	Deepdene Zone Substation
MAT	Melbourne Airport Zone Substation
MB	Melbourne Water Zone Substation
MLN	Melton Zone Substation
NEI	Nilsen Electrical Industries Zone Substation
NH	North Heidelberg Zone Substation
NS	North Essendon Zone Substation
NT	Newport Zone Substation
P	Preston Zone Substation (66 kV / 6.6 kV decommissioned in 2017)

PLN	Plumpton Zone Substation (proposed)
PTN	Preston Zone Substation (proposed 66 kV /22 kV)
PV	Pascoe Vale Zone Substation
Q	Kew Zone Substation
SBY	Sunbury Zone Substation
SHM	Sydenham Zone Substation
SMTS	South Morang Terminal Station
SPS	Somerton Power Station
SSS	Somerton Switching Station
ST	Somerton Zone Substation
TH	Tottenham Zone Substation
TMA	Tullamarine Zone Substation
TT	Thomastown Zone Substation
TSTS	Templestowe Terminal Station
TTS	Thomastown Terminal Station
VCO	Visy Coolaroo Zone Substation
WGT	West Gate Tunnel Zone Substation
WMTS	West Melbourne Terminal Station
WND	Woodend Zone Substation
WT	Watsonia Zone Substation
YVE	Yarraville Zone Substation

Abbreviations

AAC	All Aluminium Conductor
ABC	Aerial Bundled Conductor
ABS	Asset Business Strategy
ACR	Automatic Circuit Recloser
ACS	Asset Class Strategy
ACSR	Aluminium Conductor Steel Reinforced
ADMS	Advanced Distribution Management System
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIP	Asset Investment Plan
AMI	Advanced Metering Infrastructure
AS/NZS	Australian Standard/New Zealand Standard
CAPEX	Capital expenditure
CB	Circuit Breaker
CBRM	Condition-Based Risk Management
CC	Covered Conductors
CCT	Circuit
CECV	Customer Export Curtailment Value
CMEN	Common Multiple Earth Neutral
COWP	Capital and Operational Work Plan
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAPR	Distribution Annual Planning Report
DB	Distribution Business
DC	Direct Current
DEECA	Department of Energy, Environment and Climate Action, Victoria
DER	Distributed Energy Resources
DM	Demand Management
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
DPAR	Draft Project Assessment Report
DPV	Distributed Solar PV
DR	Demand Response

DSO	Distribution System Operator
DUoS	Distribution Use of System (charges)
EDCoP	Victorian Electricity Distribution Code of Practice
EDPR	Electricity Distribution Price Review
E@R	Energy at Risk
EG	Embedded Generation
ENEA	Enea Consulting
ENA	Energy Networks Association
EPA	Environment Protection Authority
ERP	Enterprise Resource Planning (system)
ESC	Essential Services Commission
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
EUSE	Expected Unserved Energy (also EUE)
FLISR	Fault Location, Isolation and Supply Restoration
FPAR	Final Project Assessment Report
GIS	Geospatial Information System
GSL	Guaranteed Service Level
GSP	Gross State Product
HBRA	Hazardous Bushfire Risk Area
HV	High Voltage
IS	Information Services
ISP	Integrated System Plan
IT	Information Technology
JEN	Jemena Electricity Networks (Vic) Ltd
kA	Kilo Amps
kV	Kilo Volts
LBRA	Low Bushfire Risk Area
LGA	Local Government Area
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MD	Maximum Demand
MED	Major Event Day
MEN	Multiple Earth Neutral
MV	Medium Voltage
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt

MWh	Megawatt hour
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NST	Neutral Supply Test
NUoS	Network Use of System
OLTC	On Load Tap Changer
OMS	Outage Management System
OOS	Out of Service
OPEX	Operating expenditure
PCB	Polychlorinated Biphenyl
POE	Probability of Exceedance
PQ	Power Quality
PQCA	Power Quality Compliance Audit
PV	Photo-voltaic
RIN	Regulatory Information Notice
REFCL	Rapid Earth Fault Current Limiter
RIT-D	Regulatory Investment Test – Distribution
RMU	Ring Main Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	Jemena's ERP system
SAPS	Stand-alone Power Supply
SCADA	Supervisory Control And Data Acquisition
STPIS	Service Target Performance Incentive Scheme
TCPR	Transmission Connection Planning Report
THD	Total Harmonic Distortion
TNSP	Transmission Network Service Provider
URD	Underground Residential Development
USE	Unserved Energy
VCR	Value of Customer Reliability
VVC	Volt VAr Control
ZS	Zone Substation

1. Introduction and Network Overview

1.1 Purpose of the DAPR

This 2023 Distribution Annual Planning Report (**DAPR**) has been prepared by JEN as the Distribution Network Service Provider (**DNSP**) for the north-west area of greater metropolitan Melbourne and in accordance with the requirements set out in clause 5.13 of the National Electricity Rules (**NER**).

The DAPR, which includes an overview of our network and operating environment, presents a proposed network development plan to economically manage the network and network limitations identified within the forward planning period (the five-year planning period from 2024 to 2028).

The DAPR also summarises:

- The annual planning review of our electricity distribution network;
- Past performance and information about existing and forecast distribution network limitations; and
- Our asset management system, and forecasting and network planning methodologies used to identify network limitations and assess credible options to manage or alleviate those limitations.

The DAPR is the key mechanism for communicating identified network limitations to industry and interested parties and forms an essential part of the network development consultation process. Assessments are conducted at a high level to identify and indicate the relative magnitude of network limitations, without conducting a detailed network development strategy level of assessment. Interested parties, particularly potential non-network and stand-alone power supply (**SAPS**) providers who are potentially able to provide network support services are encouraged to use the DAPR as a platform for discussing alternative options that may help manage network loading and ensure ongoing reliable and cost-efficient electricity supply to JEN's customers.

1.2 Jemena Electricity Network

JEN is the licensed electricity distributor for the north-west area of greater metropolitan Melbourne. JEN's network supplies electricity to approximately 375,000 customers across a 950 square kilometre area. It supplies a mix of major industrial areas, residential growth areas, established inner suburbs, some major transport routes, and the Melbourne International Airport, which is located at the approximate geographical centre of the network.

Figure 1-1 shows the JEN supply area, which ranges from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south, and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

Figure 1-1: Jemena electricity network supply area

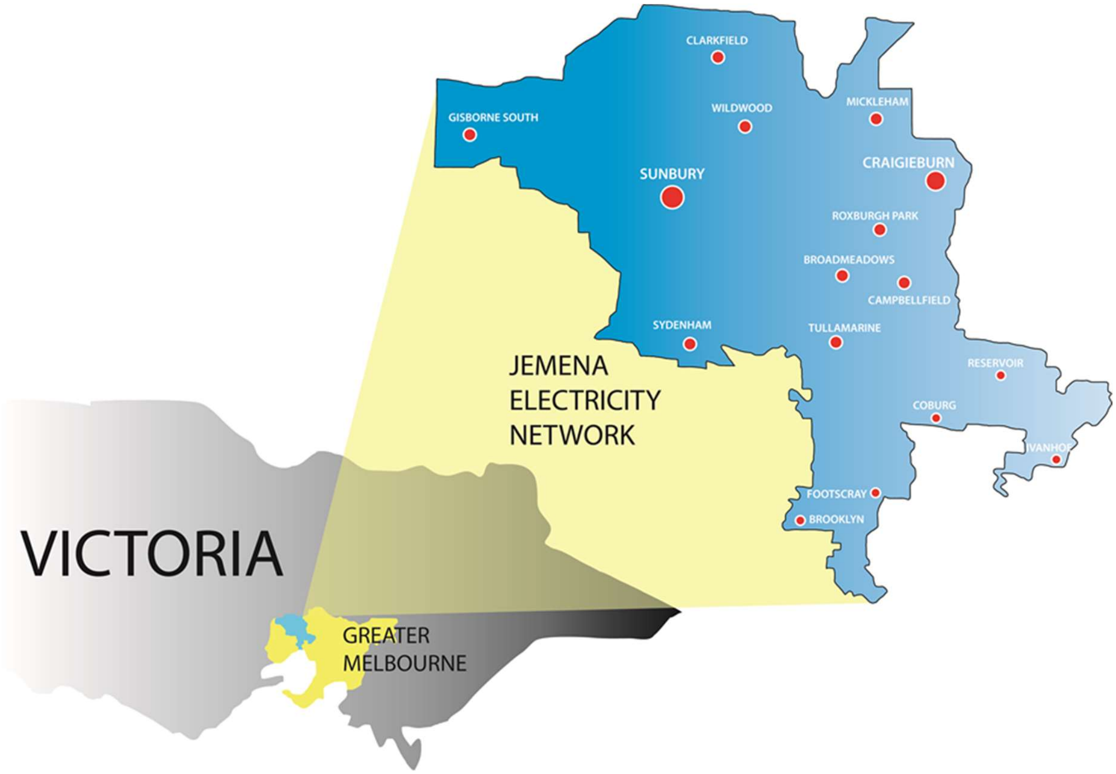


Table 1-1 presents a summary of the network's key characteristics.

Table 1-1: Network summary as at June 2023

Network characteristic	Characteristic detail
Supply area (location)	North-west metropolitan Melbourne
Supply area (square kilometre)	950
Line length (km)	6,899 (4,490 overhead and 2,409 underground)
Subtransmission lines (number and voltage)	46 (66 kV and 22 kV)
Feeder lines (number)	232 (22 kV, 11 kV and 6.6 kV)
Electricity poles (number)	106,877
Transmission connection points (location)	Brunswick, Brooklyn, Keilor, South Morang, Templestowe, Thomastown, West Melbourne
JEN-owned zone substations (number)	27
Zone substations combined capacity (MVA)	1,980
Distribution transformers (number)	7,000

1.3 Operating Environment

JEN operates in an environment that is impacted by its network characteristics, ownership and control, stakeholders, regulatory objectives and expenditure drivers. The key factors impacting asset management include:

- Customer preferences associated with the supply of electricity;
- Conditions associated with managing ageing assets present technical risks for safety, reliability and the environment;
- Significant regulatory compliance obligations;
- The physical environment (e.g. weather patterns, urbanisation etc.) in which the assets are located;
- The bushfire risk profile of where the assets are located; and
- The changing nature of the key services provided by network assets with increasing embedded generation and storage connections, and the availability of smart metering devices.

JEN's operating environment is changing. Increasing penetration of customer solar photovoltaic (**PV**) systems and the emergence of small-scale energy storage technologies are creating operational and power quality challenges, particularly regarding steady-state voltage management. Changing regulatory obligations are impacting safety and compliance work plans, and growing customer expectations and awareness are creating new challenges for providing reliable, cost-efficient and environmentally responsible energy delivery.

JEN recognises that its network is ageing and that, because of the associated condition deterioration, some assets that were operating satisfactorily in the past may no longer meet safety, compliance or service performance requirements in the future. In response, JEN continues to review its asset management strategies to ensure that assets continue to perform and are efficiently renewed to a level that meets stakeholder and technical requirements.

JEN also continues to focus on maintaining its service performance, while evaluating initiatives to adapt to a changing environment, including:

- Implementing changes to bushfire management;
- Improving network resilience and management of extreme weather events;
- Responding to government energy policy initiatives;
- Developing and applying smart network technologies;
- Integrating distributed energy resources (**DER**);
- Developing options and flexibility for our network and customers by applying demand management solutions; and
- Leveraging the advanced metering infrastructure as a catalyst for improvement.

2. Network Development Process and Drivers

This section provides an overview of JEN's network development process, including a summary of the annual planning review process and asset management system. It also provides a summary of the maximum and minimum demand forecasting methodology and network planning methodologies used to identify, assess and address network limitations.

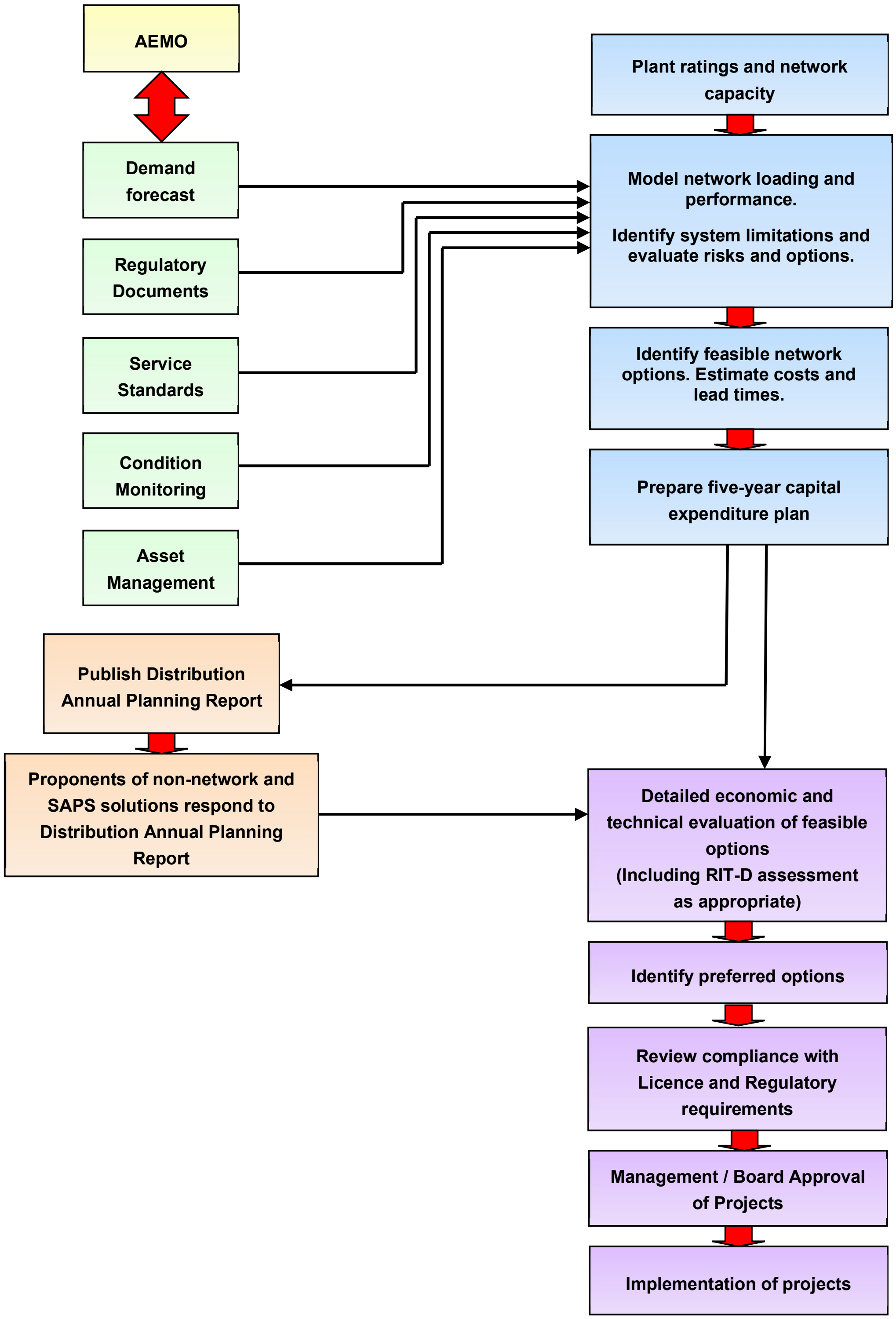
2.1 Annual Planning Review Process

The Distribution Annual Planning Report (**DAPR**) forms part of the annual planning process undertaken by JEN and is a summary of the annual electricity distribution network planning review. The review process includes an assessment of supply limitations and risks on the subtransmission lines, zone substations and high-voltage feeders. It also identifies and proposes feasible options for managing or mitigating identified network limitations. Network planning is a continuous process with key activities including:

- Monitoring and reviewing asset and network performance;
- Preparing demand forecasts;
- Identifying network limitations;
- Identifying feasible options to manage or mitigate network limitations; and
- Identifying and proposing the most feasible option to maximise the net economic (i.e. customer) benefits.

Figure 2-1 provides a high-level flow chart of the annual planning review process.

Figure 2-1: Annual planning review process flow chart



2.1.1 Transmission network joint planning

Joint planning with Victoria's Transmission Network Service Provider (**TNSP**) and jurisdictional planning authority, the Australian Energy Market Operator (**AEMO**), is conducted in accordance with clause 5.14.1 of the NER.

A key outcome of this joint planning is the preparation of the Transmission Connection Planning Report (**TCPR**), which is prepared in collaboration with the four other distribution network service providers (**DNSPs**) in Victoria[2] in accordance with clause 19.3 of the Victorian Electricity Distribution Code of Practice (**EDCoP**).

The TCPR assesses supply limitations and identifies proposed augmentation for assets that connect the Victorian transmission network to distribution networks, such as the 220/66 kV and 220/22 kV transformers. Although the DNSPs undertake connection asset capacity planning, the assets are generally owned and managed by Victoria's TNSP, AusNet (Transmission).

Demand and energy forecasts for JEN's connection points can be found in the 2023 TCPR[3].

A Memorandum of Understanding, agreed between AEMO and the five Victorian electricity DNSPs, sets out a framework for cooperation and liaison between AEMO and the DNSPs regarding the joint planning of the shared network and connection assets in Victoria.

It also sets out the approach to be applied by AEMO and the DNSPs in assessing options to address limitations in a distribution network where one of the options consists of investment in dual function assets or transmission investment, including connection assets and shared transmission network assets.

Where connection asset capacity planning requires significant development of existing, or establishment of new, terminal station assets, AEMO will be involved in the joint planning process. Where connection assets are shared between DNSPs, the DNSP with the majority of its demand supplied by the affected asset will typically lead the planning assessment.

2.1.2 Distribution network joint planning

Joint planning with surrounding DNSPs is conducted in accordance with clause 5.14.2 of the NER. Table 2-1 below summarises shared subtransmission assets for which Jemena conducts joint planning with other DNSPs.

Table 2-1: Shared DNSP asset planning

66 kV subtransmission loop	Shared asset owner	2021 Digital DAPR map reference
KTS-SBY (WND-GSB)-SHM	Powercor	KTS-SBY-SHM-KTS 66 kV loop
TSTS-HB-L-Q	CitiPower	TSTS-HB-L-Q-TSTS 66 kV loop
TTS-NEI-NH-WT	AusNet (Distribution)	TTS-NEI-NH-WT-TTS 66 kV loop

Jemena and the neighbouring DNSP will share demand forecasts, and the relevant DNSP who owns the asset will conduct the assessment in accordance with the planning obligations (see section 2.4.1).

For example, planning for the TTS-HB-L-Q subtransmission loop requires both Jemena and CitiPower to share demand forecasts for their respective substations because the TSTS-HB 66 kV line is owned by JEN, whereas the TSTS-L 66 kV line is owned by CitiPower.

2 The five Victorian DNSPs are: Jemena, CitiPower, Powercor Australia, United Energy, and AusNet (Distribution).

3 http://jemena.com.au/industry/electricity/network-planning.

2.2 Asset Management Approach

JEN is committed to employing good industry asset management practices to prudently manage our assets over their total life cycle. JEN recognises the importance of sound asset management in ensuring the efficient delivery of services that meet customer and stakeholder requirements.

Network design, construction, maintenance, operations, asset investment and innovation are vital components of asset management, with effective asset management having a direct impact on customer service, electricity pricing, safety and shareholder value.

JEN undertakes these activities in accordance with its asset management framework.

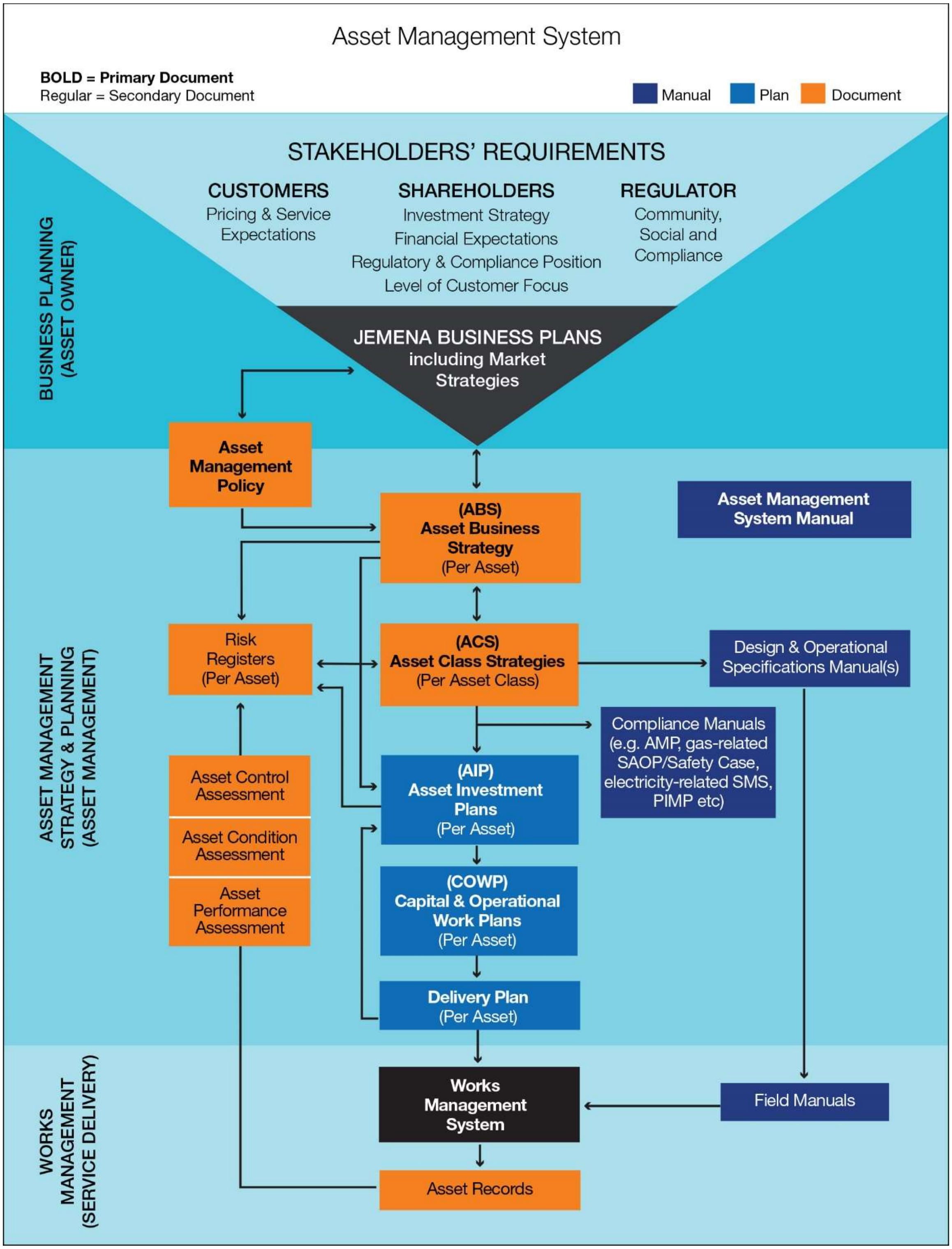
2.2.1 Asset management framework

JEN's asset management framework governs the process of establishing work programs focused on safety, people, performance, our customers and growth, and includes a series of documented policies and objectives comprised of:

- Asset Management Policy – This policy statement describes JEN's intentions and the principles for asset management as they are applied throughout the business; and
- Asset Management documents including:
    - The 20-Year Asset Business Strategy (**ABS**), which informs the long-term operation and asset management trends, long-term customer preferences, and the influence of new technology and policy changes on the business operations;
    - The 7-Year Asset Investment Plan (**AIP**), which provides a medium-term outlook of asset investment plans; and
    - The Capital and Operational Work Plan (**COWP**), which provides a two-year plan of activities to be performed in designing, constructing, operating, maintaining and supporting JEN's electricity distribution network.

Figure 2-2 shows the document hierarchy for JEN's asset management system. The asset management framework incorporates the asset management system's scope and boundaries in terms of JEN's policies, strategies, objectives and plans, all of which ensure the appropriateness of our asset management activities.

Figure 2-2: Jemena asset management framework



2.2.2 Asset management drivers

Jemena has identified a series of strategic asset management drivers. Along with specific asset class drivers, these drivers are used as the basis for developing asset management strategies and include:

- Customer and community expectations;
- Stakeholder expectations;
- Climate change;
- Growth, demand and customer connections;
- Supply reliability and quality;
- Compliance, safety and the environment; and
- Technological developments.

2.2.3 Asset management strategies and objectives

Jemena's asset management strategies and objectives are developed to:

- Maintain the existing service levels, including customer service, quality, and reliability of supply;
- Ensure alignment with Jemena's business plan and asset management policy;
- Ensure existing asset utilisation and the capacity to meet load growth are achieved;
- Ensure obligations for the connection of new customers are met; and
- Manage asset performance, condition and risks (network, asset and public safety).

This section lists:

- Key measures of success used by Jemena to support the Jemena Business Plan;
- Electricity asset management objectives that align with these measures; and
- Strategies applied to address these asset management objectives.

Section 2.2.4 describes the individual asset class strategies for each of Jemena's asset classes, applied to achieve the above asset management policy directives.

Safety

Jemena's safety-related asset management policy directives include:

- Manage our assets without compromising the safety of our employees, contractors and the public and in an environmentally sustainable manner as per the Jemena Health, Safety, Environment and Quality Policy,
- Apply the Jemena risk management and assurance approach to asset management activities; and
- Facilitate innovation and continual improvement in the safety and performance of the assets, through the establishment, maintenance and governance of effective asset and safety management systems.

Strategies to address these include:

- Provide a safe environment for employees, contractors, and the public that meets or exceeds our corporate standards and the requirements of relevant state and federal legislation, making safety our number one priority;
- Provide a safe and environmentally sound network and workplace, and manage health and safety to eliminate workplace accidents, injuries and illnesses;
- Take a proactive approach to identify risks that may affect the network, and manage both the prevention and response to risk events;

- Maintain effective disaster recovery business continuity processes supported by approved plans that meet or exceed good industry practice;
- Complete regular safety audits and manage network risks through the successful application of risk management controls and frameworks in conjunction with risk management systems to maintain the current risk profile; and
- Maintain registers, records and documentation to ensure that risk management activities are traceable and provide the foundation for improvement in methods and tools, as well as in the overall risk management process.

People

JEN's asset management policy directives include developing staff skills and knowledge to sustain, reinforce and extend our asset management capabilities.

Strategies to address this directive include:

- Develop the skills and knowledge of our people to sustain, reinforce and extend our asset management capabilities and competencies.

Customer

JEN's asset management policy directives include actively engaging with customers and key stakeholders to understand and respond to their requirements to ensure outcomes are achieved that are in their long-term interests.

Strategies to address the above include:

- Establish an annual process to communicate asset performance (reliability, safety, functionality) to customers and key stakeholders;
- Incorporate customer expectations and outcomes into our Asset Management plans and documents;
- Review equipment and design specifications to improve procurement options and reduce asset lifecycle costs;
- Ensure customer service levels and customer obligations are met;
- Embed customer engagement in the processes for developing all capital programs and projects;
- Determine the most cost-effective means of developing the network to meet future loading requirements and customer needs; and
- Demonstrate initiatives to drive reductions in cost per customer without deterioration in service levels in Asset Management Plans.

Performance

The asset management policy directives include:

- Comply with all relevant regulatory and legislative requirements;
- Develop a suite of asset management documents whose deliverables complement the Jemena Business Plan in achieving relevant corporate and asset management objectives;
- Adhere to effective project management and contract management frameworks that support effective delivery decisions and activities throughout the asset lifecycle by adopting a standardised approach that considers time, cost and quality parameters;
- Make best practice asset management an aspirational goal to incorporate within our 'business as usual' approach, and measure it against an internationally recognised asset management framework;
- Develop and maintain asset information systems that support asset management decisions and activities throughout the asset lifecycle and
- Ensure our asset management decision-making is balanced by incorporating criteria that consider performance, cost, risk and our net-zero emissions target by 2050.

2.2.4 Asset class strategies

JEN produces asset class strategies for each of its asset classes. Each asset class strategy covers several asset sub-classes. These strategies summarise the optimal lifecycle management plan for each asset class and consider:

- Managing existing asset performance, risk and condition; and
- Strategies for asset acquisition and creation, utilisation, maintenance and renewal/disposal.

The documents are developed by considering:

- Asset class profile, which includes information about the type, specifications, life expectancy and age profile of each of the asset class in service;
- Asset strategies, which include key strategies and plans that support Jemena's business plan, asset management policy, and asset management strategies and objectives, as well as informing expenditure plans and programs of work;
- Asset risk, which includes information about asset criticality, failure risks, types and consequences;
- Asset performance, which provides information about performance objectives, drivers and service levels, and the technical and commercial risks associated with the management of the asset; and
- Asset expenditure assessment, which provides information about the expenditure decision-making processes, how expenditure options are analysed, and historical and forecast operating expenditure (**OPEX**) and capital expenditure (**CAPEX**). This also includes decisions about whether to renew or dispose of assets that have reached the end of their economic life based on their performance, risks and supply security or service level requirements.

Table 2-2 lists Jemena's asset sub-classes, along with the number of assets in each sub-class.

Table 2-2: JEN assets by asset class as at June 2023

Asset Class	Population	Asset Class	Population
Automatic Circuit Reclosers	141	Public lighting luminaires	78,573
Communications Cable (Metallic and Fibre)	533 km	Surge Arresters	7,326
LV Overhead and Underground Services	282,405	Underground Cable (excluding services)	2,409 km
Pole Type Substations	4,267	Zone Substation Capacitor Banks	45
Non-Pole Type Distribution Substations	2,697	Zone Substation Circuit Breakers	618
Overhead Conductor (excluding services)	4,490 km	Zone Substation Current Transformers	347
Distribution Switchgear	16,903	Zone Substation DC Systems	104
Poles	106,877	Zone Substation Protection Relays	2,136
Pole Top Structures	138,776	Zone Substation Transformers	73
Power Quality Systems	57	Zone Substation Voltage Transformers	239

2.2.5 Asset criticality, performance and risks

JEN assesses the consequence of failure for each asset sub-class and selects an appropriate lifecycle management strategy for that asset sub-class. The asset criticality determines the level of analysis required to formulate each asset sub-class strategy, based on a balance of the risk, performance, and costs associated with the asset. Table 2-3 shows that, for most of our asset classes, condition assessment is our primary asset replacement strategy.

In some circumstances, JEN will allow assets to fail. This is typically the case for non-critical or consumable devices such as LV fuses or assets where condition monitoring is difficult or disproportionally expensive to implement relative to the risks of failure, such as for underground cables.

Some assets may exhibit premature failure due to the onset of common defects (such as technology or a design-related issue). In this case, JEN typically implements accelerated programs to replace these assets.

Run to failure-based replacement

In this strategy, assets are deliberately allowed to operate until they break down, at which point reactive maintenance or replacement is performed. This is generally used as the base case for investment decisions.

Age-based replacement

While actual asset replacement decisions may include a condition assessment, forecast volumes for planning and regulatory approval purposes may be based on an age or failure rate assessment only.

In practice, age-based replacement is only utilised for non-major road lamps, which are replaced every four years to ensure sufficient lumens are emitted according to Public Lighting Code clause 2.3.1(c).

Condition-Based Risk Management

Condition Based Risk Management (**CBRM**) is a structured process that combines asset information, engineering knowledge and practical experience to define the future condition, performance and risk for network assets. JEN uses its CBRM model to support the condition, age, and failure rate assessment methodologies.

Condition monitoring can be invasive, non-invasive or a combination of both. Non-invasive assessment includes activities such as inspections, infra-red surveys and limited testing procedures. Invasive assessment includes activities such as oil sampling and equipment overhauls. Invasive assessment is usually associated with a greater range of inspections and testing procedures.

Currently, the CBRM model is being applied to ten asset sub-classes:

1. Zone substation transformers
2. Zone substation circuit breakers
3. Zone Substation disconnectors and isolators
4. Poles
5. Pole tops (cross-arms and insulators)
6. Pole type transformers
7. Ground-type/indoor transformers
8. HV overhead switches
9. Ring Main Units (**RMU**s)
10. Automatic Circuit Reclosers (**ACR**s)

JEN uses the CBRM to identify poor-performing assets that will affect the service delivered to our customers.

Critical CBRM inputs include:

- the asset owner's engineering knowledge and practical experience of the assets;

- asset specification, history (faults, failures, generic experience, maintenance records), duty, environment, test and inspection results;
- an understanding of degradation and failure modes; and
- experience of building CBRM models.

CBRM outputs include:

- condition, which provides health indices, health index profiles, probability of failure and failure rates, and estimates of future failure rates with different interventions; and
- risk, which provides quantification of the current and future risk for asset groups with different interventions (expressed as a monetary value), criticality involving changed priorities within an asset group, and comparison/optimisation across asset groups.

Condition evaluation is applied within the CBRM models to identify the optimum replacement strategy and estimate any future movement in risk for a given replacement strategy. These models are also used to verify that our plans are maintaining reliability, security and safety, rather than improving or degrading them.

Table 2-3 summarises the asset lifecycle strategy adopted for each asset sub-class.

Table 2-3: Asset lifecycle strategy for each asset sub-class

Asset	Condition Assessment	Run To Failure	Age-Based
Poles	✓ (1)		
Pole Tops	✓ (1)		
Conductors and Connectors	✓ (1)		
Overhead Line Switchgear	✓	✓ (2)	
Automatic Circuit Reclosers (ACR)	✓ (1)		
Public Lighting		✓ (3)	✓ (4)
HV Outdoor Fuses	✓		
Surge Arrestors	✓		
Pole Type Transformers	✓ (1)		
Non-Pole Type Distribution Substations	✓ (1)		
Earthing Systems	✓		
Underground Distribution Systems		✓	
LV Services	✓		
Communications Network Devices	✓		
Metallic Supervisory Cables and Fibre Optic Cables	✓		
iNet Radio and 3G Communications Systems	✓		

Asset	Condition Assessment	Run To Failure	Age-Based
Multiplexers and Voice Frequency Equipment	✓		
Remote Terminal Units	✓		
Substation Grounds	✓		
Zone Substation Capacitors	✓		
Zone Substation Circuit Breakers	✓ (1)		
Zone Substation Instrument Transformers	✓		
Zone Substation DC Supply Systems	✓		
Zone Substation Disconnectors and Buses	✓ (1)		
Zone Substation Protection Systems	✓		
Zone Substation Transformers	✓ (1)		
Power Quality Monitoring Systems	✓		
Metering	✓		
GPS Clocks	✓		
Tools and Equipment	✓		
Vehicles and Fleet	✓		

(1) Condition-based risk management models have been applied to these asset classes

(2) LV fuse is a consumable device and is typically run to failure. For all other classes of overhead switchgear, condition assessment is conducted as part of routine use via the network operators, during which time notifications are raised for the rectification of defects or replacement of assets as identified. In addition, overhead switchgear is visually inspected every three to four years, and all switches and disconnectors are included in the thermal survey of overhead lines. It is expected that some hot connections and contacts will be detected, and thereby programmed for repair.

(3) Major roads public lighting is patrolled three times a year to ensure the lamps are in working order according to Clause 2.3.1(f) of the Public Lighting Code. The patrols are intended to identify defective lamps or sections of lights, lanterns, poles, brackets and access cover plates, which may otherwise remain defective for prolonged periods.

(4) Alongside non-major roads, lamps are replaced every four years to ensure sufficient lumens are emitted according to Clause 2.3.1(c) of the Public Lighting Code

Technical compliance

The services we provide and the operations we carry out are heavily regulated regarding safety and environmental obligations, as are the service standards we must meet and the prices we can charge.

Our principal regulatory bodies are:

- The Essential Services Commission (**ESC**);
- Energy Safe Victoria (**ESV**);
- The Environment Protection Agency (**EPA**); and
- The Australian Energy Regulator (**AER**).

We invest in the network to ensure we meet safety and environmental regulations. We adhere to safety and security standards when we design and undertake work on our assets. We ensure that vegetation growing near our assets does not pose a safety hazard, and in recent years we have been required to implement several additional bushfire mitigation measures. We must also comply with various environmental obligations related to vegetation, contaminants, noise, and greenhouse gas emissions.

Asset replacement programs have also been developed to ensure that safety and reliability are maintained and that we meet our safety, environmental and guaranteed service level regulatory and legislative requirements, while we also focus on adhering to our company policies concerning employee and public safety.

System limitations identified through asset management

All of the network development projects listed in Section 0 have been identified within JEN’s asset management framework:

- Section 5.1 outlines the network augmentation projects related to growth, demand and/or customer connections;
- Section 5.2 outlines the asset replacement projects that have an asset replacement cost greater than $200,000. These projects are identified through condition assessment as described in JEN's asset class strategies; and
- Section 5.4 outlines the grouped network asset replacement programs where the individual asset replacement cost is less than $200,000.

2.3 Demand Forecasting Methodology

Demand forecasting is critical to a network’s operation as it is a principal driver of capital expenditure. However, uncertainty always surrounds forecasts due to the inherent unpredictability of factors such as ambient temperatures, weather patterns and, in particular, loads.

Load growth can vary from year to year and is not uniform across the whole network. It is not unusual to find parts of the network growing at three or four times the average rate for the network as a whole, while other parts of the network can experience periods of no growth at all. The same observations apply for growth in embedded generation (including solar PV systems).

Best practice distribution demand forecasting

Jemena considers the following features necessary to produce best practice maximum demand, minimum demand, energy and customer number forecasts:

- **Accuracy and unbiasedness** – careful management of data (removal of outliers, data normalisation) and forecasting model construction (choosing a prudent model based on sound theoretical grounds that closely fits the sample data);
- **Transparency and repeatability** – as evidenced by good documentation, including documentation of the use of judgment, which ensures consistency and minimises subjectivity in forecasts;
- **Incorporation of key drivers** – including economic growth, population growth, growth in the number of households, temperature and weather-related data (where appropriate), growth in the number of solar PV systems, and growth in the numbers of electric vehicles, gas electrification, air conditioning and heating systems; and
- **Model validation and testing** – including the assessment of statistical significance of explanatory variables, goodness of fit, in-sample forecasting performance of the model against actual data, diagnostic checking of old models, out of out-of-sample forecast performance.

JEN also considers the following elements to be relevant to maximum demand and minimum demand forecasting:

- **Independent forecasts** – spatial (bottom-up) forecasts should be validated by independent system-level (top-down) forecasts, and both spatial and system-level forecasts should be prepared independently of each other. The impact of macroeconomic, demographic and weather trends are better able to be identified and forecast in system-level data, whereas spatial forecasts are needed to capture underlying characteristics of specific areas within the network. Generally, the spatial forecasts should be constrained (or reconciled) to system-level forecasts;

- **Weather normalisation** – correcting historical loads for abnormal weather conditions is an important aspect of demand forecasting. Long time-series weather and demand data are required to establish a relationship between the two and conduct weather correction;
- **Adjusting for temporary transfers** – spatial data must be adjusted for historical spot loads arising from peak load sharing and maintenance before historical trends are determined;
- **Accounting for distributed embedded generation** – noting that the network sees the net load, understanding the contribution that embedded generation has in reducing the underlying customer load;
- **Adjusting for discrete block loads** – large new developments, such as shopping centres and housing developments, should be incorporated into the forecasts, taking into account the probability that each development might not proceed. Only block loads exceeding a certain size threshold should be included in the forecasts, to avoid potential double counting, as historical demands incorporate block loads; and
- **Incorporation of the maturity profile of service area in spatial time series** – recognising the phase of growth of each zone substation depending on its age, and taking into account the typical lifecycle of a zone substation, helps to inform likely future growth rates.

In preparing our maximum and minimum demand forecasts, JEN engages an independent consultant for the system-level (top-down) forecasts. JEN prepares the spatial level (bottom-up) maximum demand forecasts internally, and our independent consultant prepares the spatial level minimum demand forecasts.

Section 4.3 discusses JEN's review of the 2022 forecasts, as presented in the 2022 DAPR.

System-level forecasts

JEN engaged Blunomy Consulting to conduct econometric modelling for the ten-year outlook period, to forecast maximum and minimum demand for the JEN network region as a whole (top-down).

The system-level maximum demand forecasts prepared by Blunomy include a summer and winter demand forecast for Jemena's total network at 10%, 50% and 90% probability of exceedance (**POE**) levels.

The system-level minimum demand forecasts prepared by Blunomy include summer, winter and annual demand forecasts for JEN's total network, at 10%, 50% and 90% POE levels.

The demand drivers the Blunomy forecast model uses include:

- An economic outlook for Victoria and JEN's supply area, as measured by the Victorian Gross State Product (**GSP**) growth projections (refer to Figure 2-3);
- Growth in customer numbers in local government areas and for Jemena's supply area, as measured by the number of inhabitants (refer to Figure 2-4);
- Solar PV generation capacity and battery storage based on analysis of historical installation rates and AEMO's 2023 Inputs Assumptions and Scenarios Report – Inputs and Assumptions Workbook[4] (refer to Figure 2-5, Figure 2-6 and Figure 2-7, which show the historic actual and neutral scenario forecast solar PV and battery storage for Jemena's supply area);
- Electricity prices, comprising network use of system (**NUoS**) charges, wholesale electricity costs and other costs such as retail margin applied to electricity sales, (refer to Figure 2-8 which shows the forecast Victorian real electricity prices used for Blunomy);
- Projections of uptake of electric vehicles based on AEMO's Integrated System Plan (**ISP**) inputs and assumptions, (refer to Figure 2-9 which shows the neutral scenario forecast uptake of electric vehicles);
- Projections of uptake of gas electrification based on Victoria's Gas Substitution Roadmap[5], including new policy made in July 2023 to phase out new residential gas connections from 1 January 2024, (refer to Table 2-4 which shows the forecast uptake of gas electrification); and
- Variation in temperature patterns (weather).

[4] Refer to AEMO | 2023 Inputs Assumptions and Scenarios Consultation

[5] Refer to Victoria's Gas Substitution Roadmap (planning.vic.gov.au)

Figure 2-3: Victorian economic growth projections

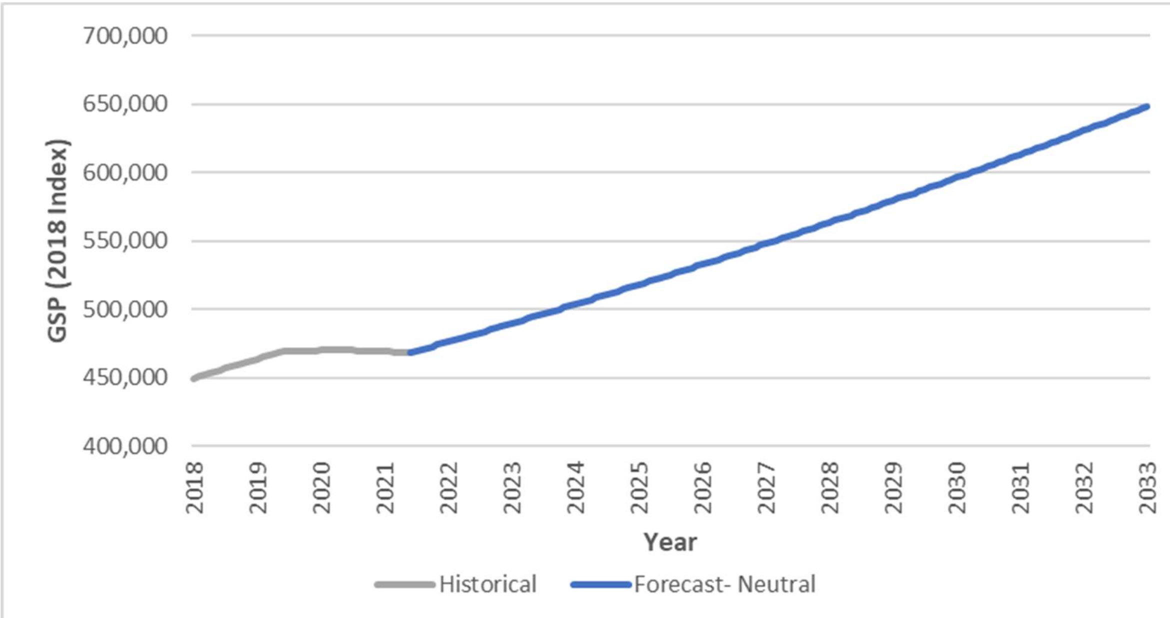


Figure 2-4: Projected annual population growth within Jemena's supply area

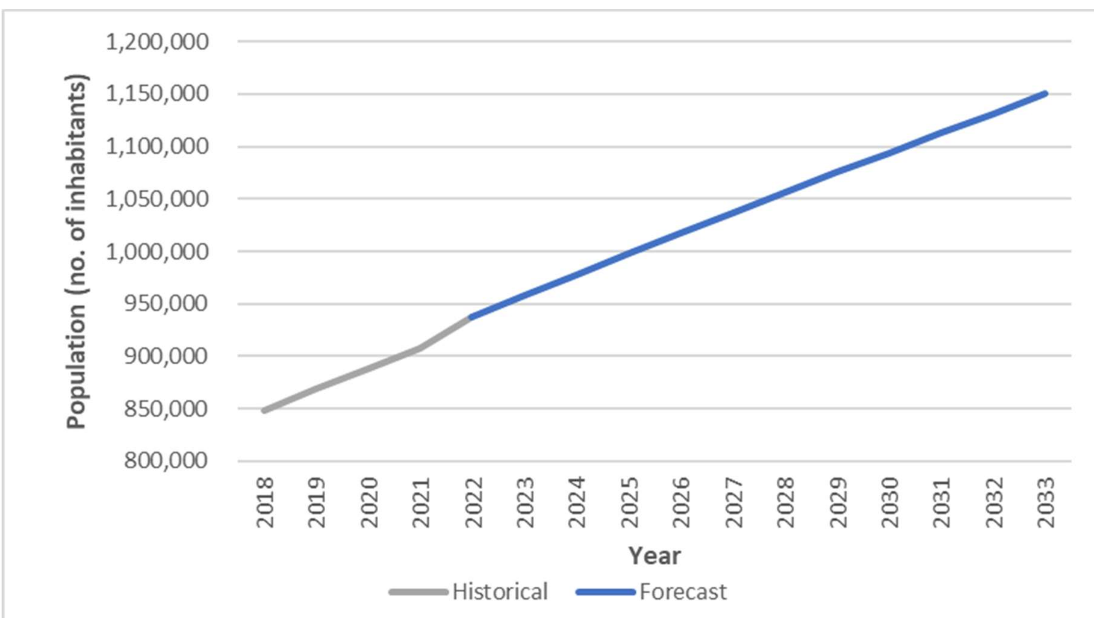


Figure 2-5: Cumulative capacity of installed solar PV systems within Jemena's supply area

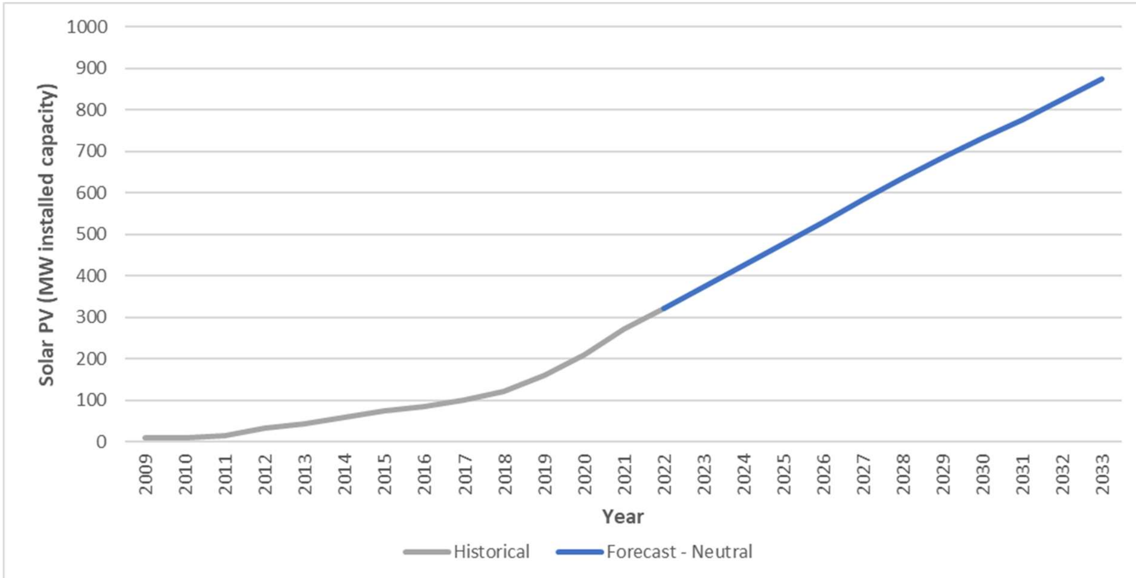


Figure 2-6: Forecast uptake of battery storage systems (MWh installed capacity) within Jemena's supply area

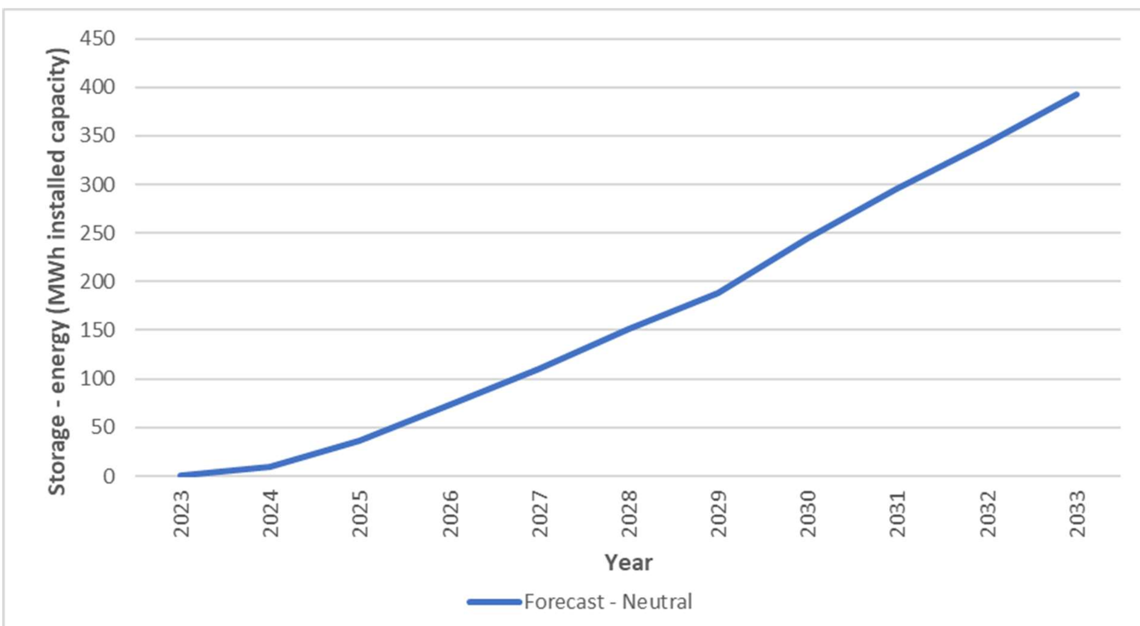


Figure 2-7: Forecast uptake of battery storage systems (MW installed capacity) within Jemena's supply area

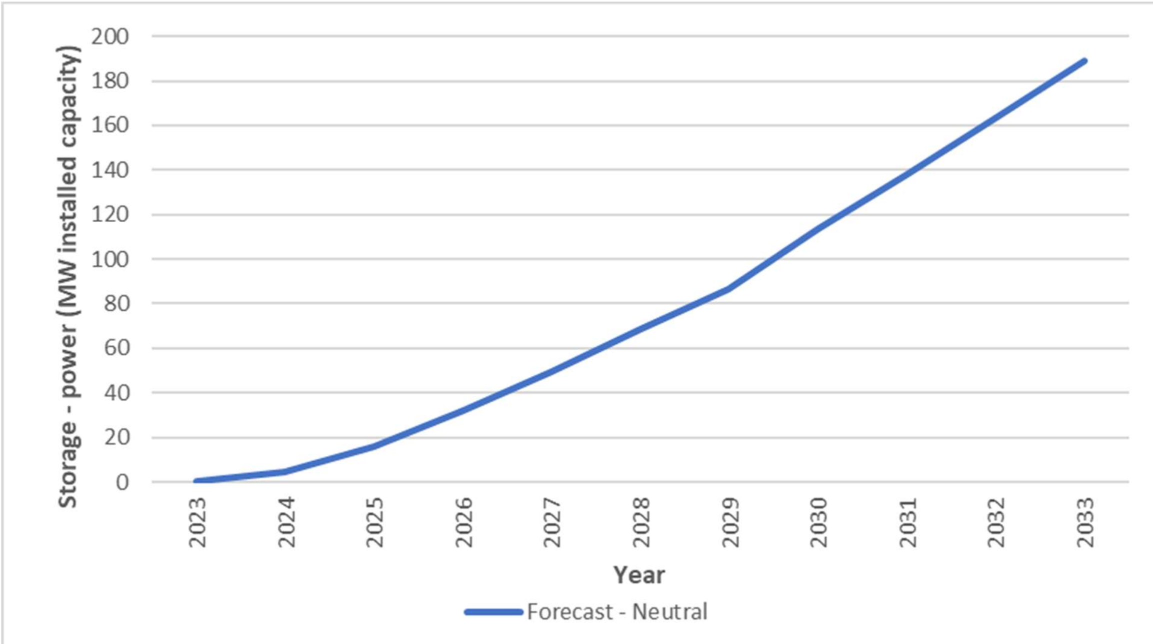


Figure 2-8: Forecast Victorian real electricity prices

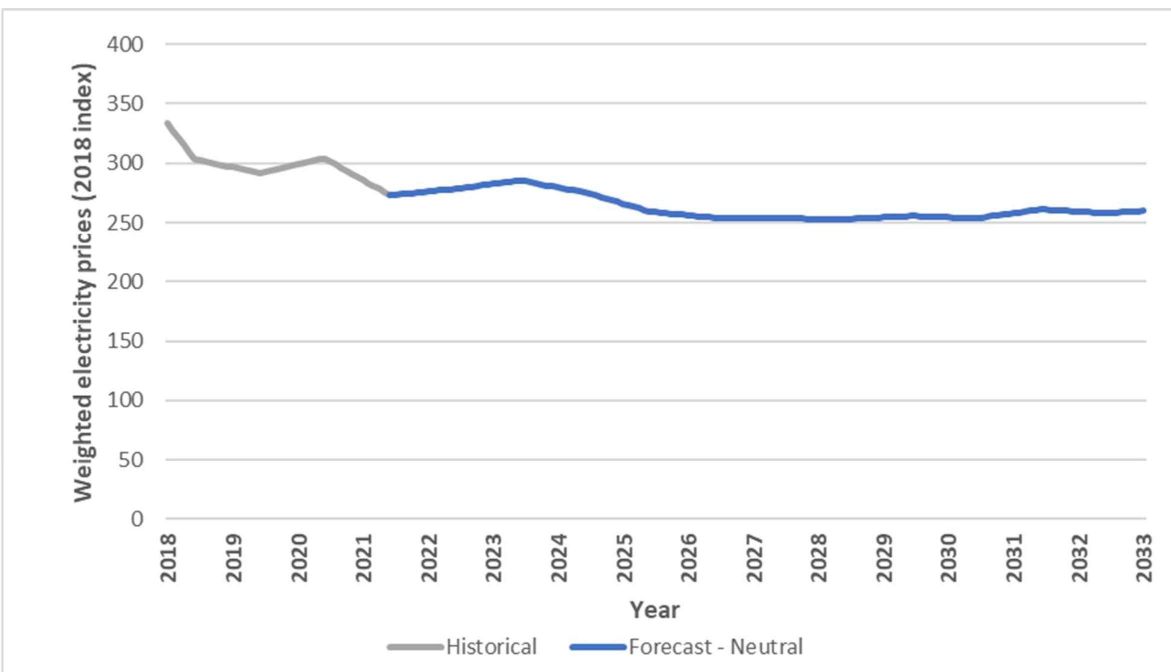


Figure 2-9: Forecast uptake of electric vehicles within Jemena's supply area

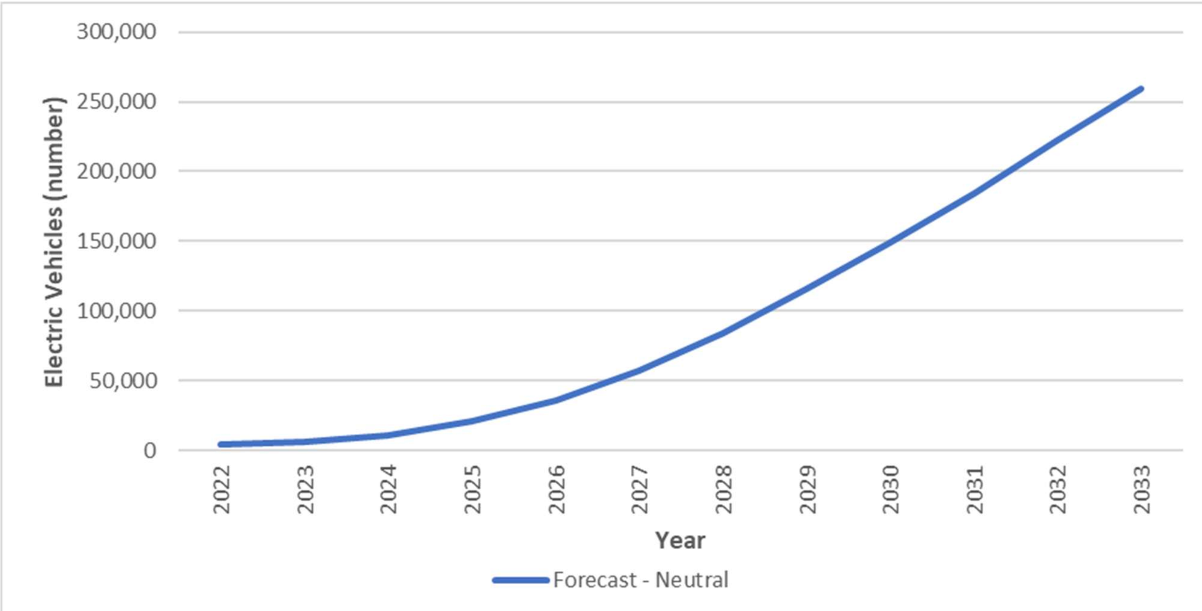


Table 2-4: Electrification of gas uptake by customer type, expressed as a percentage of JEN total customers

Scenarios	Electrification Residential & Commercial	Electrification Industrial
Low	30% of customers electrified in 2035 9% brownfield, 21% greenfield *(up from 25%)*	*NA*
Neutral	45% of customers electrified in 2035 24% brownfield, 21% greenfield *(up from 35%)*	15% of energy electrified in 2035
High	60% of customers electrified in 2035 *38% brownfield, 21% Greenfield*	25% of energy electrified in 2035

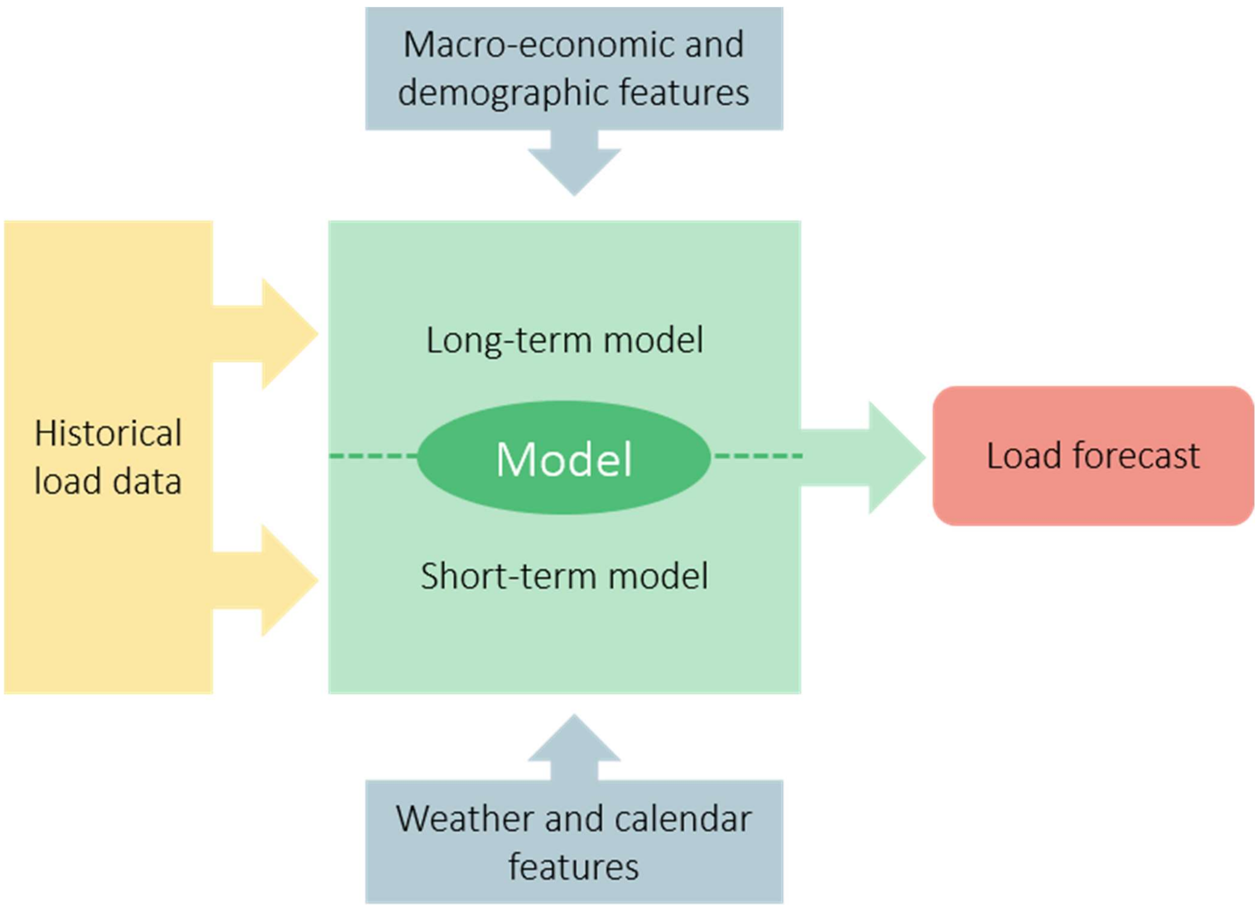
The model developed by Blunomy forecasts the demand as a 30-minute time series over the next 10 years (2023 to 2033) across a representative set of weather conditions and integrates the impact of new technologies (i.e. solar PV, battery storage and electric vehicles). Forecasting the complete demand time series (as opposed to forecasting the peak demand only) allows JEN to take into account the structural changes in the load patterns and the impact of new technologies on maximum and minimum demand and the energy at risk. It also allows JEN to integrate tariff considerations more easily.

The model is divided into two main components:

1. A short-term model that considers weather and calendar impacts on the load with a 30-minute temporal resolution
2. A long-term model that considers macro-economic and demographic impacts on the yearly trend in energy consumption.

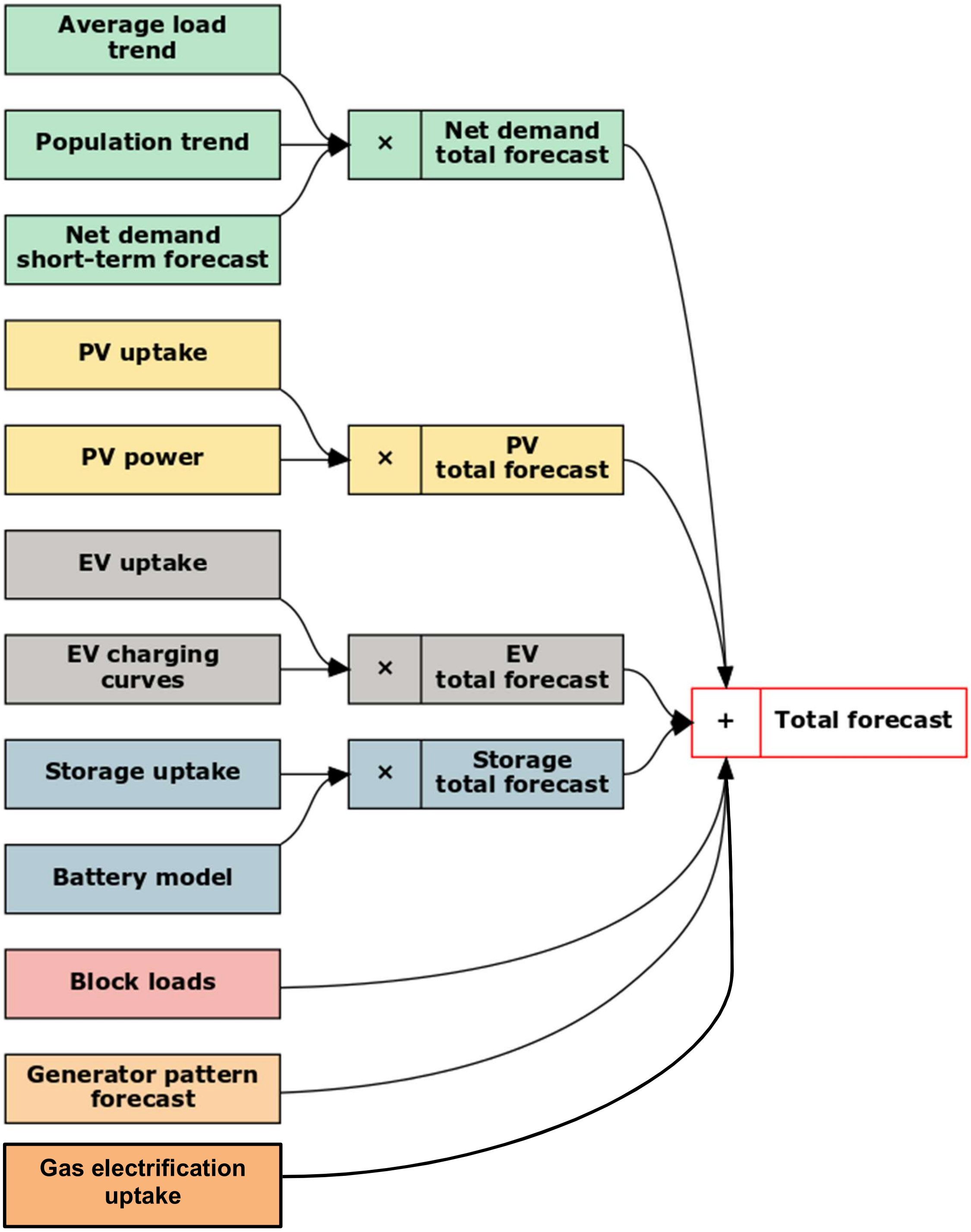
This approach is similar to the one used by the Monash Electricity Forecast Model and combines most of the factors influencing electricity demand. In 2015, the Monash Electricity Forecast Model was used by AEMO to produce the National Electricity Forecast Report. Figure 2-10 shows how the two components are brought together in Blunomy's load forecasting model.

Figure 2-10: Outline of Blunomy forecasting model



Blunomy's model predicts the demand and energy consumption on the network based on its current configuration and incorporates the impact of the emerging trends mentioned above. In practice, the forecast is built based on six different building blocks that are forecast separately and then added together to form the final forecast. Figure 2-11 illustrates this overall process.

Figure 2-11: Overall process of aggregating the net demand forecast building blocks



Electrification of gas model

There are also specific models for the electrification of gas, based on the assumptions stipulated in Table 2-4 derived from Victoria's Gas Substitution Roadmap[6].

The impact of the gradual electrification of gas on the network is assessed according to the availability of consumer gas data. For a given area e.g. Local Government Area (LGA), the model uses data on the amount of

[6] Refer to Victoria's Gas Substitution Roadmap (planning.vic.gov.au)

gas utilised for different gas appliances (hot water, space heating, cooking, etc) together with the connection count by type (residential, commercial or industrial).

Similar to how other technologies are calculated, like EVs or batteries, a short-term component (yearly) contribution of electrification is broadcasted within a greater long-term trend (spanning multiple years). The output of this calculation is a half-hourly time series consisting of the amount of possible electrified energy per feeder per customer class per use case.

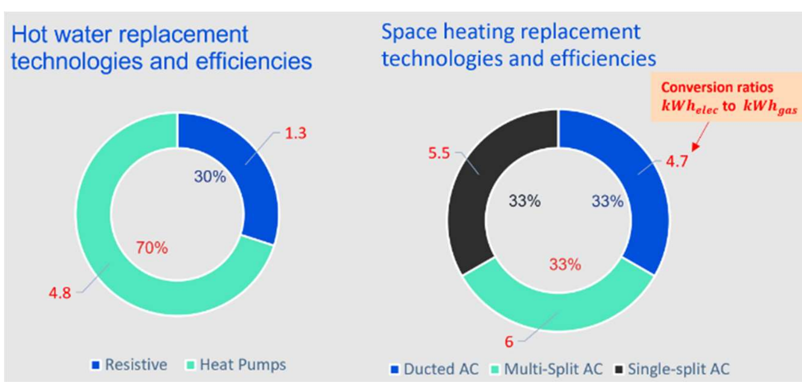
(Short term) predicts the yearly space heating / hot water profiles for residential and commercial groups of consumers. The maximum amount of electrifiable gas over the LGA is calculated and redistributed to feeders according to its share of maximum demand relative to other feeders in the same LGA. A split of gas utilised applied for each use case and customer type is based on external reports. To determine the gas profile, the gas consumption is assumed to follow the electrical load profile with the area under the curve scaled to the total electrified gas consumption over the common timeframe. This curve represents electricity consumed via the process of electrification for our base year.

(Long term) is comprised of two parts, the electrification of new customers (greenfield connections) and the gradual electrification of the existing customer base (brownfield connections). Greenfield connections are derived from the population growth to the asset, which proportionally grows the energy utilisation. A linear growth of electrified connections for brownfield connections is based on an assumed major rebuild/renovation rate that requires a planning permit.

For both the residential and commercial customer types, the dominant modes of gas consumption are between heating hot water and space heating. The gas contribution is split into the listed uses for each asset and each customer class before being scaled by an overall gas-to-electricity conversion efficiency for each use type. In this modelling, the gas uses are assumed to be the same for each customer class, but the proportion of each use can vary between classes. External sources and engineering assumptions are used to derive the splits between different customer gas uses. Residential splits are taken from Victoria's Substitution Roadmap, whereas the split for commercial customers is made more granular to account for the diversity of building types among commercial customers

The conversion efficiencies for both residential and commercial customers are shown in Figure 2-12, with commercial customers assumed to exclusively adopt heat pump technologies.

Figure 2-12: Conversion efficiencies



Having the total electrification energy budget enables the exploration of a variety of scenarios with the ability to set electrification targets on each use case, customer type and if the connection is greenfield or brownfield.

A separate method is utilised in determining the electrification contribution from industrial customers due to the lack of specific gas consumption records. To get an estimate of the customers, data is obtained from the National Pollutant Inventory[7], where the pollutants from all large customers are mapped to the closest industrial customer. The pollution output is converted into an equivalent amount of consumed fuel, where the fuel type is determined by the pollutant makeup. Specifically, the gas-burning customers are more likely to have a high

[7] Refer to https://data.gov.au/data/dataset/npi

CO/SO2 ratio (>20)[8]. The pollutants' emissions can be converted to an estimated energy content following findings from an existing study. A similar approach as with residential and commercial is adopted by associating the industrial customer to an industry and estimating the contribution of low-heat processes used by their industry[9]. The assumption used is that only low-heat processes (defined here as <250C) can be electrified via heat pump replacements, while high-heat processes require a shift towards hydrogen fuel to become green.

Similar to the residential and commercial cases, an electrical load profile is used as a proxy for an industrial customer's gas profile, where the total energy under the curve is scaled to be the amount of energy estimated from its pollution content.

Spatial-level forecasts

The spatial-level maximum demand forecasts prepared internally by JEN are built up from the feeder level to the zone substation level and then to the transmission connection terminal station level, taking into account diversity at each level of aggregation.

- **Phase 1: Feeder Forecast** – The previous year's recorded maximum demand is determined, corrected for abnormalities such as temporary load transfers, and adjustments to correspond to the 50% POE average daily temperature are applied to determine the forecast maximum demand starting point. The overall customer load changes (new or reductions) for each feeder (up to 5 years) are determined based on known new connections, large customer demand changes, and local and business developments. The underlying organic growth rate is applied to capture growth resulting from new air conditioning installations in existing dwellings, dual occupancy and minor new or modified loads that have not been allowed for in the overall customer load changes. Feeder forecasts are produced for a minimum of 5 years.
- **Phase 2: Zone Substation Forecast** – Similar to Phase 1, the zone substation maximum demand from the previous year is determined, corrected for abnormalities such as temporary load transfers, and adjusted to correspond to the 50% POE average daily temperature. Forecasts are then prepared by incorporating overall customer load changes (new or reductions), planned load transfers, and the organic growth rate. Overall customer load changes and load transfers are diversified before being included in the zone substation forecasts. Zone substation forecasts are produced for a minimum of 10 years.
- **Phase 3: Terminal Station Forecast** – Similar to Phase 2, the terminal station maximum demand from the previous year is determined, corrected for abnormalities such as temporary load transfers, and adjusted to correspond to the 50% POE average daily temperature. Forecasts are then prepared by incorporating overall customer load changes (new or reductions), planned load transfers, and organic growth rate. Overall customer load changes and load transfers are diversified before being included in the terminal station forecasts. Terminal station forecasts are produced for a minimum of 10 years.
- **Phase 4: Forecast Coincident Demand** – Forecasts of demand coincident to the forecast system level maximum demand is required for reconciliation to the top-down forecast. Coincident demand is determined by applying coincidence factors based on historical data to the non-coincident forecast developed in the preceding steps.
- **Phase 5: Forecast Reconciliation** – JEN's internal bottom-up forecasts are reconciled with the independent external top-down forecasts at the system level to account for factors such as changes in government policies, economic conditions or the uptake rates of solar PV, battery, electric vehicles and electrification, which are not captured by the bottom-up forecasts. The process for reconciling the forecasts to the system level involves determining the reconciliation factors at each network level and applying them to adjust the non-coincident bottom-up forecasts.

Spatial-level maximum demand forecasts are produced for summer and winter maximum demand periods for 10% and 50% POE conditions.

The spatial-level minimum demand forecast prepared externally by Blunomy is computed for each asset combining the net demand probabilistic forecast with the different technologies modelled. Monte-Carlo sampling across the weather-years is then applied to the forecast distributions to capture the probability of events. Spatial-level minimum demand forecasts are produced for summer, winter and annual minimum demand periods for 10% and 50% POE conditions.

[8] Refer to https://arena.gov.au/assets/2019/11/appendices-renewable-energy-options-for-industrial-process-heat.pdf

[9] Refer to https://www.energycouncil.com.au/analysis/electrification-heat-discussion-paper-released/

JEN adopts its spatial forecasts for network planning, due to the planning need for forecasts at the feeder and zone substations level. Accurate spatial forecasts are critical to achieving outcomes that are consistent with the National Electricity Objective (**NEO**), the Regulatory Investment Test for Distribution (**RIT-D**) requirements, and the capital expenditure objectives in the NER. Inaccurate demand forecasts will result in energy-at-risk forecasts that are biased downwards or upwards, depending on whether the forecast demand is higher or lower than actual demand. Consequently, without accurate spatial forecasts, efficient investment would not occur and customers would be exposed to uneconomic outcomes, including increased risk of supply interruptions or generation curtailment.

In preparing the impact of customer load changes on its spatial forecasts, JEN considers proposed major industrial and commercial developments, predicted housing and industrial lot releases, and proposed embedded generation. Other items, such as economic forecasting, council planning and various Precinct Structure Plans conducted by the Metropolitan Planning Authority,[10] are also taken into account.

The principal developments driving significant maximum demand growth or minimum demand decline in specific locations on the JEN network are outlined in Table 2-5.

Table 2-5: Key JEN Network Developments

Zone Substation	Description
Broadmeadows	Continued installation of new customer solar PV systems on an already relatively high penetration level.
Coburg North	Development of new commercial and industrial customers
Coolaroo	Continued expansion of URD estates within the Greenvale area Continued installation of new customer solar PV systems on an already high penetration level.
Fairfield	Redevelopment of the Amcor site in Fairfield to multiple high-rise residential and office buildings
Flemington	New high-rise residential and office buildings within the Flemington area
Footscray East/ Yarraville	New high-rise residential and office buildings within the Footscray Central Activities District
Kalkallo and Somerton	Development of URD and industrial estates in the Kalkallo, Craigieburn and Mickleham areas covered by the Northern Growth Corridor Continued installation of new customer solar PV systems on an already high penetration level.
North Essendon	New high-rise residential and commercial development in Mason Square, Hall Street, Moonee Ponds, and a proposed Moonee Valley Racecourse redevelopment
Sunbury	Continued URD estate developments Continued installation of new customer solar PV systems on an already relatively high penetration level.
Sydenham	Continued URD estate developments Continued installation of new customer solar PV systems on an already high penetration level.

Transmission connection point forecasts

Forecasts for the transmission connection points are explicitly included in the TCPR.

10 See http://www.planmelbourne.vic.gov.au for the Plan Melbourne report.

2.4 Network Planning Methodology

This section provides an overview of the network planning methodology applied by JEN to assess network limitations and identify proposed and preferred solutions to mitigate network limitation risks.

2.4.1 Planning standards

JEN is required to conduct its planning in accordance with the NER and the EDCoP. Clause 5.13 of the NER requires JEN to:

- Prepare forecasts, covering the forward planning period, of maximum and minimum demands for transmission-distribution connection points, zone substations, subtransmission lines and primary distribution feeders (where practicable);
- Identify, based on the outcomes of the forecasts, limitations on its network;
- Identify whether corrective action is required to address any system limitations and, if so, identify whether it is required to carry out the requirements of the regulatory investment test for distribution (RIT-D)[11] and demand-side engagement obligations; and
- Take into account any jurisdictional legislation.

Clause 19.2.1(b) of the EDCoP requires Jemena to use best endeavours to 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;
- To minimise the risks associated with the failure or reduced performance of assets; and
- In a way that minimises costs to customers taking into account distribution losses.

To satisfy these obligations, JEN applies both probabilistic and deterministic methodologies to the planning of its network.

2.4.2 Probabilistic method

The probabilistic method is applied to network assets with the most significant limitations and associated augmentation costs, including:

- Transmission connection points;
- Subtransmission lines;
- Zone substations; and
- High-voltage (**HV**) feeders that have been identified through a deterministic screening assessment as outlined in Section 2.4.3.

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 (**EUSE**), which is defined in terms of megawatt hours (**MWh**) per annum.

[11] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-investment-test-for-distribution-rit-d-and-application-guidelines

In the case of load at risk, EUSE estimates the:

- Long-term probability-weighted, average annual energy demanded by customers but not supplied; and
- Future degradation of electricity supply reliability as demand grows or changes.

The EUSE measure is then translated into an economic value, suitable for cost-benefit analysis, using the value of customer reliability (**VCR**) (in $/MWh), which reflects the economic cost per unit of energy not supplied.

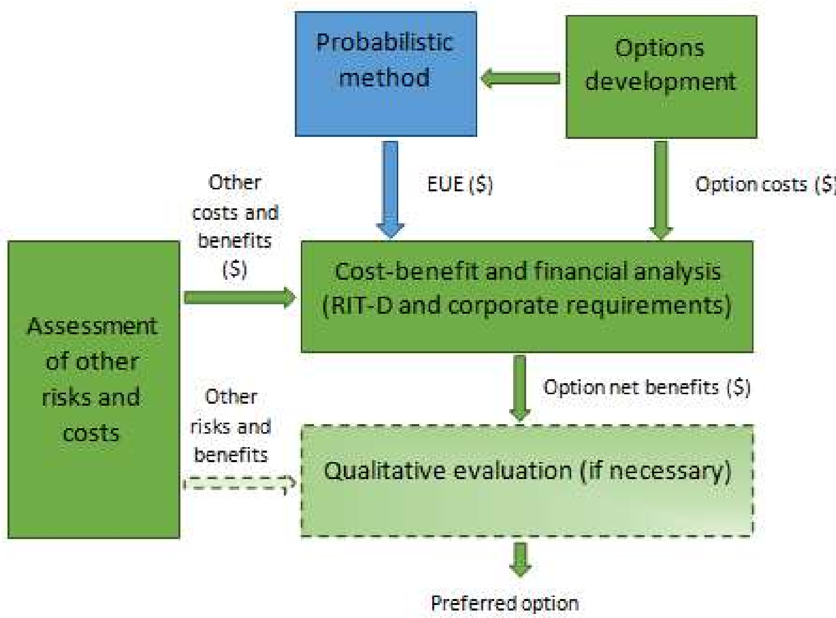
In the case of generation at risk, EUSE estimates the:

- 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 EUSE measure is then translated into an economic value, suitable for cost-benefit analysis, using the value of DER (**CECV**) (in $/MWh), which reflects the economic cost per unit of generation curtailed.

Figure 2-13 shows how EUSE is used within the broader context of network planning.

Figure 2-13: Overview of the probabilistic approach and the broader network-planning task



To determine an augmentation option's economic benefits:

- The EUSE 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 EUSE, relative to the do-nothing case establishes the augmentation option's economic benefit; and
- The economic benefit is compared with 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 changes to existing service target performance incentive scheme (**STPIS**) measures, electricity losses and asset replacement requirements. Unquantifiable risks and benefits can be qualitatively considered when selecting the preferred option.

The probabilistic planning method is made up of four key stages:

3. Network limitation assessment, which involves determining the extent of network constraints for various network contingency and demand forecast scenarios;
4. Energy at risk analysis, where the maximum energy that is at risk of not being supplied or curtailed due to these network constraints is determined;
5. **EUSE** calculation, which considers the probability of the forecast demand and network condition (contingency) occurring; and
6. Cost of EUSE, where the EUSE is transformed into a dollar cost by multiplying the **VCR** in the case of load at risk, or the **CECV** in the case of generation at risk, by the expected unserved energy.

2.4.2.1 Network limitation assessment

A network limitation is assessed by comparing the peak asset loading, under a range of different scenarios and network contingencies, with the asset's (import or export[12]) rating for each year in the forward planning period. The comparison identifies the extent of the asset overload that will occur without corrective action.

A series of inputs and assumptions are associated with the probabilistic method's limitation assessment stage:

- Maximum and minimum demand scenarios (annual, summer and winter), which form a critical input for defining the peak asset loading, and incorporate the:
- Probability of exceedance (**POE**), which defines the likelihood that the actual maximum demand (and resulting EUSE) will differ from the forecast due to more extreme or benign weather conditions; and
- Economic growth assumptions, which define the likelihood that the actual demand (and resulting EUSE) will differ from the forecast due to different economic growth outcomes.
- Levels of embedded generation and demand-side support, which can affect asset loading. However, without the necessary network support contracts, large, metered embedded generation cannot be relied on and, for the DAPR limitation assessments, is assumed to not be generating and netted out of the demand forecast. By comparison, behind-the-meter customer embedded generation is not netted out of the demand forecasts.
- Contingencies, which can significantly affect asset loading. The DAPR assessments consider loading for both system-normal conditions and following the most credible single contingency.
- Pre and post-contingent operator actions, which can affect asset loading, the import and export ratings, and therefore the EUSE. Operator action considerations incorporate:
  - Reasonable expectations of what may occur at an operational level given the relevant contingent conditions, and allowing for:
    - Available reactive plant switching and control schemes to operate appropriately; and
    - The use of available load transfer capacity that is consistent with the asset's rating assumptions.
- Asset rating (import and export), which typically defines the thermal loading limit and is selected to reflect the assumed contingency conditions; and
- Power quality obligations, which under some circumstances, such as steady-state voltage limitations, can set a smaller loading limit for the asset rating.

Power flow modelling is used to determine the relationship between asset loading and contingency conditions, particularly in circumstances where the loading share between parallel assets is uneven, or the loading limit is defined by a power quality obligation.

2.4.2.2 Substation 'N secure' rating

Power system security refers to the ability to operate the power system in a secure state, such that a contingency event (loss of a network element due to a fault or equipment failure) will not result in cascading loss of supply or immediate overload of network assets that cannot be managed without causing asset damage.

[12] Import ratings are used for forward power flows (i.e., flows downstream towards customer loads). Export ratings are used for reverse power flows (flows upstream towards the transmission point of connection).

In cases where the forecast maximum (or minimum) demand is approaching the 'N secure' import (or export) rating of the zone substation, operational instructions are in place to manage the N risk under peak loading conditions. These typically require the operators to split the zone substation bus by opening the bus tie circuit breaker when the station loading exceeds a predetermined limit or transferring load or generation away to an adjacent zone substation before the actual demand reaches the station N secure rating limit.

2.4.2.3 Energy at risk analysis

Energy at risk:

- Represents the total energy that is at risk of not being supplied or curtailed under contingency events, particularly around the maximum demand period, or the minimum demand period when the minimum demand is negative;
  - Can be approximated by using a net load duration curve that reflects the maximum or minimum demand scenario for a given transmission connection terminal station, zone substation or HV feeder asset; and
- Is calculated as the amount of energy exceeding the net load duration curve's asset loading limit, where the loading limit is typically the asset's N-1 import (or export) rating. The net load duration curve is typically based on historical hourly net load data scaled to the forecast maximum demand.

Energy at risk is calculated for each maximum and minimum demand scenario and contingency for each year of the outlook period.

Figure 2-14 shows a sample load duration curve with a dashed horizontal line representing the import load limit of a specific contingency. Figure 2-15 shows the same figure, magnified around the part of the load duration curve closest to the maximum demand. This effectively illustrates the energy at risk calculation, which is represented by the area under the net load duration curve and above the import load limit.

Figure 2-14: Load duration curve and import load limit relationship

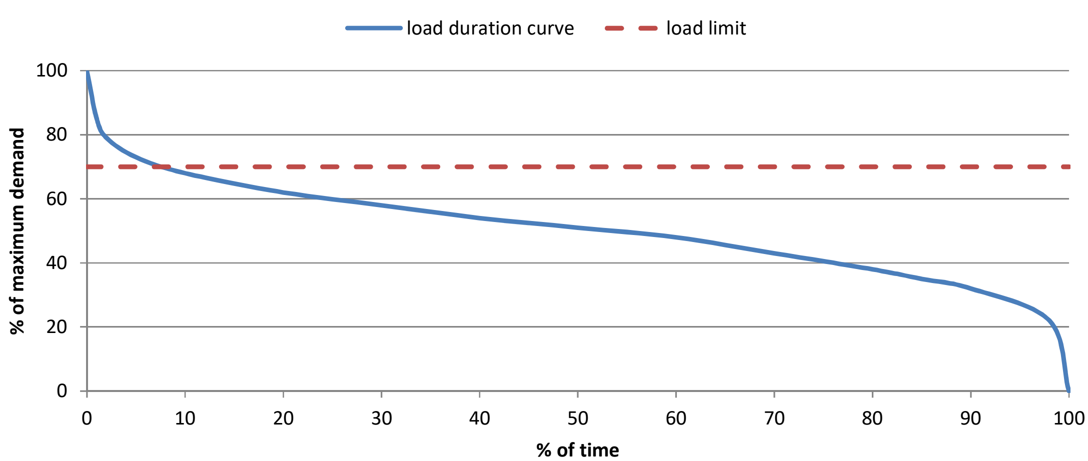
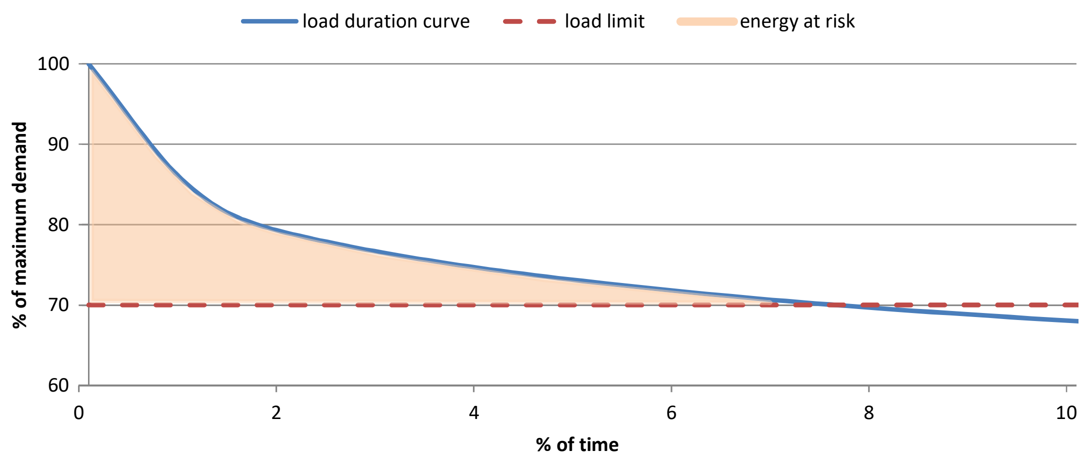


Figure 2-15: Energy-at-risk calculation for the area of the load duration curve above the import load limit



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

- Reflects the maximum or minimum demand forecast scenario; and
- Is based (for the DAPR assessments) on an average of the past ten years of historical demand data at the transmission connection terminal station level, measured on an hourly or half-hourly basis.

2.4.2.4 Expected unserved energy (**EUSE**) calculation

For a specific maximum or minimum demand scenario and contingency, the EUSE measure in megawatt hours (MWh) is the product of the:

- Energy at risk calculated for a given network state; and
- Probability of being in that network state.

In other words, it is the probability that the network will be in a particular condition (system normal or contingency) for a given maximum or minimum demand scenario.

Total EUSE

The total annual EUSE measure is the sum of that year's EUSE measures for each network state.

The total $EUSE = \sum(E@R_{c,d} \times p_c \times p_d)$, across all possible states of c and d; where:

— $E@R_{c,d}$ represents the energy at risk measure for a given state,
— *c,* is the contingency condition with the probability of being in that state, p_c, and
— *d*, is the maximum or minimum demand scenario with the probability of that scenario, p_d.

The assumptions associated with calculating the total EUSE are:

- The probability weighting maximum or minimum demand scenarios – for the planning assessments, JEN has weighted two maximum and minimum demand scenarios. The 10% POE scenario is weighted 30% and the 50% POE scenario is weighted 70%; and
- 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 total number of hours in a year (8,760 hours).
- These parameters are selected to represent the relevant contingency conditions assumed in the network constraint analysis stage. For the DAPR, the contingency probabilities applied include the:

— Transformer outage probability, which is 0.217%, and comprises an outage frequency of one outage per transformer every 100 years and lasting an average duration of 2.6 months per outage;
— Subtransmission line outage probability, which is 0.1 outages per kilometre of line length per year and lasting an average duration of 4 to 8 hours (depending on location) per outage;
— HV overhead feeder outage probability, which is 0.2 outages per kilometre of feeder length per year and lasting an average duration of 2 to 4 hours (depending on location) per outage; and
— HV underground feeder outage probability, which is 0.1 outages per kilometre of line feeder length per year and lasting an average duration of 4 to 8 hours (depending on location) per outage.

Cost of EUSE for load

The cost of EUSE for load is established by multiplying the EUSE calculation by an appropriate value of customer reliability (**VCR**), where the VCR is:

- The most appropriate for the assets being assessed and the customer base they supply; and
- Based on values derived and published by the Australian Energy Regulator[13].

For the DAPR assessments, Jemena has calculated a VCR of $45,006/MWh (in 2023 Australian dollars) to be applied to all limitation assessments. This VCR was developed using the AER's value of customer reliability review and applying Jemena's customer energy consumption composition, comprising an approximate 36% residential, 41% commercial and 23% industrial split.

Cost of EUSE for generation

JEN has not published these values in this DAPR as the method and value for determining generation curtailment is still being assessed. It is intended to publish these values in next year's DAPR using the AER's CECV methodology[14].

2.4.2.5 Calculation of subtransmission loop EUSE calculation

The energy at risk for subtransmission loops is determined as follows:

- Conduct network studies to determine the flow observed on the remaining in-service subtransmission lines, for an outage of one line under maximum and minimum demand conditions;
- Where the post-contingent flow on the remaining in-service lines exceeds 120% of the line import (or export) rating, determine the pre-contingency load (or generation) reduction required such that the post-contingent flow does not exceed 120% of the line import (or export) rating. To determine the expected energy at risk, this pre-contingency load (or generation) reduction has a probability of one; and
- The expected energy at risk to reduce flow for the remaining in-service line from 120% to 100% of the line import (or export) ratings is determined from the additional load shed (or generation curtailment) required and the contingency probability for the relevant line outage.

In practice, load shedding (or generation curtailment) before an outage would be the last resort for JEN operations staff. However, this must be balanced against the risk of damage to the remaining in-service line if an outage were to occur, resulting in a flow significantly above the line import (or export) rating.

2.4.2.6 Treatment of losses

Increases or decreases in power losses are accounted for in the economic evaluation of network augmentation and asset replacement projects. Network power loss changes are inherently accounted for through power system analysis as the change in network loading due to network impedance changes of newly installed, removed or altered assets. The benefits, positive or negative, of power loss changes are included in the benefits calculations,

13 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

14 https://www.aer.gov.au/industry/registers/resources/guidelines/customer-export-curtailment-value-methodology

but they are not separately reported in our assessments as they generally have a much smaller financial value compared with the value of EUSE.

Power losses are typically only material in areas of the network supplying long subtransmission circuits or feeders, which are scarce but do exist in some of the more rural areas to the north of our network.

Since power losses are typically immaterial in value within our network, and are generally insufficient to justify augmentations without additional identified benefits, JEN does not generally approach a potential reduction in power losses as an investment driver in itself. Where network losses do have a material impact, the benefits of augmentation or asset replacement are commonly identified through other network supply risks, such as expected unserved energy assessments, and the benefits are identified by comparing the reduction in expected unserved energy that each credible option can deliver.

Similarly, when considering augmentations to increase the power factor at customer supply points, such as installing new capacitor banks at zone substations, the reduction in network losses due to the removal of reactive power flows from the bulk transmission supply point will be reflected in the increased capacity to meet customer demand, reducing load curtailment and any expected unserved energy.

For new feeders, or when upgrading a section of an existing feeder to increase its capacity, JEN selects conductors, from its agreed standard conductors, that are optimised for the expected maximum demand the feeder is intended to carry in the forward planning period. A conductor with lower resistance will incur lower conductor losses, and lower heating for a given current rating, which subsequently allows for a higher current rating. While oversizing conductors will invariably lead to lower power losses, the additional asset and installation costs are rarely offset by the reduction in power losses. JEN maintains a set of standard conductors for its feeder designs to minimise the carrying of spares.

For power transformers, JEN has standard designs that have been selected based on their applicability and suitability for the network and that are manufactured in accordance with Australian standards. In their offers to supply a power transformer, manufacturers will give a guaranteed load and no load loss. JEN will capitalise the guaranteed losses and so determine the economic advantages of the transformers offered. Capitalisation of losses will be based on guaranteed losses at the required power rating. The selection of conductor material by the transformer manufacturer will directly impact the guaranteed losses.

For distribution transformers, JEN conducts a cost-of-life assessment that considers the economic benefit of lower transformer losses against the upfront costs, in accordance with the ENA Specification for Pole Mounting Distribution Transformers (ENA Doc 007-2006).

2.4.3 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;
- Is used to screen for HV feeders where loading is forecast to exceed the maximum safe loading limit. Probabilistic planning is then applied to determine the preferred solution to the identified HV feeder constraint and its optimal timing;
- Is used for distribution substations and associated LV networks; and
- Makes no allowance for contingent conditions because these assets generally have a lower standard of load control and monitoring.

The deterministic planning criteria are set to approximate the prudent timing for when additional network or non-network capacity is required, and are predominantly based on two key drivers:

7. Maintaining the safe operation of assets; and
8. Maintaining the supply reliability and quality provided by these assets under system normal conditions (with all network assets in service).

Three key assumptions and criteria are associated with this method:

9. The maximum or minimum demand forecast scenario, where only the 10% POE scenario is applied;
10. The network condition being considered. Given that this method only applies to HV feeders and distribution substations, only the system normal condition is assessed; and
11. The loading limit represents the maximum permissible loading relative to a reference import (or export) rating for the assumed maximum (or minimum) demand forecast. For the DAPR assessments, a loading limit of 100% of the HV feeder's import (or export) rating has been applied to the deterministic assessment methodology.

The deterministic method's risk/cost trade-off can be viewed in terms of the relationship between the maximum (or minimum) demand scenario's probability of exceedance assumption, the asset loading, and the assumed import (or export) rating.

The determination of the maximum safe loading limit is based on the conductor's and/or cable's maximum operating temperature, at which point these assets deteriorate rapidly to an unacceptable level, or a statutory clearance limit is expected to infringe on the asset's safe operation. A fixed perpendicular wind speed of 0.6 m/s is typically assumed in limit determination calculations.

2.4.4 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, subtransmission 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 against the associated export rating for each network asset.

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[15];
- **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.

15 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.

3. Network Performance

This section describes the service target performance incentive scheme (**STPIS**) set by the Australian Energy Regulator (**AER**), and the reliability performance indicators used to assess Jemena's network performance. It includes a summary of how Jemena's electricity network has performed against these targets, presents forecast performance targets, and summarises corrective action being taken to ensure appropriate levels of performance are maintained.

This section also considers Jemena's power quality obligations, comprising steady state voltage, voltage variations, harmonics, unbalance and flicker. Both historical and forecast power quality performance for Jemena's network is considered.

3.1 Network Performance Indicators

Delivering a reliable electricity supply to our customers is core to Jemena's business. In line with the STPIS, JEN continuously monitors its network performance using the international reliability measures and standards presented in Table 3-1. Using these indicators to track and compare our performance enables us to identify network performance issues and initiate required investments to maintain appropriate reliability levels.

Table 3-1: Reliability measures and standards

Index	Measure	Description
System Average Interruption Duration Index (SAIDI)	Average off-supply minutes per customer	The average minutes 'off supply' that a customer could expect to be without electricity per year. The measure in STPIS relates to unplanned outages (excluding planned) where the electricity supply was interrupted for more than three minutes. SAIDI is calculated as the total unplanned customer minutes off supply divided by the total number of connected customers averaged over the year.
System Average Interruption Frequency Index (SAIFI)	Average number of interruptions per customer	The average number of occasions per year when each customer could expect to experience an unplanned interruption. SAIFI is calculated as the total number of customer interruptions divided by the total number of connected customers averaged over the year. SAIFI excludes momentary interruptions of three minutes or fewer.
Momentary Average Interruption Frequency Index (MAIFI)	Average number of momentary interruptions per customer	The average total number of momentary interruptions (three minutes or less duration) that a customer could expect to experience in a year. MAIFI is calculated as the total number of customer interruptions of three minutes or less duration, divided by the total number of connected customers averaged over the year.

3.2 Historical Network Performance

In the 2021-2026 Electricity Distribution Price Review (**EDPR**), the AER changed the regulatory period from calendar years to financial years. The AER extended the 2016-2020 STPIS for six months to 30 June 2021 with a set of performance targets for the transitional period from 1 January to 30 June 2021 (H1 2021). Network performance monitoring and reporting are in financial years from July 2021.

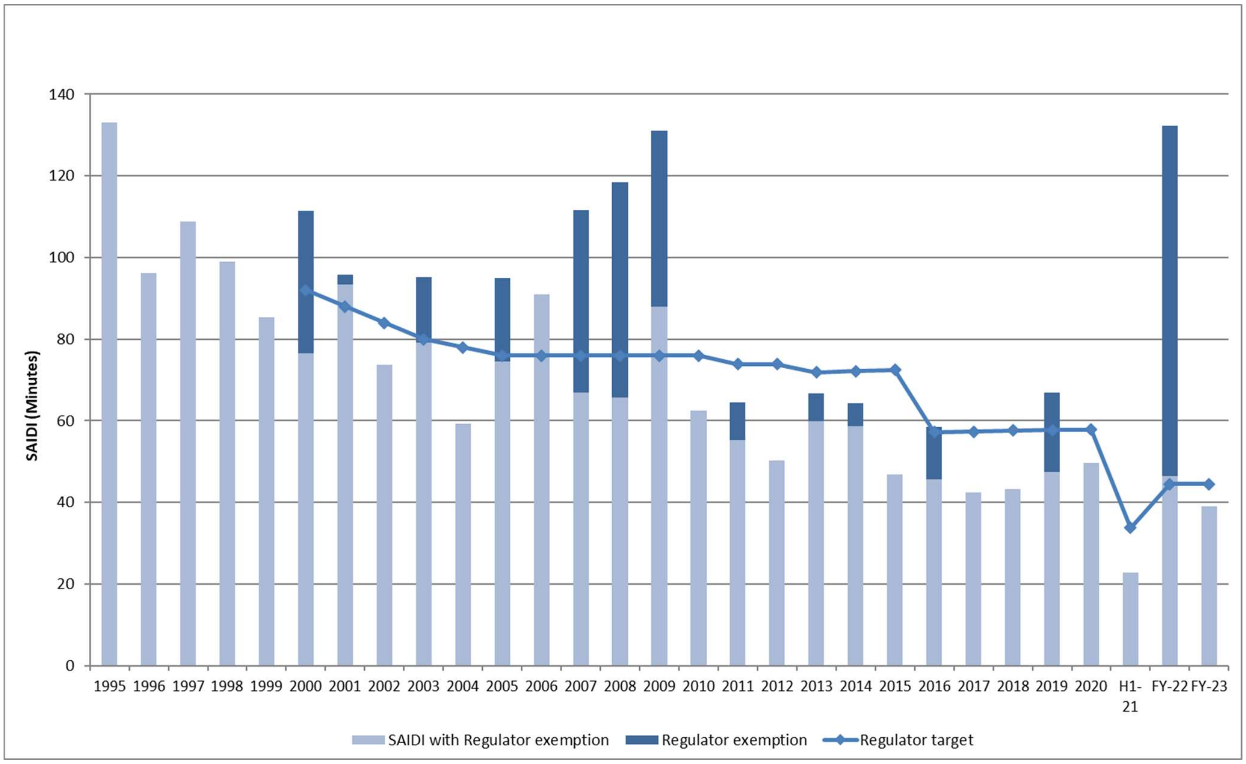
JEN continually monitors network performance and internally reports actual performance against STPIS targets every month. There are six reliability measures and one customer measure in STPIS. All the performance targets have been set based on the average performance of the five years before the EDPR submission. All aspects of

JEN's business, from asset management and investment strategies to network control and monitoring, contribute to network performance and have continuously improved, resulting in very tight targets for the current regulatory period 2021-2026. Six of seven STPIS performance measures met the targets in the 2022-23 financial year. The comparison is shown in Table 3-2.

Overall, the network performance in 2022-23 outperformed the regulatory performance targets. Both Network SAIDI and Network SAIFI achieved their lowest levels since 1995.

Figure 3-1 shows JEN's historical network performance for unplanned SAIDI (between calendar year 1995 and financial year 2023) compared with the AER's performance targets.

Figure 3-1: Historical unplanned SAIDI network performance (CY 1995-FY2023)



The comparison between JEN's actual and target STPIS reliability measures is set out in Table 3-2.

Table 3-2: STPIS reliability financial year 2022-23

Feeder Classification	Performance Measure	2021-22 Actual	2021-22 Target	Variance
Urban (after removing excluded events and Major Event Days (**MED**))	Unplanned SAIDI	38.639	43.914	-12%
	Unplanned SAIFI	0.672	0.728	-8%
	MAIFI	0.921	0.952	-3%
Rural (after removing excluded events and MED)	Unplanned SAIDI	42.540	48.440	-12%
	Unplanned SAIFI	0.772	0.743	4%
	MAIFI	1.141	1.416	-19%

The performance measure used in assessing STPIS Customer Service is call centre performance (telephone answering) where the per cent of fault calls forwarded to operators were answered within 30 seconds.

The comparison between JEN's actual and target STPIS customer service measure is set out in Table 3-.

Table 3-3: STPIS customer service financial year 2021-22

Measure	2021-22 Actual	2021-22 Target	Variance
Telephone answering	80.453%	73.263%	9.8%

An explanation for the variance is outlined below.

Three of the six STPIS performance measures in Table 3–2 show a variance of greater than 10 per cent. The remaining three variances Urban Unplanned SAIDI, Rural Unplanned SAIDI and Rural Unplanned MAIFI also relate to better-than-target levels of performance. The main factors contributing to the favourable performance are:

- JEN's more stringent vegetation management practices arising from legislative changes to the Electricity Safety (Electric Line Clearance) Regulations in 2010 and JEN's effective condition-based asset replacement, prudent network augmentation and maintenance of current network performance standards; and
- Mild temperatures experienced in the 2022-23 summer; and
- JEN's investment in an advanced distribution automation system called Fault Location Isolation and Service Restoration (**FLISR**). FLISR analyses the network in real time and determines the optimum alternate supply to healthy feeder sections after fault isolation to minimise the duration of customers off supply hence improving service reliability and availability.

The STPIS Customer Service performance measure outcome in Table 3–3 shows a variance of close to 10 per cent compared to JEN's target. This favourable variance is a result of efforts to respond to customer feedback and expectations in light of the call centre performance of similar organisations.

3.3 Network Performance Targets

STPIS is intended to balance incentives to reduce expenditure with the need to maintain or improve service quality. It provides an incentive for a DNSP to maintain and improve the reliability of network services.

The STPIS that the AER has applied to Jemena comprises the following two mechanisms:

12. A service factor (**s-factor**) adjustment to annual revenue allowances, rewarding/ penalising DNSPs for better/ worse performance compared with predetermined (and approved) targets for supply reliability and customer service.
13. A guaranteed service level (**GSL**) component whereby customers are paid if they experience service below a predetermined level.

JEN will maintain the performance levels that occurred during the 2021-2026 regulatory period, with performance targets set based on average actual network performance measured between financial year 2015-16 and 2019-20, as per the AER's methodology.

Table 3-3 and Table 3-4 present JEN's annualised performance targets for the 2021-2026 financial year period as agreed by the AER.

Table 3-3: 2021-2026 network performance targets

Measure	Urban	Rural – Short
Unplanned System Average Interruption Duration Index (SAIDI)	43.914	48.440
Unplanned System Average Interruption Frequency Index (SAIFI)	0.728	0.743

Measure	Urban	Rural – Short
Momentary Average Interruption Frequency Index (MAIFI)	0.952	1.416

Table 3-4: 2021-2026 network customer service target

Measure	Network
Telephone answering: % of calls will be answered within 30 seconds	73.263

Details of the STPIS to apply to Jemena for 2021-2026 can be found on the AER website[16].

3.3.1 Forecasting network performance

JEN's capital and operational expenditure plans are based on the principle of maintaining network reliability performance. This principle will continue in the current regulatory period as per JEN's submission to the AER's Electricity Distribution Price Review (**EDPR**) 2021-26[17]. Network performance forecasts are therefore prepared following the same principle of aiming to meet the performance targets over the long term.

While reliability performance is in principle a function of asset conditions, operational and maintenance practices, and network investment, ambient weather is a primary driver of network demand and capability and cannot be forecast. With the capital and operational expenditure as nominated in Jemena's submission for the 2021-26 regulatory period, JEN forecasts that it will meet or exceed the network performance targets proposed in the submission that has been released in the AER's Final Determination in 2021.

3.4 Network Performance Corrective Action

Network performance improvement initiatives differ from traditional network augmentations or asset replacements. Where network augmentation and asset replacement traditionally focus on proactively developing the network to meet demand growth and maintain a reliable service, network performance improvements can either be forward-looking or more reactionary. Fault Location, Isolation and Supply Restoration (FLISR) have been implemented on Jemena's Outage Management System to reduce fault impacts on customers for example.

Network performance improvement initiatives undertaken by Jemena typically include:

- Installing tie-lines between heavily loaded radial/spur feeders that lack emergency transfer capacity;
- Optimising feeder loads and customer numbers to minimise fault impacts;
- Installing remote monitoring fault indicators, to quickly identify fault locations;
- Installing remote-controlled switching devices, including automatic circuit reclosers (**ACRs**), and remote controllable HV switches, to minimise network fault impacts by reducing customer interruptions and quickly restoring supply to the healthy section;
- Implementing pole fire mitigation techniques;
- Proofing the network against animal interference;
- Identifying and replacing or phasing out fault-prone assets; and

Location-specific network performance works are detailed in Jemena's network development plan (see Section 5.1).

[16] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2021-26

[17] AER Regulatory period 2021-2026 will be in financial year

3.5 Quality of Supply

JEN is required to comply with the quality of supply requirements in Section 20 of the EDCoP, and Schedule S5.1a of the NER.

Given a customer can connect anywhere on the network, JEN endeavours to maintain quality of supply levels in line with our requirements at all possible connection points in the network.

Steady-state voltage and voltage variations

Clause 20.4 of the EDCoP specifies the requirements for steady-state voltages, voltage variations (sags and swells) and impulses (transients) at customers' supply points, which is summarised in Table 3-5.

Table 3-5: EDCoP standard nominal voltage variations

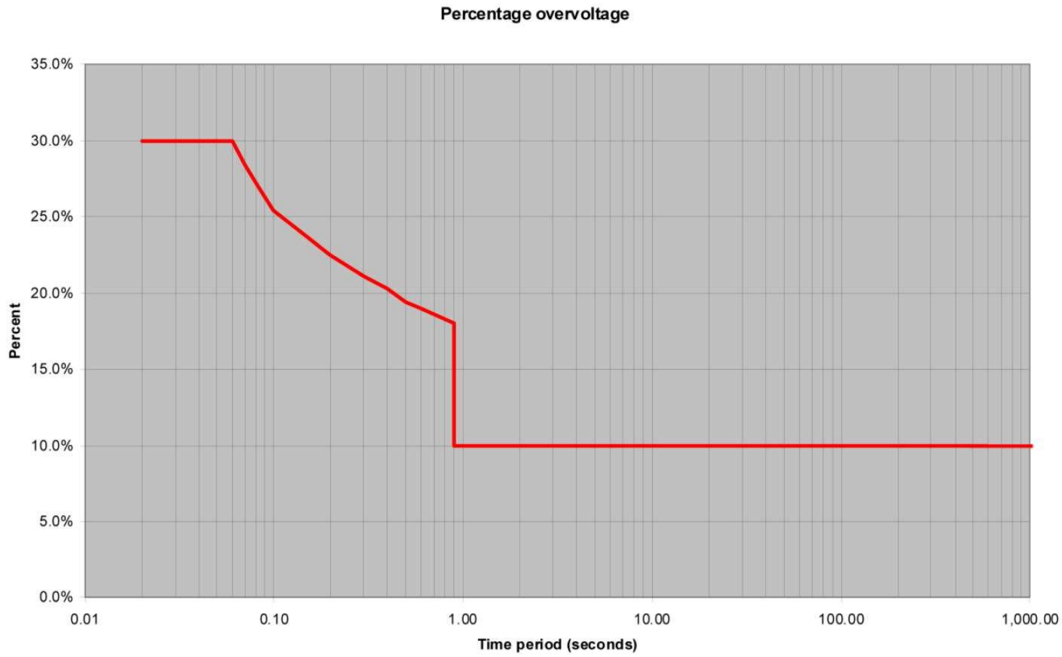
	Voltage	Steady State	Less than 1 minute	Less than 10 seconds		Impulse Voltage
				Ph-E	Ph-Ph	
1	< 1.0 kV	AS 61000.3.100*	+13 % - 10 %	+50% -100%	+20% -100%	6 kV peak
2**		+13 % - 10 %				
3	1 – 6.6 kV	± 6 % (± 10 % Rural Areas)	± 10 %	+80% -100%	+20% -100%	60 kV peak
4	11 kV					95 kV peak
5	22 kV					150 kV peak
6	66 kV	± 10 %	± 15%	+50% -100%	+20% -100%	325 kV peak

Notes:
* When examining network-wide compliance, functional compliance is met if the limits in Table 2 of AS 61000.3.100 (up to 1% of measurements below 216 V and up to 1% of measurements above 253 V) are maintained across at least 95% of a distributor's customers.
** Row 2 values (steady state, less than 1 minute, and less than 10 seconds) define the circumstances in which a distributor must compensate a person whose property is damaged due to voltage variations according to clause 20.4.8. Schedule 3 illustrates this further.

During the period in which a Rapid Earth Fault Current Limiter (**REFCL**) condition is experienced on the distribution system, the Phase to Earth (**Ph-E**) voltage variation in Table 3-5 does not apply. The Phase to Phase voltage variation in Table 3-5 applies to that part of the distribution system experiencing REFCL condition. Refer to Section 5.10 for further information on the impact on JEN and high-voltage customers.

Clause S5.1a.4 of the NER requires a steady state voltage of ±10%, and an overvoltage limit due to a contingency event as described by Figure 323-2, which is an extract of Figure S5.1a.1 in the NER.

Figure 323-2: NER overvoltage limit due to a contingency event



Harmonic voltage distortion

Table 3-6 summarises the requirements for voltage harmonic levels at the customers' supply points (compatibility levels), which are described by Clause S5.1a.6 of the NER and require compliance with AS/NZS 61000.3.6:2012.

Table 3-6: Harmonic levels at customer supply points

	NER		
	THD	Odd harmonics	Even harmonics
Low voltage (≤ 1 kV)	8 %	3rd = 5 % 5th = 6 % 7th = 5 %	2nd = 2 % 4th = 1 % 6th = 0.5 %
Medium / High voltage (> 1 kV)		For higher orders refer to AS/NZS 61000.3.6:2012	

Voltage unbalance (negative sequence voltage)

Table 3-7 summarises the requirements for voltage unbalance, defined by the negative phase sequence voltage, at the customers' supply points, which are described by Schedule 5.1a, clause S5.1a.7 of the NER.

Table 3-7: Voltage unbalance at customer supply points

	NER		
	30 min average	10 min average	1 min average (once per hour)
≤ 10 kV	2.0 %	2.5 %	3.0 %
> 10 kV	1.3 %	2.0 %	2.5 %

Flicker (disturbing load)

Table 3-8 summarises the requirements for voltage flicker at the customers' supply points (compatibility levels), which are described by Schedule 5.1a, Clause S5.1a.5 of the NER and require compliance with AS/NZS 61000.3.7:2001.

Table 3-8: Flicker at customer supply points

Voltage	P_{ST}	P_{LT}
≤ 1 kV	1.0	0.8
1 – 22 kV	1.0	0.8
66 kV	0.8[18]	0.6[19]

3.5.1 Power quality monitoring coverage

Every JEN zone substation has at least one power quality monitoring device permanently installed on site. A power quality monitoring device is also installed at the far end of one high voltage distribution feeder emanating from each zone substation, usually the longest feeder.

On the LV network, the completed rollout of AMI meters has allowed basic power quality monitoring of the customer connection points in the LV distribution system. Since mid-2018, JEN has acquired voltage and current data in a time series format (5-minute snapshots) and has established a data analytics platform and algorithms to facilitate proactive quality of supply monitoring and rectification. Note that while the AMI meters have provided JEN with insight of power quality performance at various parts of its LV distribution network, the accuracy of AMI meters does not meet the requirement for compliance purposes.

JEN participates in the Power Quality Compliance Audit (**PQCA**) conducted annually by the University of Wollongong. In this year's PQCA, JEN has included 1,928 3-phase smart meter sites in addition to the end-of-feeder power quality monitors. Due to the high volume of LV sites, survey results in this DAPR are shown for the 'worst 50' sites only.

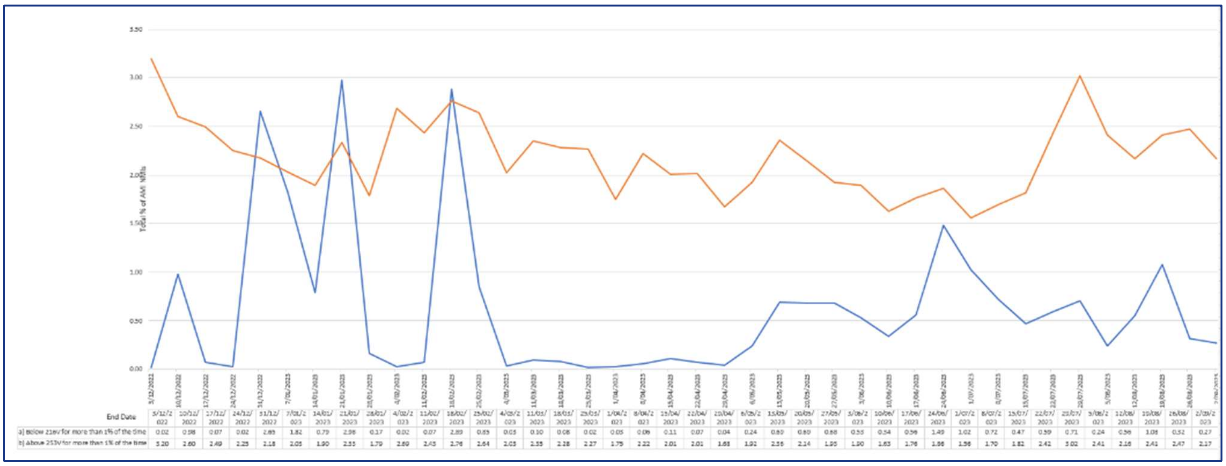
3.5.2 LV power quality performance

The data obtained from AMI meters on JEN's network indicate that there are customers who are experiencing steady-state voltages outside of EDCoP limits some of the time. Over-voltage events are at least in part due to the increased penetration of residential solar PV systems connected to the network, whereas low-voltage events are driven by the increased proliferation of air conditioning units. JEN has been investigating and implementing solutions and has been successful in proactively bringing the voltage back into compliance. Figure 3-3 demonstrates V1 and V99 compliance is met for the limits in Table 2 Clause 20.4 of the EDCoP (up to 1% of measurements below 216 V and up to 1% of measurements above 253 V are maintained across at least 95% of a distributor's customers).

[18] Planning levels, not compatibility levels.

[19] Planning levels, not compatibility levels.

Figure 3-3: LV Network V1 and V99 compliance



3.5.3 MV power quality performance

This survey analyses steady-state voltages, voltage unbalance, voltage harmonics, voltage sags and swells, and flicker. To date, JEN has provided power quality data from the medium-voltage (**MV**) power quality monitors located at the zone substations and end of feeders. The results of the latest financial year survey are summarised below.

Steady-state voltage performance

The MV steady state voltage performance of each 22 kV and 11 kV zone substation over the 2021-22 financial year is summarised in Figure 3-4. The performance of each 6.6 kV zone substation is summarised in Figure 3-5 and the summary of the worst 50 LV sites is summarised in Figure 3-6.

The results show all 6.6 kV, 11 kV and 22 kV zone substations are compliant. For the worst 50 LV sites (out of a total of nearly 2,000 sites surveyed), there are both high and low-voltage instances. JEN is implementing proactive measures to bring these sites back into compliance.

Figure 3-4: Steady-state voltage performance – 22 kV and 11 kV sites

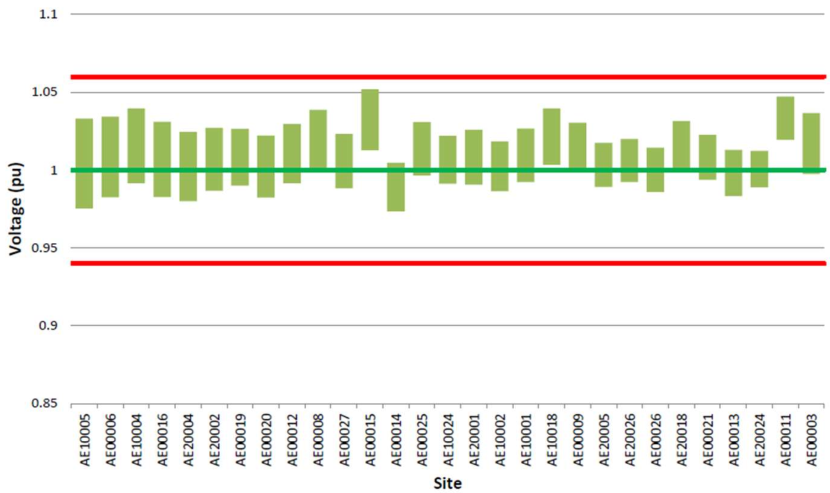


Figure 3-5: Steady-state voltage performance – 6.6 kV sites

Figure 3-6: Steady-state voltage performance – LV sites (worst 50)

Voltage sag and swell performance

Voltage sags and swells are recorded by the permanent power quality meters installed at the zone substations only. While swell is not a common occurrence, the sag performance of each zone substation over the 2022/23 financial year is summarised in Figure 3-7 and

Figure **3-8**. All sites are within the limits applied by the PQCA analysis.

Figure 3-7: Voltage sag performance – 22 kV and 11 kV sites

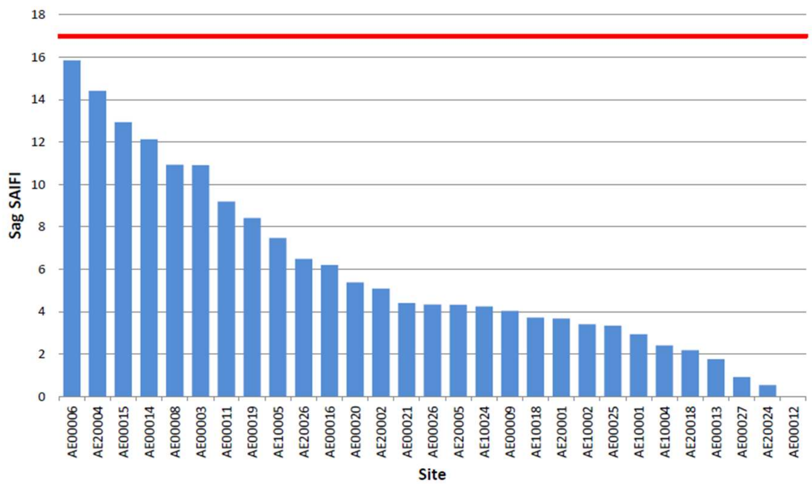


Figure 3-8: Voltage sag performance – 6.6 kV site

Harmonic performance

Harmonics are recorded by the permanent power quality meters installed at the zone substations only. Results for each 22 kV and 11 kV zone substation for the 2022/23 financial year are presented in Figure 3-9. Results for each 6.6 kV zone substation are presented in Figure 3-10. These results show that the total harmonic distortion (**THD**) is below the 8% NER limit at all the zone substations.

Figure 3-9: Harmonic distortion levels – 22 kV and 11 kV sites

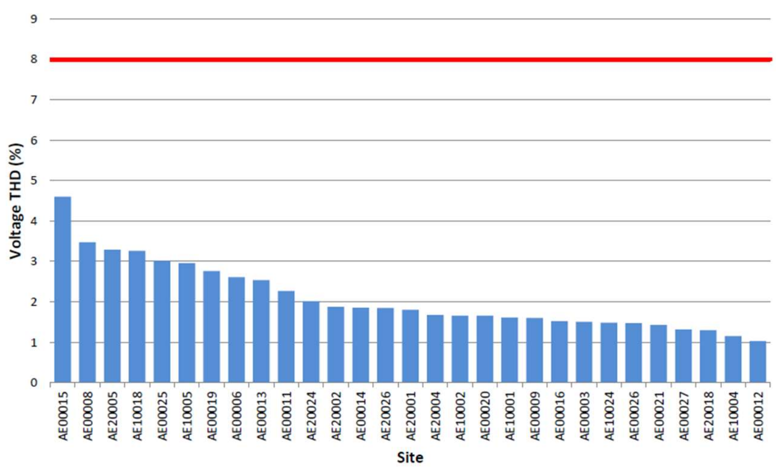
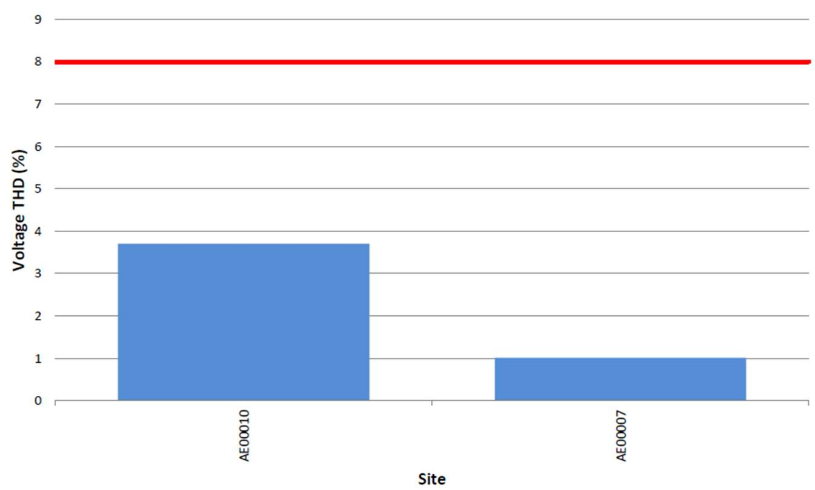


Figure 3-10: Harmonic distortion levels – 6.6 kV sites



Voltage unbalance performance

Voltage unbalance is recorded by permanent power quality meters installed at JEN's zone substations and can be calculated for 3-phase smart meter LV sites.

Results for each 22 kV and 11 kV zone substation for the 2022-23 financial year are presented in Figure 3-11, for each 6.6 kV zone substation are presented in Figure 3-12, and for the worst 50 LV sites are presented in Figure 3-13

Results shown in Figure 3-11 and Figure 3-12 indicate that Jemena is compliant at the MV sites where voltage unbalance is monitored.

Note that the voltage unbalance data for the smart meter LV sites are calculated using the voltage magnitudes recorded for each phase of the 3-phase smart meters and are indicative as the measurements are not carried out as per the NER requirement.

Figure 3-11: Voltage unbalance (negative sequence voltage) – 22 kV and 11 kV sites

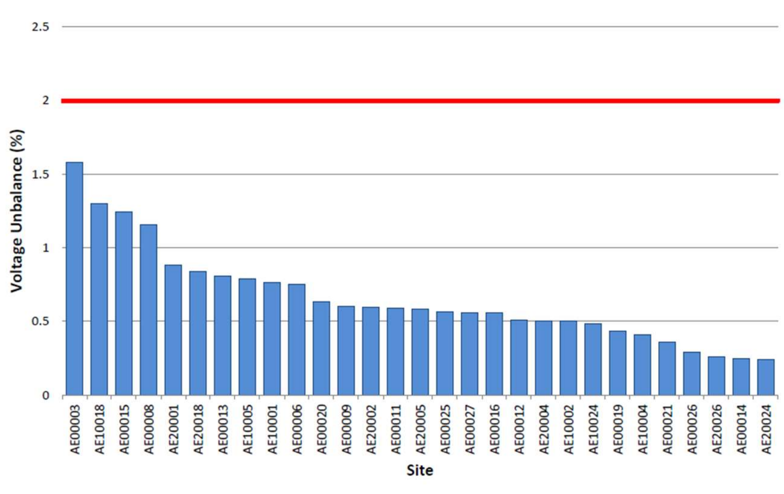


Figure 3-12: Voltage unbalance (negative sequence voltage) – 6.6 kV sites

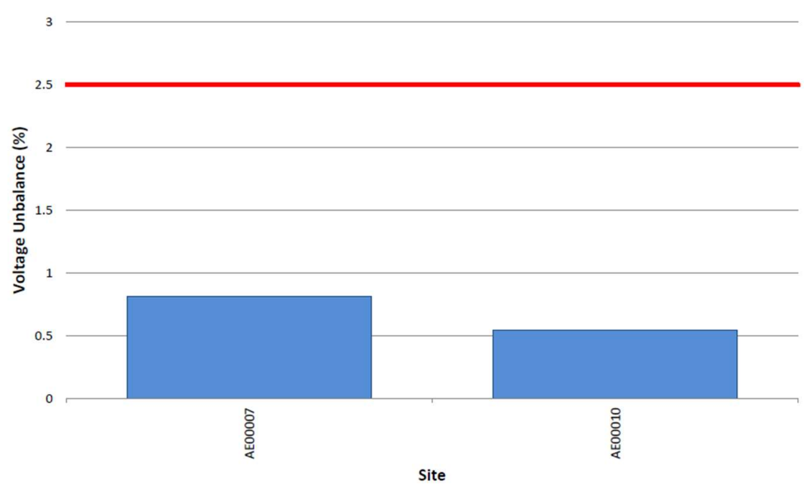
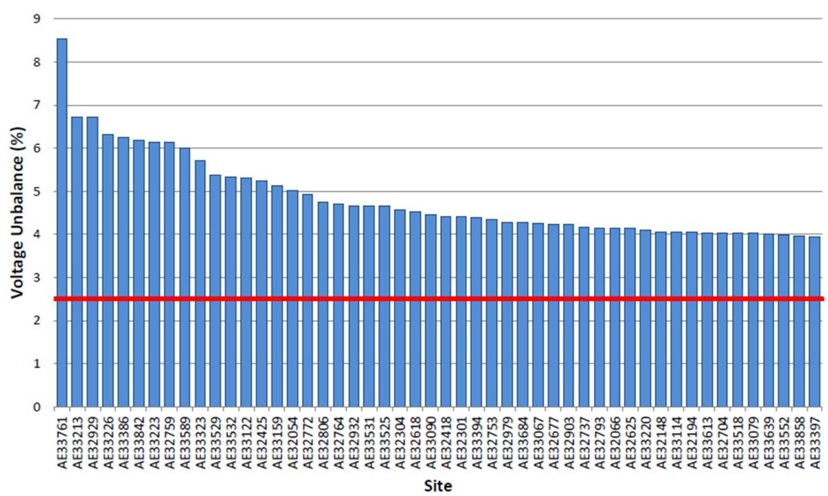


Figure 3-13: Voltage unbalance (negative sequence voltage) – LV sites (worst 50)



Flicker performance

Although flicker cannot be directly measured due to measurement limitations of JEN's power quality meters, the University of Wollongong has calculated flicker levels using the raw data recorded by the meters.

Short-term and long-term flicker measurement results for the 2022-23 financial year, presented in Figure 3-14, Figure 3-15, Figure 3-16 and Figure 3-17 indicate that JEN is compliant at the MV sites where flicker is monitored.

Figure 3-14: 11 kV and 22 kV Voltage flicker levels – Pst distribution

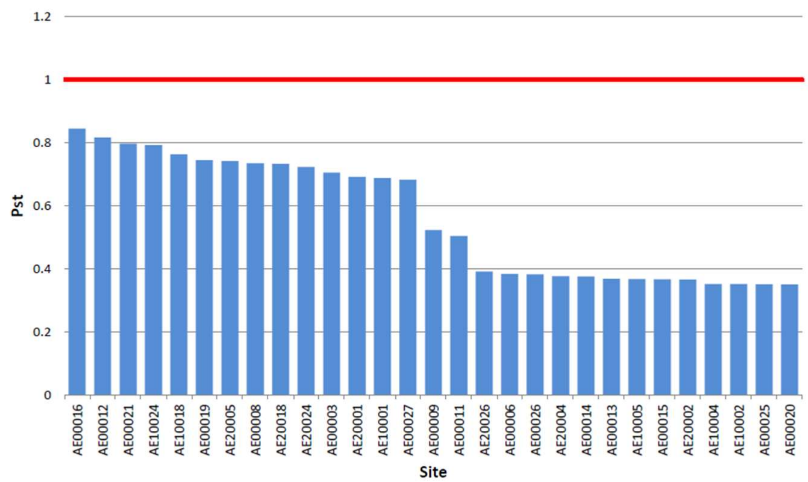


Figure 3-15: 11 kV and 22 kV Voltage flicker levels – Plt distribution

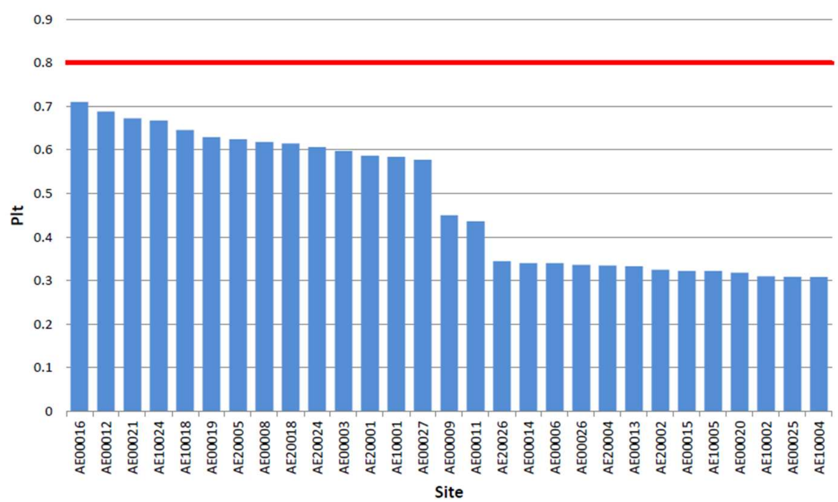


Figure 3-16: 6.6 kV Voltage flicker levels – Pst distribution

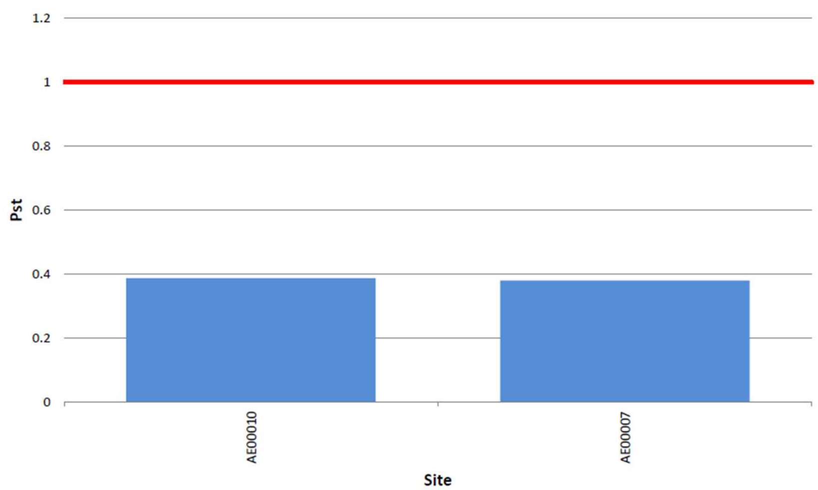
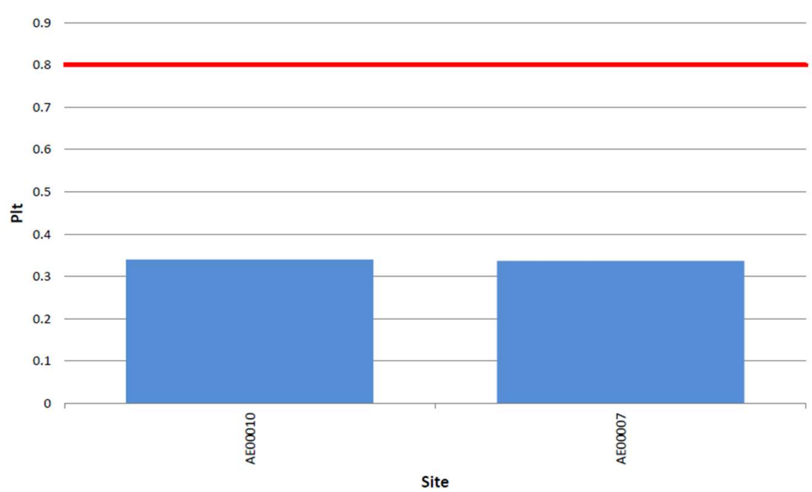


Figure 3-17: 6.6 kV Voltage flicker levels – Plt distribution



3.5.4 Power quality corrective actions

When JEN becomes aware of an LV voltage issue at a customer's point of connection, primarily through customer complaint, an investigation is launched in which portable power quality monitoring devices are installed at the site for seven days to check for compliance with the EDCoP. If the results obtained from these devices confirm that there is a network problem, JEN will undertake one of the following corrective actions:

- Distribution transformer off-load tap change;

- Upgrading distribution substation;
- Load balancing across the three phases of the LV circuits;
- Re-conductoring of LV circuits; or
- Review zone substation voltage set points, which may include applying line drop compensation or float voltage for dynamic voltage management.

With the availability of five-minute snapshots of power quality data and the establishment of an advanced data analytics platform, JEN now conducts a desktop assessment before deciding the need to install a portable power quality monitoring device.

Proactive management of power quality issues in the LV network, using AMI monitoring, is progressively implemented.

On the MV network, with power quality in 2022-2023 generally within regulatory requirements, JEN's power quality corrective action primarily focuses on monitoring and maintaining existing power quality levels.

There are no specific works in the forward planning period to address harmonic distortion, voltage unbalance, or voltage flicker detailed in Jemena's network development plans.

3.5.5 Power quality initiatives

JEN is currently working on the following power quality initiatives to address voltage control challenges within the low voltage (LV) network.

Volt-VAr Control (VVC) Program

Voltage disturbances occurring on the LV network due to increased penetration of residential and commercial solar photovoltaic (solar PV) generation and the emergence of new DER technologies (such as battery storage, electric vehicles, and peer-to-peer energy trading), mean that the existing automatic voltage regulation scheme deployed on the high and medium voltage network may not be adequate to ensure the mandated quality of supply to LV customers.

JEN is currently establishing a Volt-VAr Control (**VVC**) program over the next five years for strategically responding to the challenges and opportunities associated with the changing energy landscape. The VVC program is part of a strategic roadmap of initiatives to provide near real-time network voltage and reactive power flow optimisation control functionality, which integrates network voltage and reactive power resources (and DER) with advanced centralised applications supported by JEN's Advanced Distribution Management System (**ADMS**).

The VVC program:

- seeks to improve voltage compliance performance for JEN's customers across the network to enable customer DER, then maintain this performance in an environment of increasing DER penetration;
- involves identifying and implementing VVC capabilities required to address the identified needs of the network on a least-regrets basis;
- seeks to open up new and additional revenue opportunities that support expenditure on VVC capabilities;
- optimises the sequence of VVC capability investment to provide the highest net benefit, considering risk, performance, cost, timing and uncertainty;
- complements and supports other Future Network initiatives and programs;
- is scalable for the future; and
- ensures the total lifecycle costs of the risk and investment are minimised for customers and the business.

Smart PV inverter

As voltage issues on the LV network are contributed to in part by increasing penetration of rooftop PV systems, one possible solution is to modify the local PV generation in response to network voltage conditions by utilising functions in smart PV inverters. In coordination with other Victorian electricity DNSPs, JEN has mandated power quality response modes on the inverters of new solar installations since December 2019.

Supply monitoring project

Since the beginning of 2017, Jemena has been implementing a ‘supply monitoring’ project, which involves collecting time-synchronised data (voltage, current and power factor) from every AMI meter at five-minute intervals and developing advanced analytic applications on the data. In 2017, the software system for the acquisition of five-minute data was commissioned, and since July 2018, JEN has achieved the collection of five-minute data from over 95% of the AMI meters. A hardware platform for running advanced data analytics has been installed and several data analytics algorithms have been developed, including:

- **Supply neutral integrity monitoring** – provides round-the-clock monitoring of the integrity of the service wire/cable that connects to customer premises. High impedance connection on the service line/cable presents a health and safety hazard to the customers and could develop into a widespread supply outage if the condition is not detected and rectified in time. This functionality has been successfully tested and rolled out across the whole network. The detection and rectification work to address broken/high-resistance neutrals is ongoing as part of our business-as-usual process.
- **Customer phase connection identification** – identify the phase connection of low voltage customers based on voltage correlation studies. Correct phase identification allows Jemena to develop an accurate LV network model that can be used to balance loads/generations between phases, improve asset utilisation and improve the quality of supply to its customers. A phase identification algorithm is being run on the 5-minute data collected since July 2018.
- **Proactive quality of supply monitoring** – the time-series voltage data collected is used to assist with voltage complaint investigations and general improvement to voltage delivery.

While JEN has achieved good results from the data analytics algorithms so far, more work is required to further improve the accuracy, including site measurement verifications. Continued development of the analytics software and hardware platform is required to handle the increasing demand posed by the voluminous data collection.

LV network modelling

An LV network model is set up in JEN analytics to provide modelling of power parameters in different parts of the LV network. Analytics results are also used to improve the accuracy of the LV network data that reside in JEN’s Geospatial Information System (**GIS**). JEN is working on a simulation facility that allows the effect of new DER to be modelled before it is connected to the network.

4. Network Demand Forecasts

This section presents:

- JEN's network-wide historical actual maximum and minimum demand;
- A comparison of the 2023 summer maximum and minimum demand forecasts with the forecasts published in the 2022 DAPR;
- A review of the accuracy of terminal station and zone substation maximum and minimum demand forecasts for 2023 against observed maximum demand;
- A review of penetration levels of both residential and commercial rooftop solar PV on JEN's network; and
- Current utilisation statistics for JEN's zone substations and HV feeders.

Demand and energy forecasts for Jemena's connection points can be found in the 2023 TCPR, which is available on JEN's website[20].

[20] http://jemena.com.au/industry/electricity/network-planning

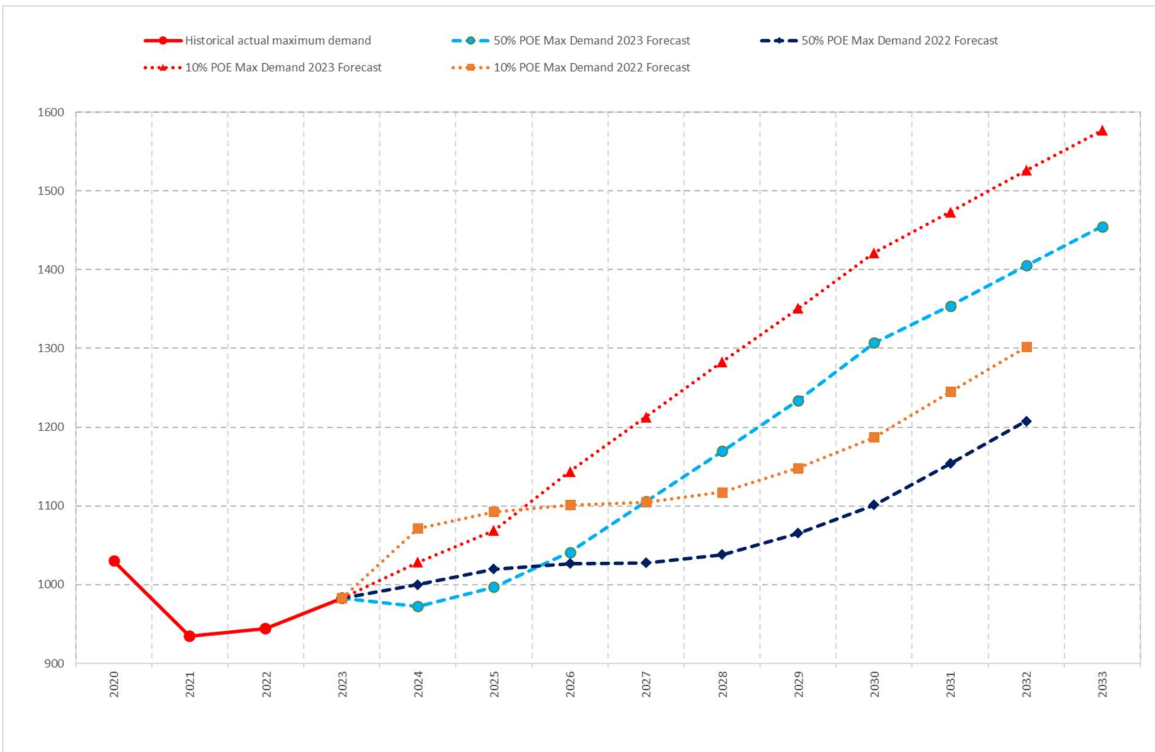
4.1 Changes to Demand Forecasts

Maximum demand

Error! Reference source not found. shows the historical summer maximum demand on Jemena's electricity network since 2020 and a comparison of the 2022 Blunomy to current (2023) Blunomy system-level (top-down) maximum demand forecasts for the JEN region over the 2023-24 to 2032-33 outlook period.

At the system level, the underlying maximum demand forecasts over the forward five-year planning period for the JEN region are slightly lower in the next 3 years (up to 2025) compared with the 2022 forecast, due in part to the change in top-down methodology as well as an overall milder summer experienced within Victoria. The new top-down forecast includes a significant portion of forecast EV load, solar PV and gas electrification impact to be integrated in later years of the forecast (from 2026 onwards). Within the forward five-year planning period, JEN considers this change to the system-level demand forecast to have an impact on its spatial-level forecasts, changing the peak maximum demand from summer to winter in the later years.

Figure 4-1: Jemena network maximum demand forecast comparison

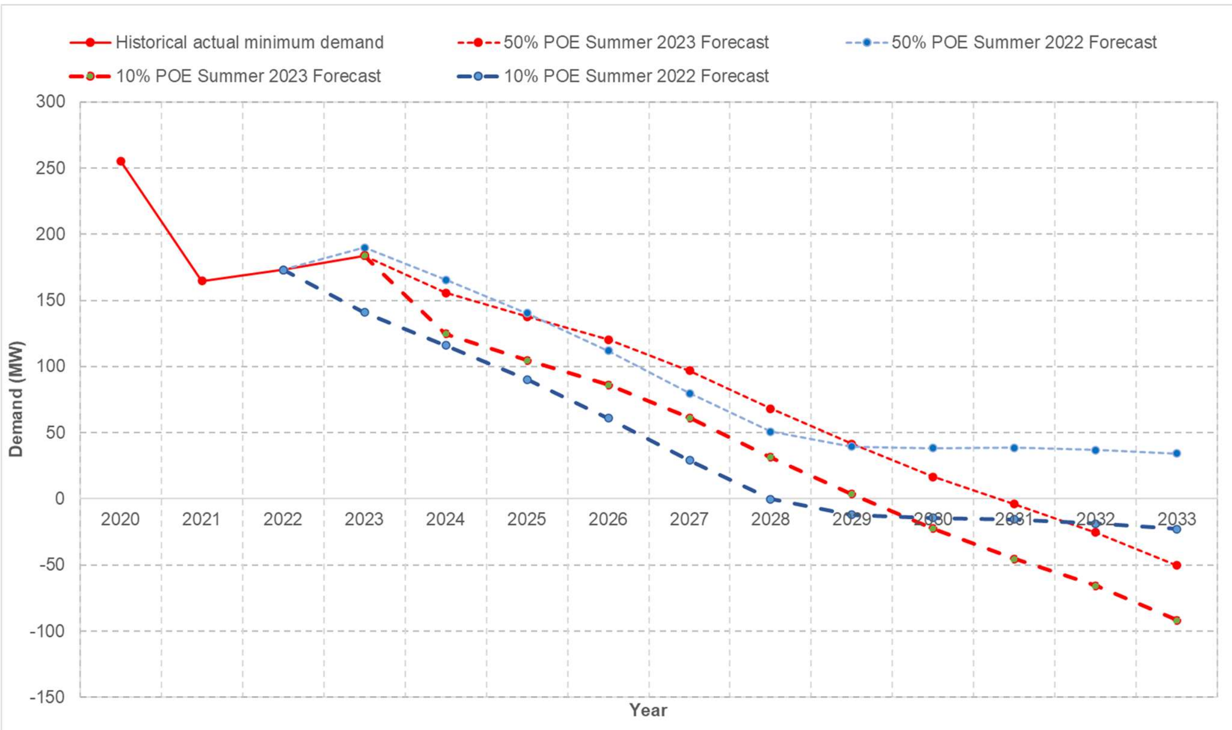


Minimum demand

Figure 4-2 shows the historical summer minimum demand on Jemena's electricity network since 2020 and a comparison of the 2022 Blunomy to current (2023) Blunomy system-level (top-down) minimum demand forecasts for the JEN region over the 2023-24 to 2032-33 outlook period.

At the system level, the underlying minimum demand forecasts over the forward five-year planning period for the JEN region are slightly higher in the next 5 years (up to 2028) compared with the 2022 forecast, due to the changes to different driver uptake forecasts such as EV, electrification of gas and solar PV. Within the forward five-year planning period, JEN considers this change to the system-level minimum demand forecast to be immaterial.

Figure 4-2: Jemena network minimum demand forecast comparison



4.2 Forecast Demand

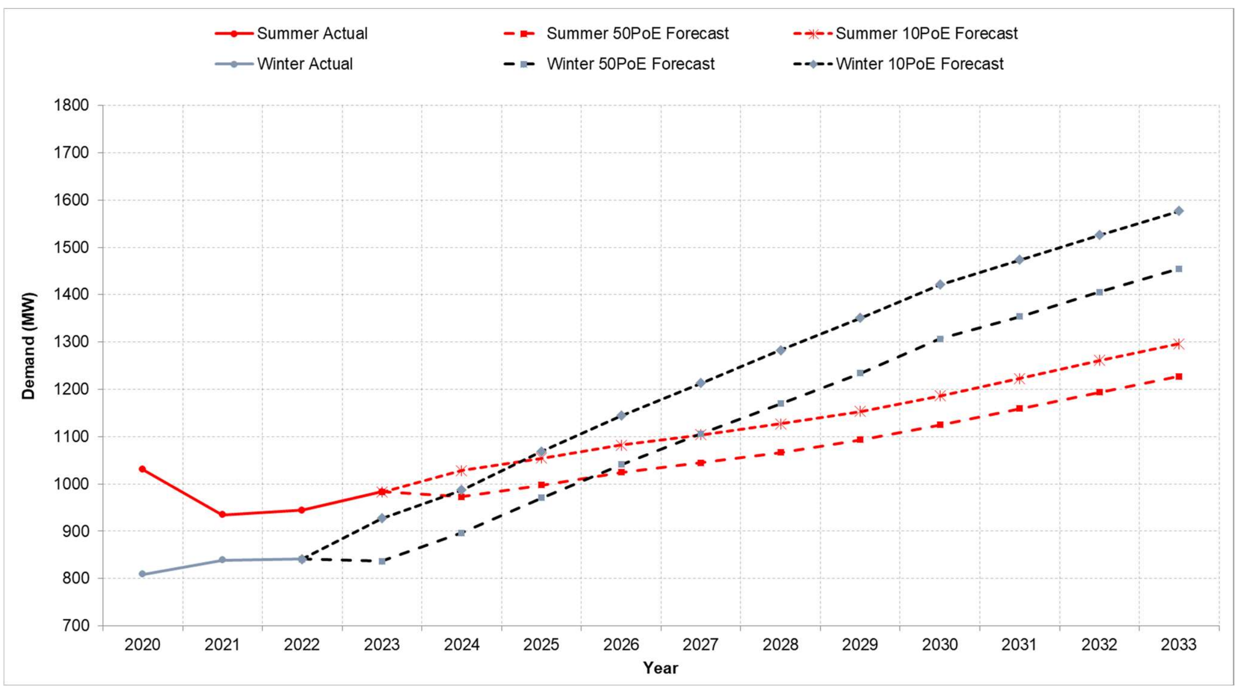
Maximum demand

As a whole, the demand growth across JEN's network is progressively increasing, with the total underlying (excluding large customer load forecast) network 50% POE maximum demand forecast to grow at an average rate of 3.54% per annum over the next five years (2023-24 to 2028-29). This is being driven in part by the reopening of businesses after the pandemic, a projected return to trend GSP, and the impact of gas and transport electrification. Table 4-1 presents the historical observed actual and ten-year maximum demand forecasts for both 10% POE and 50% POE conditions (i.e. all JEN network customers coincident net demand aggregated at the system level). The forecasts are also presented in Figure 4-3 along with the historical actual demand since 2022.

Table 4-1: Jemena network maximum demand forecast

Demand (MW)	Actual	Forecast										Average annual growth	
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2023-2028	2023-2033
Summer (50PoE)	944	983	973	997	1024	1045	1067	1094	1125	1159	1194	1227	1.64%	2.24%
Winter (50PoE)	841	837	897	971	1041	1106	1170	1234	1307	1354	1405	1455	6.93%	5.69%
Summer (10PoE)	944	983	1028	1054	1082	1104	1127	1154	1186	1223	1261	1297	2.76%	2.81%
Winter (10PoE)	944	983	1028	1054	1082	1104	1127	1154	1186	1223	1261	1297	2.76%	2.81%
Max Demand (50POE)	944	983	973	997	1041	1106	1170	1234	1307	1354	1405	1455	3.54%	4.00%
Max Demand (10POE)	944	983	1028	1069	1144	1213	1283	1351	1421	1473	1526	1577	5.47%	4.84%

Figure 4-3: Jemena network historical and forecast maximum demand



Despite the general growth in demand at the network level, there are areas within the network where maximum demand is forecast to grow well beyond the network average level, while other parts of the network are forecast to experience a decline in maximum demand as a result of manufacturing closures.

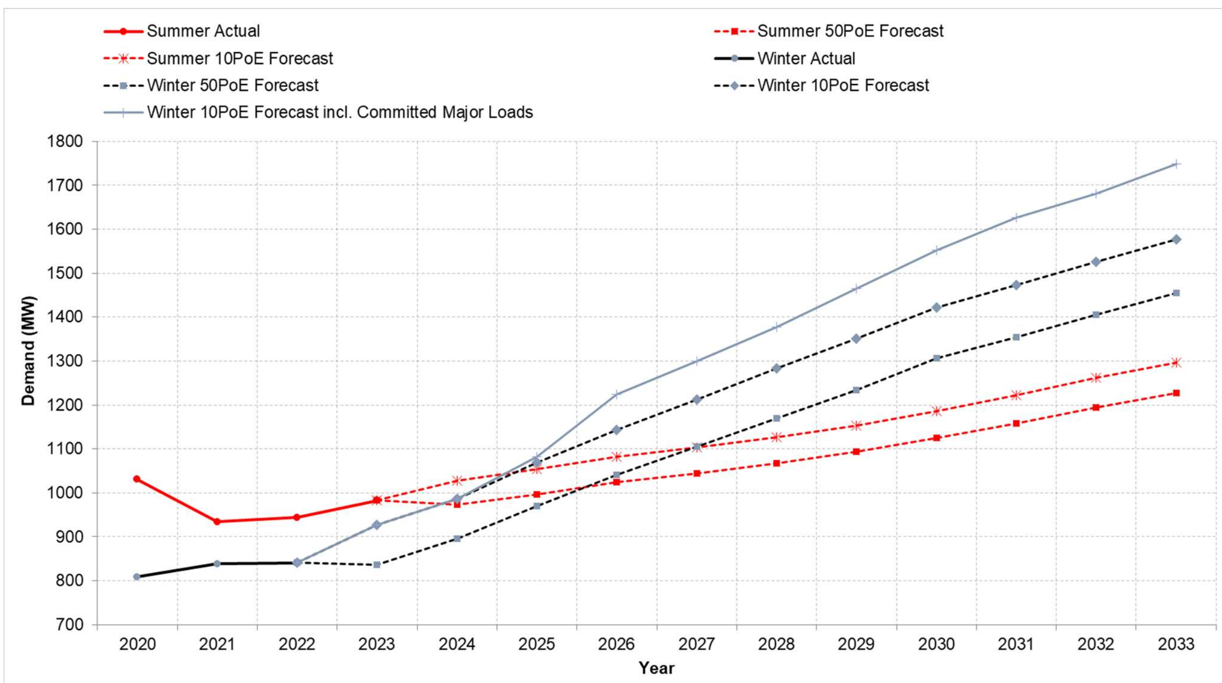
In general, JEN expects strong growth in the northern half of the network. This is largely due to new developments associated with urban sprawl towards the edge of the Urban Growth Boundary. As a result of this urban sprawl and the extension of the Urban Growth Boundary, JEN expects to see continued strong growth in the areas currently supplied by the Kalkallo (maximum demand forecast to grow at 12.2% per annum over the next five years), Sydenham (3.99% p.a.), Somerton (4.80% p.a.) and Coolaroo (4.37% p.a.) zone substations.

Some pockets within established inner suburbs are also experiencing strong growth as a result of amendments to the planning schemes for high-density living. The high growth is predominately driven by the development of high-rise residential and office buildings, and the expansion of community facilities and services, such as around Footscray Central Activities Area, Fairfield and Essendon Airport. As a result, JEN is forecasting relatively high growth in maximum demand for areas currently supplied by Flemington (8.79% p.a.), Yarraville (3.46% p.a.), Fairfield (8.00% p.a.), Footscray East (3.77% p.a.), Footscray West (6.49% p.a.), Coburg North (4.34% p.a.), Coburg South (1.79% p.a.), North Essendon (2.88% p.a.), and Newport (1.80% p.a.) zone substations.

JEN is also experiencing a high volume of large customer load connections. However, this forecast is separated from JEN's underlying maximum demand forecast presented in Table 4-1. This large customer connection forecast is separated to maintain JEN's underlying maximum demand forecast and therefore it does not impact the spatial level forecast, given these large customer connections are mostly connected to the subtransmission network level.

Based on large customer connections (committed projects only), Figure 4-4 presents the total system level forecast with JEN underlying forecast and large customer connection forecast. It should be noted that if JEN were to include the non-committed projects, the forecast demand would be significantly higher than the information presented in Figure 4-4.

Figure 4-4: Forecast maximum demand with committed large customer connections



Other parts of the network, generally in the south, are expecting low growth or a decline in maximum demand over the forward planning period

Table 4-2 presents a summary of the expected growth/decline in maximum demand across JEN over the next five years for both summer and winter.

Table 4-2: Supply area average annual growth over the next five years (2023-24 to 2028-28)

Season	Supply area average annual growth (2022-23 to 2027-28)			
	Strong growth (>5% p.a.)	High growth (3-5% p.a.)	Medium growth (1-3 % p.a.)	Low growth and possible decline (<1% p.a.)
Summer	Fairfield, Footscray West, Kalkallo	Coburg North, Flemington, Sunbury, Sydenham, and Somerton	Broadmeadows, Braybrook, Coburg South, Coolaroo, East Preston (EP), Footscray East, North Heidelberg North Essendon, Newport, Tullamarine, Tottenham, and Yarraville	Airport West, Preston, Broadmeadows South, Essendon, Heidelberg, Pascoe Vale
Winter	Fairfield, Flemington, Kalkallo, Sunbury, and Sydenham	Braybrook, Coburg North, Coburg South, Coolaroo, East Preston (EPN), Footscray East, Footscray West, Heidelberg, North Heidelberg, North Essendon, Pascoe Vale, Somerton, Tottenham, and Yaraville	Airport West, Broadmeadows, Broadmeadows South, Essendon, Newport, Preston, St. Albans, Tullamarine, and Watsonia	Thomastown

Minimum demand

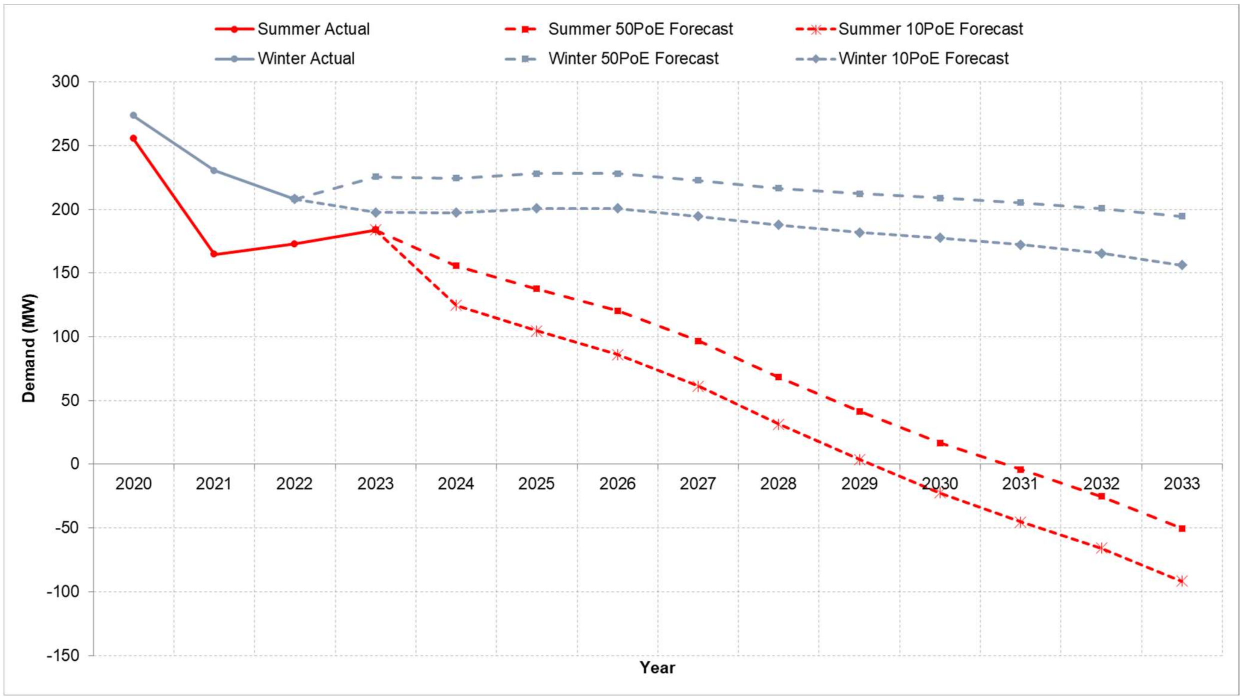
The minimum demand across JEN is expected to continue to decline rapidly due to the continued uptake of embedded generation (in particular, solar PV systems) at an average rate of -22 MW per annum under 50% POE conditions over the next five years (2023-24 to 2027-28).

Table 4-3 presents the historical observed actual and ten-year minimum demand forecasts for both 10% POE and 50% POE conditions. The forecasts are also presented in Figure 4-5 showing the historical annual observed minimum demand and ten-year forecasts for 10% POE and 50% POE conditions.

Table 4-3: Jemena network minimum demand forecast

Demand (MW)	Actual	Forecast											Average annual growth	
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2023-2028	2023-2033
Summer (50PoE)	173.0	183.9	155.8	137.6	120.4	96.9	68.2	41.4	16.7	-4.0	-25.3	-50.4	-21.9	-22.9
Winter (50PoE)	208.1	225.5	224.6	228.1	228.2	222.8	216.6	212.3	208.9	205.3	200.8	194.7	-2.0	-3.3
Summer (10PoE)	173.0	183.9	124.6	104.6	86.1	61.3	31.4	3.6	-22.5	-45.3	-65.7	-91.8	-23.3	-24.0
Winter (10PoE)	208.1	197.7	197.4	200.8	200.7	194.6	187.7	181.8	177.7	172.3	165.5	156.3	-2.4	-4.6
Minimum Demand (50POE)	173.0	183.9	155.8	137.6	120.4	96.9	68.2	41.4	16.7	-4.0	-25.3	-50.4	-21.9	-22.9
Minimum Demand (10POE)	173.0	183.9	124.6	104.6	86.1	61.3	31.4	3.6	-22.5	-45.3	-65.7	-91.8	-23.3	-24.0

Figure 4-5: Jemena's historical and total minimum demand forecast



Despite the strong decline in minimum demand at the network level, there are areas within the network where minimum demand is forecast to decline even well beyond the network average level, to the point where minimum demand may go negative, while other parts of the network are forecast to experience a slower decline.

In general, JEN expects a strong decline in minimum demand (or strong growth in embedded generation) in the northern half of the network. This is largely driven by 7-star building code new developments associated with urban sprawl towards the edge of the Urban Growth Boundary where solar PV installation is expected to be demanded as part of the new development. As a result of this urban sprawl and the extension of the Urban Growth Boundary, JEN expects to see a continued strong decline in minimum demand in the areas currently supplied by the Coolaroo and Kalkallo zone substations. Table 4-4 presents a summary of the expected decline in minimum demand across JEN over the next five years.

Table 4-4: Supply area average annual minimum demand decline rate (2023-24 to 2027-28)

Season	Supply area average annual decline rate (2023-24 to 2027-28)			
	Strong decline (less than minus 3 MVA pa)	High decline (minus 2-3 MVA pa)	Medium decline (minus 1-2 MVA pa)	Low decline and possible growth (greater than minus 1 MVA pa)
Annual under 50% POE	Coolaroo, Kalkallo	Airport West, Broadmeadows, North Heidelberg, Sunbury, Sydenham, Somerton	Coburg South, Heidelberg, Preston, Pascoe Vale	Braybrook, Broadmeadows South, Coburg North, Essendon, Fairfield, Flemington, Footscray East, Footscray West, North Essendon, Newport, East Preston, Tullamarine, St. Albans, Thomastown, Tottenham, Watsonia and Yarraville
Annual under 10% POE	Coolaroo,	Airport West, Kalkallo, North Heidelberg, Sunbury, Sydenham, Somerton	Coburg South, Broadmeadows, Essendon, Footscray West, Heidelberg, Preston, Pascoe Value	Braybrook, Broadmeadows South, Coburg North, Fairfield, Flemington, Footscray East, North Essendon, Newport, East Preston, Tullamarine, St. Albans, Thomastown, Tottenham, Watsonia and Yarraville

4.3 Review of 2022 Demand Forecasts

As part of its best practice distribution load forecasting, JEN reviews its forecast demand against the observed demand and seeks to understand the cause of any discrepancies.

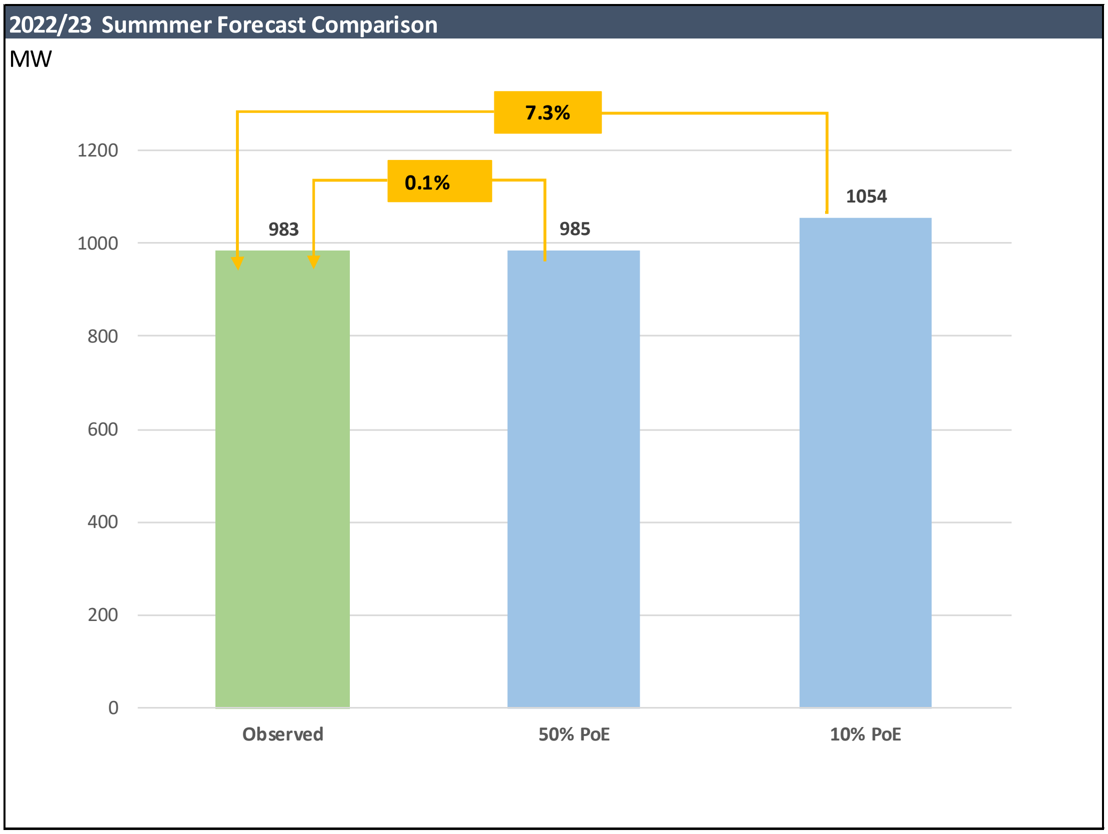
The observed 2023 summer and 2022 winter demands generally agree favourably with JEN's forecasts that were published in the 2022 DAPR.

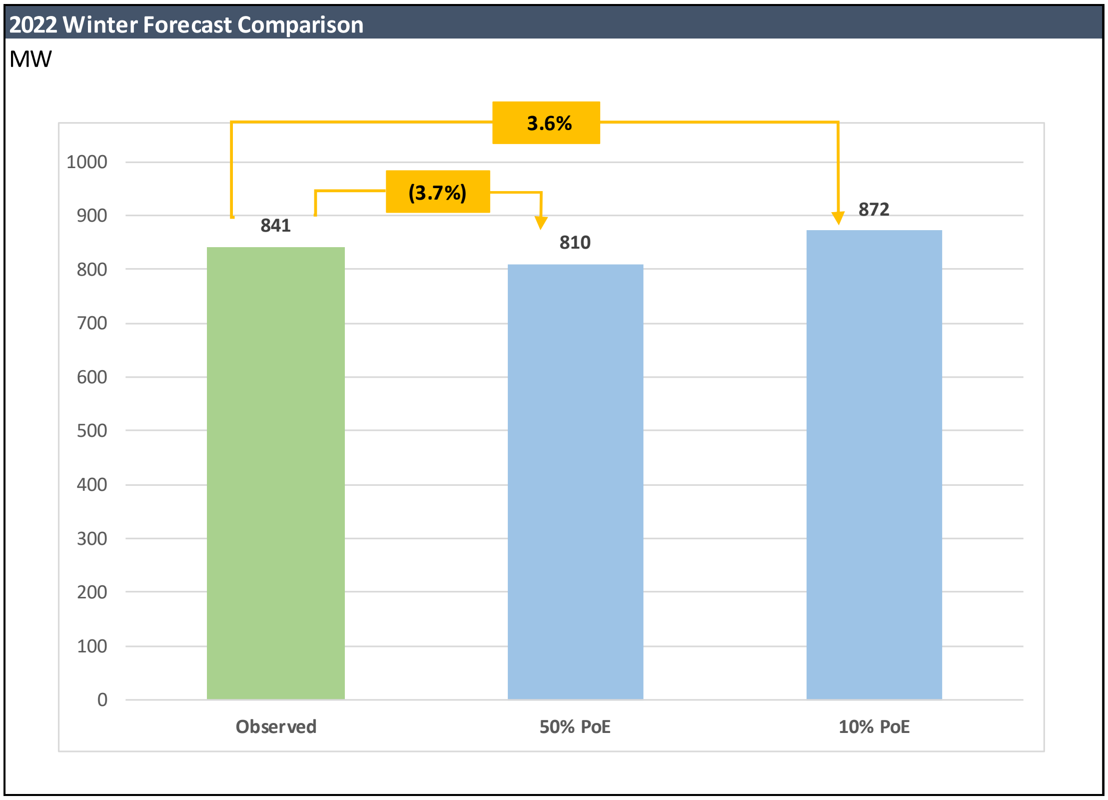
4.3.1 Network forecast

Maximum demand

The observed network level maximum demand on the Jemena network was in line with JEN's 50% POE and 10% POE forecasts. Maximum demand was 983 MW observed on 17 January 2023 at 5.45 pm. The average temperature on this day was 27.9°Celsius. The winter maximum demand was 841 MW observed on 21 July 2022 at 8.20 pm. JEN's summer demand was 0.1% below the forecast 50% POE and the winter demand was 3.7% above the 50% POE forecast as shown in Figure 4-6.

Figure 4-6: JEN Observed Maximum Demand 2021/22





Contribution of Solar PV during summer maximum demand

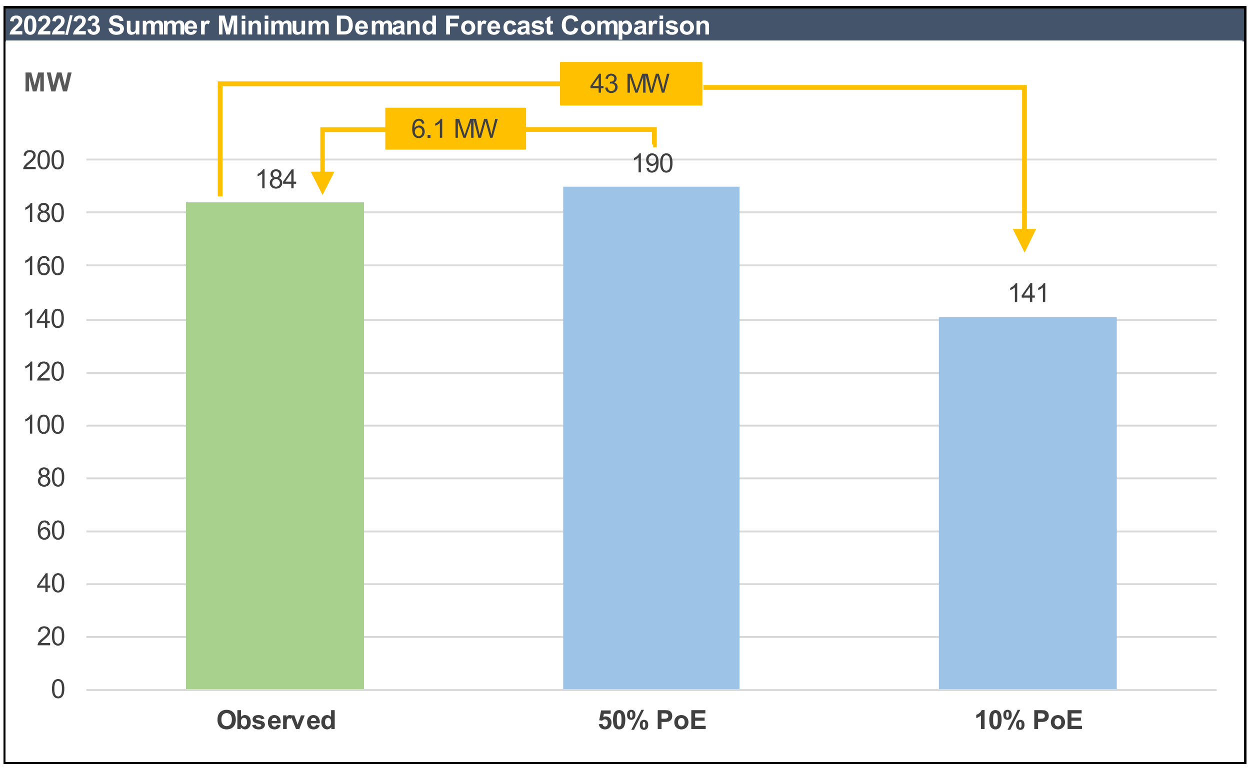
The summer maximum demand on JEN's network was observed at 5.45 pm on 17 January 2023. Of the approximately 322 MW of nameplate installed PV systems in the network (as of January 2023), the amount of solar PV export contribution at the time of network maximum demand was about 140 MW.

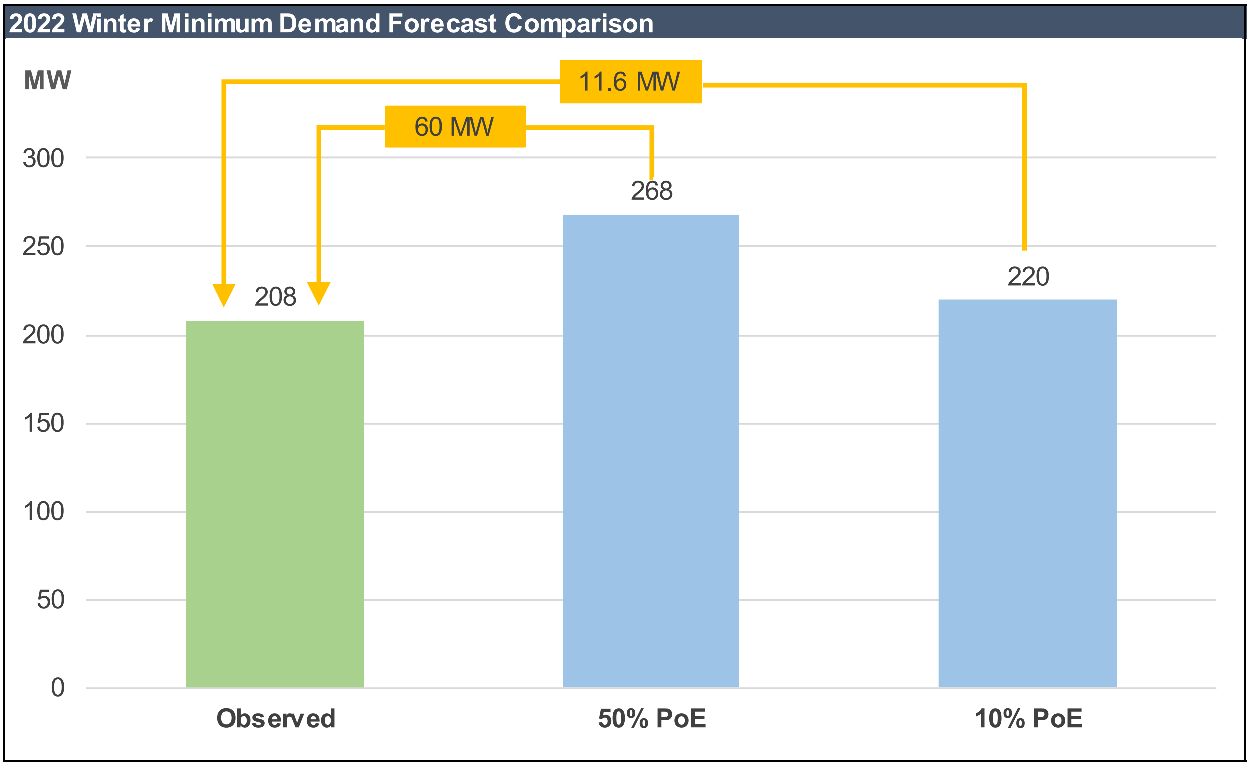
Minimum demand

The observed network level minimum demand on the Jemena network was in line with JEN's 50% POE and 10% POE forecasts. Minimum demand was 184 MW observed on 18 December 2022 at 13:30. The winter minimum demand was 208 MW observed on 25 September 2022 at 12:00. JEN's summer minimum demand was 6.1MW below the forecast 50% POE and the winter demand was 60MW below the 50% POE forecast as shown in

Figure 4-7.

Figure 4-7: JEN Observed Minimum Demand 2021/22





4.3.2 Terminal station forecast

Maximum demand

The observed terminal station maximum demand was within 10% of the 50% POE terminal station forecast for all terminal stations except Brooklyn 22 kV (BLTS22) and Brunswick (BTS). This was mainly caused by a changing HV customer load profile over the last year at BLTS 22 and the higher growth rate than expected at BTS. However, the total non-coincidental maximum demand of all terminal stations was within 1.88% of the 50% POE forecast.

Table 4-5: Comparison of terminal station observed maximum demand to JEN's 2022 forecast

Terminal Station	50% POE (MW)	10% POE (MW)	Actual MD (MW)	Temp. Adjusted MD (MW)	% Difference (compared to 50% POE)
BLTS66	124.27	132.51	120.96	124.50	-0.18%
BLTS22	3.03	3.03	3.74	3.74	-19.00%
BTS	53.01	58.29	58.32	59.12	-10.34%
KTS B1-B2	227.83	245.87	222.46	224.77	1.36%
KTS B3-B4	85.13	94.47	82.94	87.78	-3.02%
SMTS	87.96	92.06	90.57	92.38	-4.78%
TSTS	26.34	28.61	25.98	26.31	0.12%
TTS B1-B2	115.55	123.53	116.22	117.08	-1.30%
TTS B3-B4	235.18	247.57	241.01	243.18	-3.29%
WMTS	63.85	68.25	62.23	62.87	1.56%
Total non-coincidental	**1022.15**	**1094.19**	**1024.43**	**1041.72**	**-1.88%**

Minimum demand

The observed terminal station minimum demand was within ±6 MW of the 50% POE forecast at all Terminal stations except for Thomastown (TTS B3-B4). The higher minimum demand observed at TTS B3-B4 indicates that the minimum demand at this terminal station did not decline as much as forecast due to various factors and is reflected in the 2023 forecast. The total non-coincidental minimum demand of all terminal stations was higher compared to the 50% POE forecast however JEN considers this difference to the system-level minimum demand forecast acceptable considering the various drivers and factors that can influence minimum demand.

Table 4-6: Comparison of terminal station observed minimum demand to JEN's 2022 forecast

Terminal Station	50% POE (MW)	10% POE (MW)	Actual mD (MW)	MW Difference (compared to 50% POE)
BLTS66	35.9	32.2	37.9	2.0
BLTS22	0.5	0.4	0.1	-0.4
BTS	10.7	9.1	11.9	1.2
KTS B1-B2	46.6	40.5	47.9	1.4
KTS B3-B4	-6.6	-9.6	-5.9	0.7
SMTS	-9.1	-17.5	-9.3	-0.1
TSTS	4.7	4.2	4.5	-0.2
TTS B1-B2	22.0	11.9	26.6	4.6
TTS B3-B4	25.4	9.4	33.2	7.8
WMTS	13.0	11.5	15.9	2.8
Total non-coincidental	**143.0**	**92.1**	**162.8**	**19.8**

4.3.3 Zone substation forecast

Maximum demand

As shown in Table 4-7, the observed zone substation maximum demand was within 10% of the 50% POE forecasts, for all zone substations) Braybrook (BY), East Preston (EPN), Fairfield (FF), North Essendon (NS), Sunbury (SBY) and Yarraville (YVE) These were mainly caused by the different timing of customer load uptake or planned transfers. However, the total non-coincidental maximum demand of all zone substations was within 1.46% of the 50% POE forecast.

Table 4-7: Comparison of zone substation observed maximum demand to JEN 2022 forecast

Zone Substation	50% POE (MW)	10% POE (MW)	Actual MD (MW)	Temp. Adjusted MD (MW)	% Difference (compared to 50% POE)
Airport West	66.92	71.22	69.62	70.19	-4.66%
Braybrook	35.56	38.36	44.56	45.05	-21.06%
Broadmeadows	71.10	75.11	69.96	70.36	1.06%
Broadmeadows South	33.09	34.95	32.46	33.46	-1.11%
Coburg North	49.86	53.86	50.96	51.51	-3.20%
Coburg South	44.77	48.78	44.45	45.04	-0.60%
Coolaroo	37.92	41.79	36.70	37.19	1.97%
East Preston-A	7.40	7.55	6.81	6.81	8.68%
East Preston-B	12.91	13.44	12.05	12.24	5.52%
East Preston-22 kV	14.20	15.32	10.73	10.83	31.18%
Essendon	42.37	46.07	44.66	45.26	-6.39%
Fairfield	29.82	31.51	18.56	23.78	25.42%
Flemington	22.69	24.30	23.00	23.23	-2.31%
Footscray East	36.57	39.06	34.08	34.40	6.32%
Footscray West	38.27	40.32	37.32	37.49	2.08%
Heidelberg	26.22	28.24	27.02	27.35	-4.14%
Kalkallo[21]	20.99	21.96	21.00	21.42	-2.01%
Newport	56.48	60.94	60.55	61.11	-7.58%
North Essendon	31.68	36.01	38.09	38.76	-18.26%
North Heidelberg	37.02	39.91	34.94	35.36	4.71%
Preston	28.01	30.13	29.70	30.06	-6.82%
Pascoe Vale	35.16	39.61	38.36	39.04	-9.93%
Somerton	72.13	75.46	70.10	71.50	0.88%
Sunbury	41.83	45.05	45.24	46.78	-10.58%
Sydenham	41.35	44.19	39.60	41.25	0.23%
Thomastown	29.85	32.65	30.72	31.71	-5.89%
Tottenham	27.75	28.33	25.94	25.94	6.95%
Tullamarine	24.34	25.91	24.55	24.75	-1.65%
Yarraville	40.90	43.56	29.73	30.98	32.01%
Total non-coincidental	**1057.18**	**1133.57**	**1051.47**	**1072.86**	**-1.46%**

[21] Kalkallo and Thomastown Zone Substations are shared with AusNet Services. The load forecasts are based on Jemena's load only.

Minimum demand

As shown in Table 4-7, the observed zone substation minimum demand was within 3 MW of the 50% POE forecast at all zone substations except for Footscray West (FW), Somerton (ST) and Tullamarine (TMA). The higher minimum demand observed at both ST and TMA indicates that the minimum demand at these zone substations did not decline as much as forecast due to various factors and this is reflected in the 2023 forecast. The lower minimum demand observed at FW indicates that the minimum demand at this zone substation has a more rapid decline compared to the forecast and this is reflected in the 2023 forecast. The total non-coincidental minimum demand of all zone substations was marginally higher compared to the 50% POE forecast however JEN considers this difference to the system-level minimum demand forecast acceptable considering the various drivers and factors that can influence minimum demand.

Table 4-8: Comparison of zone substation observed minimum demand to JEN 2022 forecast

Zone Substation	50% POE (MW)	10% POE (MW)	Actual mD (MW)	MW Difference (compared to 50% POE)
Airport West	11.0	8.1	12.2	**1.2**
Braybrook	8.3	7.7	10.9	**2.6**
Broadmeadows	2.3	-3.3	2.5	**0.2**
Broadmeadows South	9.7	8.9	12.4	**2.7**
Coburg North	8.7	5.6	8.9	**0.3**
Coburg South	4.5	3.2	4.2	**-0.4**
Coolaroo	-4.7	-7.1	-7.0	**-2.3**
East Preston-A	0.4	-0.3	1.0	**0.6**
East Preston-B	1.4	0.6	1.7	**0.3**
East Preston-22 kV	1.5	1.3	1.9	**0.4**
Essendon	6.8	6.6	6.9	**0.2**
Fairfield	2.2	0.9	3.3	**1.1**
Flemington	9.2	8.5	8.9	**-0.3**
Footscray East	3.6	3.2	3.6	**0.0**
Footscray West	9.2	7.9	5.3	**-3.9**
Heidelberg	4.9	4.4	4.5	**-0.4**
Kalkallo[22]	-11.1	-12.9	-11.6	**-0.6**
Newport	7.0	6.4	6.6	**-0.4**
North Essendon	7.5	7.3	7.4	**-0.1**
North Heidelberg	15.3	14.5	12.5	**-2.8**
Preston	4.7	3.5	6.6	**1.9**
Pascoe Vale	4.6	3.9	4.6	**0.0**
Somerton	-1.8	-8.9	1.9	**3.7**
Sunbury	0.3	-1.1	-2.3	**-2.7**
Sydenham	-4.0	-5.7	-2.2	**1.8**
Thomastown	2.9	1.5	4.2	**1.3**

[22] Kalkallo and Thomastown Zone Substations are shared with AusNet Services. The load forecasts are based on Jemena's load only.

Zone Substation	50% POE (MW)	10% POE (MW)	Actual mD (MW)	MW Difference (compared to 50% POE)
Tottenham	5.4	2.4	5.8	**0.4**
Tullamarine	3.5	1.6	8.7	**5.2**
Yarraville	6.3	4.6	6.5	**0.2**
Total non-coincidental	**119.6**	**73.2**	**129.8**	**10.2**

5. Network Development

This section outlines the existing and emerging network limitations identified throughout the planning review process and information about recently completed projects and committed network developments covering the forward planning period (2024 to 2028). These existing and emerging limitations can be a result of asset conditions, thermal and fault level capacity, or power quality issues.

To facilitate non-network service provider solutions, the expected impact of identified limitations is outlined, including the hours per year that load is at risk of not being serviced, and the amount of load reduction that would be required to defer or mitigate risks associated with each network limitation.

Potential solutions to mitigate network limitation risks are also presented, along with the augmentation option and timing that JEN considers most likely to occur based on the option's ability to economically maximise the reliable supply of electricity. In all cases, solutions will include asset replacements, refurbishments, or augmentations.

All costs presented in this DAPR are total project costs and are presented in real June 2023 dollars, unless otherwise stated.

5.1 Network Augmentation Projects

This section presents the proposed preferred network augmentation options and their indicative timing to manage the identified network limitations with details on the risk assessment shown in our interactive map via the digital DAPR. This development plan is based on current network conditions and JEN's 2023 Demand Forecasts Report. Any party considering an investment (or potential deferral of a proposed investment) based on this development plan should first consult JEN for specific, detailed, and up-to-date network development information.

Table 5-1 lists the committed (or about to be committed) network augmentation projects for 2024. Table 5-2 through to Table 5-5 presents JEN's proposed network augmentation plans for the 2024-2028 period. Further details on the network limitations, load forecast, historic load traces and augmentation projects are provided in our interactive map via the Digital DAPR[23] using the reference provided in the tables below.

There are no augmentation projects with an estimated capital cost of $2 million or more in the forward planning period that are to address an urgent and unforeseen network issue.

Table 5-1: 2024 network augmentation plans

Network limitation	Preferred network solution	Digital DAPR map reference
KLO-13 capacity constraint	Reconfigure KLO-21 (committed)	KLO zone substation
HB-15 feeder thermal capacity constraint	New Feeder HB-21 (committed)	HB zone substation

[23] https://dapr.jemena.com.au/

Table 5-2: 2025 network augmentation plans

Network limitation	Preferred network solution	Digital DAPR map reference
BTS-FF subtransmission loop thermal capacity constraint	Augment BTS-FF loop	BTS-FF-BTS 22 kV loop
FT-11 feeder thermal capacity constraint	Reconfigure feeder FT-11 and FT-15	FT zone substation
EP asset condition and thermal capacity	Stage 6 East Preston area conversion (committed)	EP zone substation
FT-21 feeder thermal capacity constraint	Establish a new feeder FT-12	FT zone substation
SBY-24 feeder thermal capacity constraint	Reconfigure feeder SBY-24	SBY zone substation
SBY-13 feeder voltage constraint	Install voltage regulator feeder SBY-13	SBY zone substation

Table 5-3: 2026 network augmentation plans

Network limitation	Preferred network solution	Digital DAPR map reference
EP asset condition and thermal capacity	Stage 7 East Preston area conversion	EP zone substation
BD-08, BD-13 and ST-34 feeder thermal capacity constraint	Reconfigure BD and ST feeders	BD zone substation
BY 22kV supply reliability	Reconfigure feeders at BY 22kV buses	BY zone substation
COO-23 capacity constraint	Reconfigure feeders COO-13, COO-21 ST-21	COO zone substations
ES-11 thermal capacity constraint	New feeder ES-31	ES zone substation
FF-96 thermal capacity constraint	Augment feeder FF-96	FF zone substation
FT-22, FT-32 and FT-33 thermal capacity constraint	New feeder FT-12	FT zone substation
SBY-24 thermal capacity	Augment steel section of SBY-24	SBY zone substation
SHM-14 thermal capacity constraint	New feeder SHM-13	SHM zone substation

Table 5-4: 2027 network augmentation plans

Network limitation	Preferred network solution	Digital DAPR map reference
SHM and SBY capacity constraint	Upgrade two transformers at Sunbury (SBY) zone substation	SBY and SHM zone substations
BTS-NS 22 kV subtransmission thermal capacity constraint	Augment BTS-NS 22 kV subtransmission	BTS-NS-BTS 22 kV loop
COO, ST and KLO thermal capacity constraints	Establish a new zone substation Craigieburn (CBN)	COO, KLO and ST zone substations
CS-5 thermal capacity constraint	Augment feeder CS-5	CS zone substation
NH-02 thermal capacity constraint	Augment section NH-08	NH zone substation
SHM-11 thermal capacity constraint	New feeder SBY-14	SHM zone substation
TTS-NEI-NH-NEL-WT subtransmission loop thermal capacity constraint	Augment TTS-NEI-NH-NEL-WT subtransmission	TTS-NEI-NH-NEL-WT loop

Table 5-5: 2028 network augmentation plans

Network limitation	Preferred network solution	Digital DAPR map reference
EP asset condition and thermal capacity	Stage 8 East Preston area conversion	EP zone substation

FT-32 thermal capacity constraint	New feeder FT-25	FT zone substation
SBY-23 feeder voltage constraint	Install voltage regulator SBY-23	SBY zone substation
SBY-24,SBY-32 and SBY-13 thermal capacity constraint	New feeder SBY-22	SBY zone substation
TT-11 thermal capacity constraint	Augment feeder TT-11	TT zone substation

5.2 Network Asset Replacement Projects

This section presents the proposed preferred options and their indicative timing to manage the replacement of network assets that have reached the end of their life in accordance with Schedule 5.8 clause (b1) of the NER. Unless otherwise stated within Table 5-6 to Table 5-10: 2028 network asset replacement plans

if the network replacement project is committed (or about to be committed), the asset replacement proposals are uncommitted and still subject to JEN's project approvals process and procurement of appropriate funding. Any party considering an investment (or potential deferral of a proposed investment) based on this replacement plan should first consult JEN for specific, detailed, and up-to-date network asset information.

Further details on the network limitations, load forecast, historic load traces and replacement projects are provided in our interactive map via the Digital DAPR using the reference provided in the tables below.

There are no replacement projects with an estimated capital cost of $2 million or more in the forward planning period that are to address an urgent and unforeseen network issue.

Table 5-6: 2024 network asset replacement plans

Network limitation	Preferred network solution	Digital DAPR map reference
HB transformer asset condition	Replace HB transformers (committed)	HB zone substation

Table 5-7: 2025 network asset replacement plans

Network limitation	Preferred network solution	Digital DAPR map reference
FW transformer switchgear and relay asset condition	Replace 22 kV transformer switchgear and relays at FW (committed)	FW zone substation
FW CB asset condition	Replace 66 kV circuit breakers at FW (committed)	FW zone substation
FW capacitor bank asset condition	Replace capacitor bank CB's FW (committed)	FW zone substation
NH, NEI, and TTS relay asset condition	Replace 66 kV line and bus and 22 kV bus relays at NH, NEI and TTS	NH zone substation
FT isolator asset condition	Replace 66 kV isolators and earth switches	FT zone substation
FF transformer asset condition	Replace FF No.3 transformer	FF zone substation

Table 5-8: 2026 network asset replacement plans

Network limitation	Preferred network solution	Digital DAPR map reference
NS relay asset condition	Replace aged relays at NS	NS zone substation
BLTS 22 kV switchgear asset condition	Replace 22 kV switchgear - BLTS	BLTS terminal station

Table 5-9: 2027 network asset replacement plans

Network limitation	Preferred network solution	Digital DAPR map reference
CN 66 kV CB asset condition	Replace 66 kV 1-2 bus-tie and 66 kV line circuit breaker at CN	CN zone substation
CN switchgear and relay asset condition	Replace 22 kV switchgear and relays at CN	CN zone substation

Table 5-10: 2028 network asset replacement plans

Network limitation	Preferred network solution	Digital DAPR map reference
CS switchgear and relay asset condition	Replace 22 kV switchgear and relays at CS	CS zone substation

5.3 Changes Since the 2022 Report

Major changes since the 2022 DAPR, which are included in this report, are information related to the forecast use of distribution services by embedded generating units and associated network limitations (in accordance with the new reporting requirements of clause 5.13.2 and schedule 5.8 of the NER). This additional information is discussed throughout the report, which covers:

- Minimum demand (or peak supply) forecasts at the different network levels;
- Export ratings at the different network levels;
- Emerging export limitations and potential solutions that may address the forecast export limitations;
- Estimated reduction in embedded generation that would defer a forecast export limitation; and
- Minimum demand forecast methodology and network planning methodologies relating to export limitations and export ratings determination.

In the past 12 months, JEN has completed the following major network upgrade projects:

- Reconfigure feeder ES-23
- COO and ST feeders' capacity constraints
- EP conversion stage 5
- Reconfigure feeder YVE-21
- Install REFCLs at COO and reconfigure feeders
- Underground sections of KLO-22 and reconfigure feeders
- Augment the KTS-BY-ES-KTS 66 kV loop

In addition, the following major network upgrades (which are committed projects) are expected to be completed in 2024:

- Reconfigure feeder KLO-21
- New feeder HB-21

JEN has digitalised the majority of the content within the DAPR report into a user-friendly interactive map, which presents JEN's electricity network, terminal station supply points, subtransmission lines, zone substations, HV distribution feeders and distribution substations.

The interactive digital DAPR map is effectively our network development plan, which contains our demand forecasts, network limitations, risk assessment and information about our committed and proposed network augmentation and replacement projects on our transmission connection assets, subtransmission lines, zone substations and HV distribution feeders.

5.4 Grouped Network Asset Replacement Programs

This section outlines the ongoing asset replacement programs that JEN has in place for assets that have individual replacement costs of less than $200k in accordance with Schedule 5.8 clause (b2) of the NER.

5.4.1 Poles

Poles are utilised for the support of the overhead electricity network and for public lighting where an underground electricity network is installed. These assets are located across the entire network and are manufactured from various materials including wood, concrete and steel constructions. JEN's pole replacement programs are intended to maintain network reliability, mitigate the associated safety risks arising from in-service failure of poles due to poor condition and meet JEN's regulatory obligations.

JEN employs a condition-based approach to the replacement and refurbishment of poles but uses a combination of age and condition to forecast the volume of replacements required. Poles that are deemed unserviceable are either staked (reinforced) or replaced. The condition of the pole is the primary driver for staking or replacement.

After inspection and testing the condition of a pole is classified as either Serviceable, Limited Life or Unserviceable. These pole conditions are defined as follows:

- Serviceable – may remain in service until the next routine inspection;
- Limited Life – must be reinstated (by staking) or reassessed within 12 months; and
- Unserviceable – must be reinstated (by staking) or replaced within 12 weeks.

The forecast replacement volumes are based on CBRM modelling. The CBRM model is an integrated tool designed to systematically analyse the condition of ageing assets and optimise investments while maintaining network reliability. Modelling results are detailed in each relevant Asset Class Strategy (**ACS**).

5.4.2 Pole top structures

Pole top structures include cross-arms, insulators, insulator ties, braces, bird covers, bolts, surge diverters and associated hardware mounted on or near the top of a pole. Similar to poles, these assets are located across the entire JEN overhead electricity network.

Asset inspectors monitor the condition of the pole and every asset attached to the pole. The scope of this strategy includes wood poles (prevention of climbing animals), transformer bushings, crossarms, crossarm braces, bolts, insulators, conductors, bird and animal covers, fuse brackets, cable terminations and surge arrestors. These inspections determine the preventive maintenance and planned replacement of pole top structures.

Utilising the same methodology applied to pole replacements, CBRM modelling is used to determine the replacement volumes. Modelling results are detailed in the associated ACS.

5.4.3 Distribution equipment

Distribution equipment consists of HV and LV assets that are utilised in the distribution of electricity. This category consists of distribution transformers and their switches including HV switches, HV isolators, LV switchgear, LV isolators and kiosks. Similar to poles, these assets are located across the entirety of the JEN network.

The augmentation of these assets is largely driven by the need for proactive replacement to upgrade the installations to meet increasing capacity requirements. This impacts the number of assets that would otherwise be replaced because they have reached the end of life. In general, an inspection of distribution equipment is carried out as part of the standard asset inspection program and reactive maintenance is conducted to rectify defects as required.

Utilising the same methodology for replacement as with Poles, CBRM modelling is used to determine the replacement volumes. Modelling results are detailed in the associated ACS.

5.4.4 Overhead conductor

Overhead conductors in use across the JEN include All Aluminium Conductor (AAC), Aluminium Conductor Galvanised Steel Reinforced (ACSR), Copper Conductors, Cadmium Copper Conductors, Galvanised Steel Conductors, and Low Voltage Aerial Bundled Conductor (LV ABC). Similar to poles, these assets are located across the entire JEN overhead network.

Inspection of conductors and connectors is conducted as part of the overhead line inspection program. Thermal surveys and corona discharge tests are conducted to identify high-impedance connections.

Routine condition-based replacement of conductor and connectors are an ongoing activity for JEN. This replacement program is required to maintain network reliability and mitigate the associated safety risks arising from in-service failure of conductors and connectors that are in poor condition.

5.4.5 Underground cables

Underground distribution systems consist of subtransmission cables entering and exiting zone substations, HV cables for distribution to HV customers via pole and non-pole type substations, and low-voltage distribution to customers also via transformation at pole and non-pole type substations. These assets are located across the entire JEN network.

JEN's underground cable systems are generally employed on a run-to-failure basis due to their high-reliability performance and a large part of the systems cannot be readily inspected visually. The repair or replacement of any faulted underground cable system is an ongoing activity.

5.4.6 Services

Services refer to the conductors and associated hardware that connect customers' premises to the overhead low-voltage distribution network. Defective services are one of the main safety risks to customers and they also have adverse impacts on customers' supply reliability. On occasions where they fail catastrophically, they can also lead to fire starts. Defective services include those that do not have sufficient ground clearances as they are a safety hazard to traffic and the public.

It is a regulatory requirement for services to contain a neutral conductor that is continuous from any point of supply to the neutral terminal of the substation it is connected to. Neutral continuity and impedance are measured using daily AMI metering data analytics.

Neutral Supply Tests (NST) will continue for customers who do not have AMI metering on a ten-year cycle.

Routine inspection and testing of services are mandated by the Electricity Safety (Bushfire Mitigation) Regulations 2023. Defective services identified during inspection and testing are replaced.

In addition to this routine replacement, JEN is undertaking a program to replace non-standard LV overhead services. The program commenced in 2010.

The Electricity Safety (General) Regulations 2019 define ground clearance requirements for low-voltage aerial lines. Complying with these regulations is now included in JEN's Electricity Safety Management Scheme (ESMS).

LV ABC is the standard service cable type due to its durability and low representation in neutral failure statistics.

Other types of non-standard service cable are replaced by LV ABC, as the deterioration of the neutral conductors poses a threat to both reliability of supply and public safety.

5.4.7 Earthing

Distribution earthing

A variety of earthing systems have been historically used across the JEN distribution substation network and these have included:

- Separate HV and LV earthing systems;
- Combined HV and LV earthing systems; and
- Common HV and LV earthing systems.

In general, except for zone substation earthing systems, there is no requirement to inspect and test HV earthing installations that form part of a CMEN system. The inspection and testing of HV earthing systems installed outside CMEN schemes and zone substations are required at 10-yearly intervals, in accordance with JEN's Electricity Safety Management Scheme (ESMS). The testing of these earths is carried out as part of the HV Earth Testing Program in Non-CMEN Areas.

The HV earths that require rectification to bring the earth resistance to an acceptable level in non-CMEN Areas are being addressed as an ongoing program.

Zone substation earthing

Testing of zone substation earth grids is undertaken at 10-year intervals to ensure they continue to comply with safety criteria. Sample inspections of underground conductors and conductor joints are conducted to check for any corrosion or damage. A grid continuity test is also to be conducted as a part of the testing. In addition to the 10-yearly testing, annual physical integrity inspections are undertaken for all above-ground structure earth-to-earth grid connections for all HV and LV equipment. If issues are identified during the inspection program, mitigation works will be carried out to ensure the integrity of the zone substation's earth grid is compliant with safety criteria.

5.4.8 Zone substation protection and control

Protection relays

Protection and control equipment within a zone substation is used to detect the presence of a network fault and/or other abnormal operating conditions and then to automatically initiate action to either isolate the network fault or correct the abnormal condition by some pre-defined control sequence.

Protection and control equipment is replaced based on condition in a proactive and planned way. If any protection and control equipment is not fit for service based on condition or exhibiting symptoms of age-related deterioration, those will be proactively replaced. This option is considered the most prudent option as it balances maximising the asset life and minimising the failure risk. It is usual for the entire protection scheme to be replaced with its modern-day equivalent at the time of replacement.

Following recent relay failures, JEN maintains a strategy to replace the existing relays to ensure the ongoing reliability of supply to its customers.

In the forward planning period, JEN will undertake bulk relay replacements at:

- Footscray West (FW) Zone Substation in 2024/25;
- 66kV Protection at North Heidelberg Zone Substation (NH), Nilsen (NEI) and Thomastown Terminal Station (TTS) in 2026;
- Coburg North (CN) Zone Substation and 11kV Protection at North Essendon Zone substation in 2027; and
- Coburg South (CS) and North Heidelberg Zone Substation in 2027-28.

Power quality meters

JEN's power quality monitoring systems continuously monitor the voltage supply at zone substation 6.6 kV, 11 kV and 22 kV buses, and at the end of feeder locations within the distribution network. Within zone substations, the power quality meters monitor the network via suitably rated voltage and current transformers. At the end of feeder distribution substations, the power quality meters are connected directly to the low-voltage network to monitor steady-state voltages and voltage variations.

The fleet of power quality meters is ageing and some meters have reached obsolescence. There have been several hardware failures over recent years and there is increasing concern about the reliability of the power quality data obtained from these meters.

As such, JEN has initiated a planned replacement program in which all of the deteriorating zone substation power quality meters will be replaced by modern devices. End-of-feeder power quality meters have previously been replaced.

Battery banks and chargers

DC supply systems are one of the most critical assets in a zone substation. The DC supply system consists mainly of battery banks and battery chargers designed to support the standing and momentary DC loads of a zone substation. Under normal operating conditions, the battery charger supplies the DC loads as well as keeps the battery banks fully charged. In the event of the charger not being able to charge the batteries e.g. due to failure of the charger or due to interruption of AC supply input to the charger, the battery bank must seamlessly support the zone substation DC loads for a designated period.

DC supply system equipment is replaced based on condition in a proactive and planned way.

These assets are at risk of failure due to age-related deterioration and irreversible temperature-related thermal degradation.

In the forward planning period, JEN plans to replace batteries and chargers at the following zone substations that have reached their end of life:

- Somerton (ST) and Tottenham (TH) in 2023;
- Nilsens Electrical Industries (NEI), Visy Coolaroo (VCO) and Yarraville (YVE) in 2024; and
- Broadmeadows South (BMS), Tullamarine (TMA) and East Preston (EPN) in 2025.

5.4.9 Zone substation primary equipment

Instrument transformers

Standalone Voltage Transformers (**VT**) and Current Transformers (**CT**) are high-accuracy class electrical devices used to transform voltage or current levels. The most common usage of these transformers is to operate instruments or metering from high-voltage or high-current circuits, safely isolating secondary control circuitry from the high voltages or currents.

A suitable and targeted condition monitoring program has been developed to establish VT and CT conditions so that condition-based replacement can be planned as required. This program has been employed to test VTs and CTs over 40 years old.

There are currently no VT and CT replacements scheduled in the forward planning period.

Insulators

Arcing discharge, surface tracking and cracked porcelain have been witnessed on the 66 kV brown pin insulators, warranting their replacement. Pin and cap-type porcelain insulators exhibit similar structural issues. These insulators are installed at various zone substations. There have been several failures of this type of insulator across other distribution networks nationally. These replacements will be combined with larger switchgear replacement projects at the respective zone substations.

5.4.10 Communications and SCADA

Communication and Field SCADA assets

The communication and field Supervisory Control and Data Acquisition (SCADA) assets provide services to SCADA, protection relays, Power Quality Meters (**PQM**), Remote Controllable Gas Switches (**RCGS**), Automatic Circuit Reclosers (**ACR**), Ring Main Units (**RMU**) and smart metering.

Replacing communication and field SCADA assets is planned based on their performance and the technical end of their asset life. The replacement will be performed immediately after an asset failure. Table 5-11 below shows the communications and field SCADA asset types used in JEN and their specified asset life.

Table 5-11: Communication and Field SCADA asset replacement details

Asset Type	Volume	Asset Life Expectancy (Years)
Ruggedcom Switches	85	20
ABB Switches	22	15
Other network devices - Routers and Firewall	2 routers	10
MDS iNet radio transceivers	104	15
Trio radio transceivers	267	15
3G modems	50	17*
4G Modems	26	10
Copper cables	~16 km in service Cu cable	50
Fibre optic cable	~315km	50
GPS Clock	27	20
GPS time servers	6	20
Remote Terminal Units (RTU)	35	20
Multiplexers	90	20
MPLS	20	15
Voice Frequency (VF)	9 VF circuits, 18 cards	40
Unmanaged ethernet switches	106	12
Managed field ethernet switches	20	8
Radio Access Points	32	15
Fault Indicators	40	15
AMI Relays	340	15
AMI Access Point	111	10
AMI Batteries	451	5

* Life expectancy is until June 2024 when the 3G network is turned off and the 3G-only devices need to be upgraded, which is estimated at 45 devices.

SCADA

The reliability of the JEN SCADA, Advanced Distribution Management System (**ADMS**) and Outage Management Systems (**OMS**) is critical to the safe and reliable supply of energy to JEN customers. These core systems were replaced in the last quarter of 2020 with a contemporary SCADA system that allows JEN to take advantage of advanced features now and into the future.

5.5 Network Limitations and Jemena's Digital DAPR

5.5.1 Distribution system limitation report

On 8 December 2016, the Australian Energy Market Commission (**AEMC**) published its final determination on the proposed *Local Generator Network Credit* rule change[24].

The final rule (clause 5.13.3 of NER) requires DNSPs to publish a 'system limitation report' in accordance with a template prepared by the Australian Energy Regulator (**AER**)[25], which includes information:

- The name and location of network assets where a limitation has been identified;
- The timing of the limitation;
- The proposed solution;
- The estimated cost of the proposed solution; and
- The amount by which peak demand would need to be reduced to defer the proposed solution and the dollar value of each year of deferral.

The Distribution System Limitation Report, together with the historic load traces, are included in our digital DAPR map[26].

5.5.2 JEN's Digital DAPR Interactive Map

In 2020, JEN digitalised the majority of the content within our DAPR into a user-friendly interactive map that provides a visual representation of the existing and emerging identified constraints.

The digital DAPR map presents JEN's electricity network, terminal station supply points, subtransmission lines, zone substations, HV distribution feeders, and distribution substations including its forecast load, historic load traces, network limitations, risk assessment and information about our committed and proposed network augmentation and replacement projects.

JEN consulted with our end users on the useability and information contained in the digital DAPR map and has incorporated our customers' feedback into the production of Jemena's digital DAPR.

24 http://www.aemc.gov.au/Rule-Changes/Local-Generation-Network-Credits

25 https://www.aer.gov.au/system/files/DAPR%20Template%20V%201%20-%20June%202017.pdf

26 https://dapr.jemena.com.au/

5.6 Summary of Joint Planning Outcomes

5.6.1 TNSP joint planning

Table 5-12 summarises the planning outcomes for Jemena's transmission connection points undertaken as part of and presented in the 2023 Transmission Connection Planning Report (TCPR), for JEN's ten-year forward planning period.

Table 5-12: Jemena Connection Points

Connection Point	2023 TCPR Outcome
Brunswick Terminal Station (22 kV) (BTS 22 kV)	No augmentation of capacity is required.
Brooklyn Terminal Station (22 kV) (BLTS 22 kV)	No augmentation of capacity is required.
Brooklyn Terminal Station (66 kV) (BLTS 66 kV)	Install an additional 150 MVA 220/66kV transformer at either BLTS or ATS.
Keilor Terminal Station (KTS)	Install a third 150 MVA 220/66kV transformer at KTS B34 bus group and transfer loads from KTS B125 to KTS B34.
South Morang Terminal Station (SMTS)	Install a third 225 MVA 220/66kV transformer.
Templestowe Terminal Station (TSTS)	Install a fourth 150 MVA 220/66kV transformer.
Thomastown Terminal Station (TTS)	No augmentation of capacity is required.
West Melbourne Terminal Station (WMTS)	No augmentation of capacity is required.

There have been no material changes to joint planning undertaken between JEN and AusNet Services or AEMO in the preceding year.

5.6.2 DNSP joint planning

In the preceding year, there were no material joint planning changes for the subtransmission assets shared by JEN and surrounding DNSPs, which are listed in Table 2-1.

Recognising the inter-relationships between JEN's Coolaroo (**COO**) and AusNet Services Kalkallo (**KLO**) zone substations, in 2019 JEN and AusNet Services engaged consultants WSP to assist in a joint planning exercise to examine several technical design options and determine the most efficient cost of meeting the requirements of the Electricity Safety (Bushfire Mitigation) Regulations across both COO and KLO supply areas over the long term.

Through this process, we identified that there was only one option that did not require any exemptions from the requirements of the Electricity Safety (Bushfire Mitigation) Regulations. However, this option is not economical nor does it address the long-term interest of our customers as there are significant technical limitations to the REFCL technology.

As such, JEN implemented an alternative solution where all sections of HV feeder in the COO and KLO supply areas with a high risk of bushfire ignition will meet the REFCL performance standard, and all lower bushfire ignition risk areas will be treated with alternative bushfire ignition prevention measures where required, such as an underground cable or low-performance REFCL.

JEN has applied for, and been granted, exemptions to the Act and Regulations for sections of the COO and KLO supply areas that will not meet the REFCL performance standard. This solution provides a bushfire risk-neutral outcome compared with the installation of REFCL to meet the performance requirements across the whole COO and KLO supply area.

This option requires augmentation of the network including installing two new REFCLs at COO, network hardening and balancing on COO and KLO feeders, and feeder augmentation and reconfiguration works. Refer to Section 5.10 for more information.

5.7 Summary of RIT-D Applications

JEN has completed three Regulatory Investment Tests for Distribution (**RIT-Ds**) since publishing the 2022 DAPR. Jemena also intends to commence an additional two replacement and five augmentation RIT-D assessments within the forward planning period (2024-2028).

The recently completed RIT-Ds are:

- Brunswick Terminal Station – Fairfield Zone Substation 22 kV subtransmission loop capacity constraint.
- Footscray West Zone Substation Transformer, Switchgear and Relay condition risk.
- Fairfield zone substation transformer No.3 condition and 4th bus.

There are no augmentation RIT-Ds that are currently in progress.

JEN intends to commence the following two replacement projects RIT-Ds in the forward planning period:

- Coburg North Zone Substation (**CN**) switchgear and relay condition in June 2025 (see CN zone substation risk assessment in the digital DAPR); and
- Coburg South Zone Substation (**CS**) switchgear and relay condition in June 2026 (see CS zone substation risk assessment in the digital DAPR).

JEN intends to commence the following six augmentation projects RIT-Ds in the forward planning period:

- East Preston (EP) conversion Stage 7 and Stage 8 (see section EP zone substation risk assessment in the digital DAPR) in June 2024;
- Brunswick Terminal Station – North Essendon Zone Substation 22 kV subtransmission loop capacity constraint in June 2025;
- New Feeder SHM-013 to alleviate SHM-014 feeder thermal constraint in June 2024;
- Coolaroo, Somerton and Kalkallo capacity constraint in October 2024;
- Thomastown-NEI-North Heidelberg-NEL-Watsonia 66 kV loop capacity constraint in March 2025; and
- Sydenham and Sunbury area capacity constraint in June 2025.

5.7.1 Brunswick Terminal Station – Fairfield Zone Substation 22 kV subtransmission loop capacity constraint

Identified need

JEN's Fairfield Zone Substation (**FF**), located at the corner of Station St and McGregor St, supplies approximately 6,756 JEN customers and 3,664 CitiPower customers (predominantly residential) at 6.6 kV in Fairfield and Alphington in the JEN supply area, and parts of Thornbury in the CitiPower supply area. The zone substation is supplied by three 22 kV subtransmission lines that originate from AusNet Services' Brunswick Terminal Station (**BTS**).

Electricity demand in the FF supply area is expected to grow on average at 6.5% per annum over the next five years. The expected increase in demand is mainly driven by the current and proposed residential and commercial developments at the former Amcor Paper Fairfield site, known as YarraBend. The existing 22 kV subtransmission lines supplying FF from BTS are currently fully utilised and will not have sufficient capacity to meet the increasing demand.

The subtransmission lines are currently operating above their N-secure rating.[27] Under the worst-case single contingency condition, the loading on the subtransmission lines reaches 127.5% utilisation by summer 2026, which will require JEN to take customers off supply.

[27] JEN acceptable loading on the subtransmission line under system normal to maintain supply reliability during single contingency (N-1) condition.

Based on the current forecast on a single contingency event for summer 2023-24, approximately 4.5 MVA of load will be shed around the Fairfield and Alphington area to maintain the operation of the lines within their safe thermal loading limits. This will leave approximately 1,200 customers off supply during an outage on the subtransmission line.

In addition, all three subtransmission lines share the same pole line with another line (from the same loop) for all or part of the route, increasing the likelihood of a single outage taking out two of the three 22 kV lines. In the event of this outage condition, this will leave approximately 6,000 customers off supply.

Operating overhead conductors above their thermal ratings could lead to excessive sag and may cause long-term damage. The substandard conductor clearance could lead to accidents, such as vehicles contacting low overhead conductors and sagged 22 kV lines being in contact with its subsidiary overhead circuits.

RIT-D status

On 11 September 2023, Jemena published Stage 2 of the Brunswick Terminal Station – Fairfield Zone Substation 22 kV subtransmission loop capacity constraint RIT-D, the Draft Project Assessment Report (DPAR). The DPAR assessed possible options for economically mitigating the supply risks at Fairfield and identified the preferred option to manage the forecast supply risk in the area as summarised below. Jemena did not receive any submissions on this DPAR, therefore the following section constitutes the Final Project Assessment Report (FPAR) for this RIT-D project.

Options considered in RIT-D

The credible network options and the net economic benefits that were assessed to alleviate the current and emerging capacity overload limitations on the BTS-FF 22 kV subtransmission lines:

- Option 1: Do nothing (Base Case);
- Option 2: Reinforce supply to FF and surrounding areas from the adjacent Heidelberg (HB) substation. This will assist in reducing the load-at-risk on the BTS-FF lines;
- Option 3: Augment the BTS-FF 22 kV subtransmission loop by installing a new fourth line from BTS to FF using a single cable. This will assist in reducing the load-at-risk and losses on the BTS-FF lines.
- Option 4: Augment the BTS-FF 22 kV subtransmission loop by installing a new fourth line from BTS to FF using twin cables. This will assist in reducing the load-at-risk and losses on the BTS-FF lines; and
- Option 5: Combine the existing BTS-FF 184 and BTS-FF 188 lines and augment the BTS-FF 22 kV subtransmission loop by installing a new third line from BTS to FF using twin cables. This will assist in reducing the load-at-risk and losses on the BTS-FF lines.

As part of the RIT-D process, JEN considered the credibility of potential non-network options as alternatives to the network options listed above. A Non-Network Options Report, published on JEN's website on 22 September 2021, was prepared to establish whether a non-network solution is potentially available to address the identified need. The Non-Network Options Report was predicated on the need for a non-network option to reduce the expected unserved energy risk that would otherwise have been addressed by a network solution. From the consultation on the Non-Network Options Report that closed on 15 December 2021, JEN did not receive any submissions that identified a viable non-network alternative solution.

Project outcome

Jemena has identified that Option 5 to combine the existing BTS-FF 184 and BTS-FF 188 lines and augment the BTS-FF 22 kV subtransmission loop with a new third line from BTS to FF using twin cables will address the project's identified needs and is the option that maximises the net market benefits to consumers compared with all the other options.

Based on this analysis, this project is progressing to the business case stage and is planned for completion by November 2025.

The estimated construction timetable is as follows:

- Business case approval: April 2024;
- Primary/distribution design complete: October 2024;
- Secondary design complete: November 2024;
- Construction start: December 2024; and
- Commissioning complete: November 2025.

5.7.2 Footscray West Zone Substation Transformer, Switchgear and Relay Condition Risk

Identified need

The condition of the 66/22 kV transformers, 22 kV switchgear, protection relays and other equipment within FW is deteriorating. JEN has assessed there is now an unacceptable risk of asset failure, with significant consequences for staff safety, and the reliability of electricity supply to customers within the supply area. While there is a need to remove these assets from service, there also remains a need to continue to supply electricity to customers within the area supplied by these assets.

The most urgent concern is the evidence of escalating partial discharges (**PD**) from the switchgear and the threat this poses to staff safety and customer supply reliability. Removing the aged switchgear from service is a priority task given the risk will increase further over time. A further concern is that two of the three existing power transformers are more than 56 years old and are showing signs of accelerating condition deterioration as they approach end-of-life. The third power transformer contains toxic, carcinogenic Polychlorinated Biphenyl (**PCB**) oil. The protection systems around these assets are also deteriorating and no longer considered fit for purpose.

JEN has confirmed FW as a priority for investment based on two key needs:

- Protecting power sector workers and members of the public from harm caused by unplanned equipment failure (safety); and,
- Maintaining a reliable power supply to the residences and businesses that are dependent on the power supply from this zone substation (reliability).

RIT-D status

The final project assessment report (**FPAR**) for this project was included as part of our 2020 DAPR and Jemena still wishes to proceed with this project to address the identified need. Further, Jemena considers there has been a material change in circumstances for this project because the identified need has been expanded to also address the transformer condition risk and the preferred option identified in the final project assessment report (switchboard replacement) is no longer the preferred option.

Jemena considers all three limbs of clause 5.17.4(t) of the NER have been met and has therefore opted to reapply the RIT-D for this project to ensure it is consistent with the NER requirement and is in the best interests of our customers.

On 26 October 2022, Jemena republished the RIT-D Stage 2 Draft Project Assessment report for consultation. The report presents a detailed assessment of all options to address the identified need. This report assesses possible non-network options and any combination of non-network options to address the identified risks. Submissions for this RIT-D Stage 2 ended on 16 December 2022. Jemena did not receive any submissions on this DPAR, and subsequently, the Final Project Assessment Report (FPAR) for this RIT-D project was published on 10 May 2023.

Options considered in RIT-D

The credible network options and the net economic benefits that were assessed to alleviate the identified needs:

- Option 1 – Base case "Do Nothing", i.e., run assets to failure;
- Option 2 – Replace one switchboard, one transformer and their relays at FW;
- Option 3 – Replace two switchboards, two transformers and their relays at FW; and
- Option 4 – Replace all three switchboards, three transformers and their relays at FW.

Each network option has two variants:

- Option 'a' – In-situ: replace poor condition assets; new assets in the same switchyard location; and
- Option 'b' – Rebuild: retire poor condition assets; new assets established in a vacant area of the switchyard.

Project outcome

Jemena has identified that Option 4b will address the project's identified needs and is the option that maximises the net market benefits to consumers compared with all the other options.

This project is a committed project and is planned for completion by June 2025.

The estimated construction timetable is as follows:

- Primary/distribution design complete: January 2024;
- Secondary design complete: February 2024;
- Construction start: March 2024; and
- Commissioning complete: November 2025.

5.7.3 Fairfield zone substation transformer No.3 condition and 4th bus

Identified need

JEN's Fairfield Zone Substation (**FF**), located at the corner of Station St and McGregor St, supplies approximately 6,756 JEN customers and 3,664 CitiPower customers (predominantly residential) at 6.6 kV in Fairfield and Alphington in the JEN supply area, and parts of Thornbury in the CitiPower supply area. The zone substation is supplied by three 22 kV subtransmission lines that originate from AusNet Services' Brunswick Terminal Station (**BTS**).

The condition of the 22/6.6 kV No.3 transformer at FF is deteriorating and is located in a position of the switchyard that inhibits further expansion of the zone substation. Jemena has assessed that this transformer has reached the end of its engineering life, and there is now an unacceptable risk of leaving this transformer remaining in-situ, with increasing consequences for the reliability of electricity supply to Jemena's customers within the supply area.

Jemena has confirmed FF as a priority for investment based on two key needs:

- to protect power sector workers and members of the public from harm caused by unplanned equipment failure or excessive noise due to deteriorating asset conditions (Health and Safety); and,
- to maintain a reliable power supply to the residences and businesses that are dependent on the power supply from this zone substation (Reliability).

RIT-D status

On 6 September 2023, Jemena published Stage 2 of the Fairfield zone substation (FF) transformer No.3 condition and 4th bus RIT-D, the Draft Project Assessment Report (DPAR). The DPAR assessed possible options for economically mitigating the supply risks at Fairfield and identified the preferred option to manage the forecast supply risk in the area as summarised below. Jemena did not receive any submissions on this DPAR, therefore the following section constitutes the Final Project Assessment Report (FPAR) for this RIT-D project.

Options considered in RIT-D

The credible network options and the net economic benefits that were assessed to options to address the identified need and continue to meet the electricity demand requirements of customers in the supply area were:

- Option 1 – Base case “Do Nothing”, i.e., run assets to failure;
- Option 2 – Replace No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF;
- Option 3 – Retire No.3 22/6.6 kV transformer and install 4th 6.6 kV bus at FF; and
- Option 4 – Replace No.3 22/6.6 kV transformer, using existing 6.6 kV buses to piggyback cables.

Project outcome

Jemena has identified that Option 2 will address the project's identified needs and is the option that maximises the net market benefits to consumers compared with all the other options.

Based on this analysis, this project is progressing to the business case stage and is planned for completion by November 2025.

The estimated construction timetable is as follows:

- Business case approval: December 2023;
- Primary design complete: September 2024;
- Secondary design complete: October 2024;
- Construction start: November 2024; and
- Commissioning complete: November 2025.

5.8 Metering and Information Technology Systems

5.8.1 Metering and information technology investments in 2023

The September forecast for metering and information technology (**IT**) capital expenditure for 2023 is 15.8 $million for non-network IT projects. This includes:

- Costs associated with SCADA and network control that exist at the corporate office side of gateway devices (routers, bridges etc.). For example, this would include costs associated with SCADA master systems/control room and directly related equipment;
- IT and communications expenditure related to management, dispatching and coordination, etc. of network work crews (e.g. phones, radios etc.);
- Any common costs shared between the SCADA and network control expenditure and IT and communications expenditure categories with no dominant driver related to either of these expenditure categories. For example, a dedicated communications link used for both corporate office communications and network data communications with no dominant driver for incurring the expenditure attributable to either expenditure category should be reported as IT and communications expenditure; and
- Major system upgrades for the Advanced Metering Infrastructure (**AMI**) meter and Advanced Distribution Management System (ADMS) to cater to the Voltage Var Control (VVC) and Future Network program of works;

- Improvements to the design, estimate, build, and closeout processes for new construction and system maintenance to ensure correct 'as-built' data is reflected in the Geospatial Information System (**GIS**) and SAP ERP;
- Continuation of work on the implementation of five-minute meter reading and global settlement compliance requirements with strengthening the AMI communication network by rolling out additional Access Points;
- Investments across a range of cyber-security tools and defences to counter the ever-increasing threat of cyber-attacks; and
- Lifecycle growth and replacement projects for IT applications systems and infrastructure to maintain the security and availability of systems, including:
    - — Application upgrades (version updates, patching, activating additional functionality);
    - — Platforms and processing (cloud, servers, data storage and backup, Operating Systems, database management systems);
    - — End user services (PCs, laptops, productivity tools, field mobility equipment such as tablets, and smartphones); and
    - — Organic growth as the market and business grows.

The 2021-2026 regulatory determination approved $131.7 million (nominal $) for IT capital expenditure over the regulatory control period.

The actual and forecast annual IT capital expenditure for 2023 is shown in Table 5-14. Actuals for 2021 and 2022 are drawn from the annual RIN reporting and 2023 amounts include actuals to date as at September 2023 and forecasts projected for the remainder of 2023.

The forecasts for 2023-2026 are drawn from the EDPR regulatory proposal for the regulatory period 2021-26.

Table 5-13: IT Capital Expenditure Actuals and Forecasts 2021-2026

	Actual / Forecast Expenditure ($ millions, nominal)						
	Actuals			Forecast			
	2020	2021	2022	2023[28]	2024	2025	2026[29]
Non-network IT Capital Expenditure	18.6	27.5	18.7	15.8	17.2	19.6	7.8

There is a variation in 2023 forecast capital expenditures compared to the submission primarily due to:

- Replanning of key projects such as ERP migration to SAP S4, Future Network and NEM reforms for later in the regulatory period.
- Significant platform lifecycle becoming operational expenditures rather than capital expenditures since their migration to cloud infrastructure
- The increasing uptake of subscription-based services and "Software as a Service", moving significant implementation costs from capex to opex under the International Financial Reporting Standard (IFRS) rules.

Key items included in the IT Capital Expenditure forecast include:

- Advanced Distribution Management System (ADMS) projects - A major replacement project was completed to replace core systems in 2020. In 2023 further capability will be enabled through the trialling of Volt-Var Control functionality to support the Future Grid Strategy. Future periods will see lifecycle upgrades and maintenance of the system.
- Projects within our Future Network initiatives are included in the forecast with most of the delivery occurring in the current regulatory control period. These projects prepare for the continued adoption and integration of CER across the distribution network.

[28] Forecast figures are Actuals (Sep Year To Date) and forecast for remainder of 2023

[29] 2026 figures only covered half of the calendar year in the regulatory period, however to get a full year view we have multiplied the half year figures by 2

- SAP migration project to ensure that the Jemena Enterprise Resource Planning (ERP) system continues to be effectively supported and maintained. The ERP is a critical IT system that is necessary for the safe, secure and reliable operation of Jemena's energy networks as well as the efficient operation of the broader organisation.
- Data Warehouse and Business Intelligence Recurrent Step Change: JEN will update the Data Warehouse and BI platforms and reporting tools through lifecycle upgrades and replace and upgrade the hardware platforms and management tools as they fail due to similar procedures as are undertaken for the other corporate applications.
- To unlock the full potential of the strategic change initiative initiated by the Foundation program which was successfully delivered in April 2023, we are proceeding with the Customer Experience Transformation Program in 2024. The primary goal of the Customer Experience Transformation Program is to replace our legacy customer portals such as the Electricity Distribution Portal (EDP) and Customer Outlook Portal on the foundational C4C platform delivered by the cX uplift program in CY 23. Furthermore, we will explore additional opportunities, including the potential integration with our contact centre telephony system (Genesys).

5.8.2 Metering and information technology investment plan 2022 to 2027

The metering and IT program of work for 2022-2027 is designed to:

- Maintain the provision of services to customers;
- Deliver new capabilities that are aligned to customer expectations, market trends and changing industry focus and enablers of JEN's Asset Strategy;
- Improve existing capabilities, minimise risk and drive efficiencies;
- Respond to business needs to implement capabilities in response to regulatory obligations; and
- Defend against growing risks associated with cyber attacks.

The major projects planned for the 2022-2027 period are listed in Table 5-14 and represent a mix of replacement, compliance and new capability projects.

Table 5-14: Metering and IT investment summary 2021-2027

Project	Investment Description
Customer Experience Hub	Improving the capability of the underlying system to improve the customer and employee experience by developing a new, unified, responsive customer portal, with relevant integrations that will allow customers to self-serve, and reduce the manual load on employees. This initiative is also designed to build a single view of customers to consolidate data into one place and ensure that employees can quickly and efficiently access it.
Outage Management and Advanced Distribution Management System (ADMS)	In 2020, the JEN SCADA and Outage Management Systems were replaced due to their end-of-life condition. The current period will focus on the deployment and embedment of the Advanced Distribution Management (**ADMS**) capability of the new system in alignment with the JEN Future Grid Strategy including Fault Location Isolation and Restoration (**FLISR**) and Volt-Var capability. The SCADA/ADMS system will also undergo maintenance upgrades as required to maintain the condition.

Project	Investment Description
Business Intelligence and Data Warehouse Replacement	Business Intelligence and Data Warehouse technologies have been upgraded in the last Regulatory period. It has extended the capability to leverage the AMI data to improve energy distribution services through analytics and decision support information. The Data Warehouse is also being extended to all of JEN's data to underpin business analytics. These services will be maintained and built upon in the current EDPR period to enable reporting on five-minute meter readings and further support business analytics, including in the space of demand management and advanced metering.
Document and Records Management	Archiving and decommissioning of obsolete data and tools.
Geospatial Information Systems	Improved capability and safety measures with the addition of new tools and consolidation of information through integration with systems as sources for asset and image data. In 2020 the GIS integration with the Advanced Distribution Management System was enhanced through the addition of LV to the ADMS model. This integration will be maintained and adapted for the requirements of the JEN Future Network program throughout the period. GIS services dependencies upon the deprecated FieldSmart platform for Asset Inspections will transition to a supportable platform. The GIS mobility platform will continue to be maintained and adapted to meet the business requirements of mobility projects throughout the period.
Corporate and Field Mobility	New capability that provides devices, network communications and integration to IT systems to support the provision of services to customers. These capabilities will be maintained and built upon in the current EDPR period.
Desktop/Laptop Standard Operating Environment Replacement	The lifecycle replacement of the devices and standard operating environment at the end of their economic life balancing security risk mitigation, end of technical life, wear-and-tear/damage and obsolescence.
Communications and Network Services	Lifecycle replacement of network devices and communications equipment.
Data Storage - SAN Replacement	Lifecycle systems replacement at the end of economic life
IT Infrastructure - Asset Lifecycle Projects	Complete the standardisation and consolidation of current capability through largely the replacement and upgrades of platforms to drive down the Total Cost of Ownership and complete the move to virtualised infrastructure.
Cyber Security	The Cyber Security program addresses both the adoption of new tools and defences and the maintenance of existing systems and mechanisms to protect Jemena's digital environment from the growing threat of cyber attack
Provision to Extend, Remediate and Change	Meet demand and plans for greater adoption of existing IT systems. Improve existing services to be more efficient. Remediate systems to ensure sustainable performance standards. Respond to continuous external changes made necessary by the market and business environment.
Provision for Growth	To meet market and business growth for software licences and capacity growth.

Project	Investment Description
Notable Regulatory and Compliance Projects	5MS/GS • On 28 November 2017, the AEMC made a final rule to change the settlement period for the electricity spot price from thirty minutes to five minutes. • Customer Switching (CS) The process to guarantee that a Customer can switch retailers within 2 business days • MSDR The MSATS Standing Data Review (**MSDR**) provided an opportunity to ensure MSATS Standing Data reflects the needs of the market by standardising the data and ensuring that the data is complete, accurate and useful. These changes also enable market participants to provide improved outcomes for electricity consumers NEM reform initiatives: The Australian Energy Market Operator (AEMO), together with industries, is delivering a number of the Energy Security Board's (ESB) Post 2025 and other energy market reforms. These reforms provide for changes to key elements of the market design, to facilitate a transition towards a modern energy system capable of meeting the evolving wants and needs of consumers, as well as enable the continued provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least-cost.

5.8.3 Advanced metering infrastructure

Advanced metering infrastructure (**AMI**) is an integrated system of smart meters, communications networks, and data management systems that enable two-way communication between JEN and smart meters at our customers' premises.

The Victorian Government mandated a full roll-out of AMI to small business and residential customers in 2006. By 2014, Jemena had deployed smart meters to 98% of our residential and business customers consuming up to 160 megawatt-hours per year.

The primary aim of the AMI project was to enable remote capabilities such as meter data collection, supply energisation, de-energisation, and meter re-configuration, and allow customers to make choices about how much energy they use by allowing them to access accurate real-time information about their electricity consumption. JEN has taken steps to steadily unlock other network and customer benefits that AMI offers by linking AMI to the Distribution Management System and establishing an Advanced Data Analytics platform.

Examples of applications that have been established include:

- Real-time reports of supply outage and restoration, enabling faster fault detection and restoration;
- Customer supply quality monitoring, enabling proactive detection and rectification of degraded service;
- Direct or indirect load control to support demand-side responses;
- Improved low-voltage asset utilisation through the identification and optimisation of phase loading and load projection;
- Electricity theft detection; and

- Develop intelligence and insight for more efficient and effective network management and operation.

JEN is currently exploring further applications of AMI including dynamic network voltage management to strategically respond to the network voltage challenges associated with increasing solar PV and other forms of CER penetration in the coming years. The use of AMI data will also include LV visualisation and modelling tools for the desktop investigation of customer complaints and network performance issues.

JEN is developing a Dynamic Voltage Management (DVM) trial system in 2023. The DVM shall use near real-time (15 min delivery interval) AMI voltage data as the feedback signal for the closed-loop control of zone substation transformer voltages. A trial of the DVM trial system in two zone substations is expected to commence in early 2024.

5.8.4 Applications of advanced metering infrastructure

Specific applications of the AMI are provided below in accordance with the requirements of clause 19.4.1(e) of the EDCoP:

(a) Life support customers

Life support customers are tagged in JEN's OMS.

When supply interruption occurs, Jemena's control centre is informed via several means:

14. High-voltage feeder interruptions are monitored by SCADA;
15. Distribution substation or single premises interruptions are informed through the 'last gasp' alarms generated by AMI into the OMS; and
16. Customer calls.

In all cases, the control centre will have a clear view of how many life support customers have experienced unplanned outages at any instant in time. Life support customers, who have provided their mobile phone numbers, will receive tailored SMS messages to support them during an unplanned outage (e.g. reminder to call 000 in an emergency). JEN's customer services team is on hand to contact these life support customers for prolonged outages and offer support.

(b) Network planning and demand-side response initiatives

JEN currently uses the data from the AMI meters for the following network planning applications:

- Determine the actual and forecast loading on our distribution substations and LV network. This information forms part of our network augmentation capital expenditure to address any forecast thermal loading and voltage constraints. In determining the optimal solution, JEN also uses the AMI meter data to confirm the voltage profiles comply with the EDCoP;
- The forecast loading (minimum and maximum demand) on our distribution substations and LV network is used to assess CER and customer load connections;
- General network planning for subtransmission lines, zone substations and HV feeders to determine the network loading that is required for assessing the optimal transfer capability and asset utilisation;
- Manage supply quality issues raised by our customers; and
- To optimise our investment portfolio between distribution substation replacement and augmentation programs, such as determining whether the end-of-life transformer needs to be replaced based on the AMI data.

AMI data has been used in implementing several demand-side initiatives such as providing near real-time status to the participating customers in the residential demand response (**DR**) program (Power Changers) and also using five-minute voltage data for selected customers while implementing voltage optimisation-based DR.5.9.2

(c) Network reliability initiatives

JEN has developed an application where load information from AMI is added to load information of large consuming customers (Type 1 to Type 4) to arrive at the loading on LV distribution circuits and distribution substations. Operational measures and/or capital investments are initiated for those parts of the network where overloading is forecast to occur. Without these proactive measures, degradation of supply reliability is likely to occur during hot summer days when circuit fuses are blown or assets are damaged.

To ensure additional PV systems can have a reasonable opportunity to export surplus energy into the LV network, JEN has developed analysis and visibility capability in its advanced data analytics platform and used the insight to proactively rectify localised power quality issues (voltage rise, phase unbalance, high impedance connection).
5

(d) Quality of supply information described in Schedule 2 of the EDCoP

JEN’s AMI meters record instantaneous voltages at five-minute intervals. The data are used to generate the distribution voltage information required in accordance with the EDCoP reporting requirement in Schedule 2 (refer to our website https://jemena.com.au/electricity/network-information/network-planning for this information in an accessible format).

Samples are aggregated/averaged by substation and then by control zone. Substation averaging is completed daily so the data can be used for finer and more frequent assessment of voltage regulation. Control zone averaging is performed every three months for the previous three months at the start of each period. No attempt is made to average successive five-minute samples as this has no impact on the three-month average.

5.9 Demand Management and Embedded Generation Connection

The electricity supply industry, and in particular distribution networks, is undergoing rapid change with the evolution of new technologies that are impacting the way networks are planned, operated and maintained.

Customers are increasingly looking for flexible and cost-efficient solutions for energy consumption management. Government policy and regulatory frameworks are being formulated to respond to these technological innovations and consumer preferences and, in line with these changes, JEN's network investment objective is to provide network services that are safe, affordable and responsive to our customers' preferences, while enabling innovation and change.

Demand management aims to manage the electricity use profile on a network to minimise the cost of supplying customers while maintaining or improving customer options and service levels, and is defined by the AER[30] as:

> *"any effort by a distributor to lower or shift the demand for standard control services, including, agreements between distributors and consumers to switch off loads at certain times and the connection of small-scale 'embedded' generation reducing the demand for the power drawn from the distribution network".*

Non-network solutions that do not involve traditional network asset development (poles and wires) are broadly classified as demand management (**DM**) solutions and can include:

- Tariff offerings, such as time-of-use and critical-peak pricing;
- Demand response, where load reduction is contracted. This load reduction can be initiated by the customer, as directed by the DNSP in response to price signals or directed by a demand response service provider, or by the DNSP through direct load control of devices such as air conditioners, pool pumps, electric vehicle charging;
- Embedded generation;
- Energy storage and subsequent release at peak times, including electric vehicles fitted with vehicle-to-grid technology;
- Stand-alone power systems; and
- Energy efficiency incentive programmes.

There are three key drivers for DM program development as an alternative to augmentation works:

- **Investment flexibility** – Traditional network investments require large capital expenditure and a long-term commitment to ensure benefits are maximised. In situations where electricity demand is not increasing at the same rate as in the past, or there is uncertainty about future demand growth, DM solutions can provide incremental capacity increases and the flexibility to wait and see how the environment develops, without committing to high-cost network developments;
- **Asset development deferral** – DM solutions present an opportunity to shift the economic timing of an asset's development. Network constraints can be mitigated or managed at a reduced risk level while still delivering a favourable economic outcome for consumers; and
- **Improving network reliability** – DNSPs and their customers carry operational risks that can be quantified as the cost of EUSE. DM presents an opportunity to mitigate a portion of this power supply risk both before and during outages, thereby reducing the overall costs to consumers and the costs of operating networks. The cost-effectiveness of a DM program is driven by the attributes of the customer base DM technologies, maturity of DM services market and business processes employed, which must be efficient and react fast enough to mitigate the impacts of network outages.

[30] AER, Final Framework and Approach for the Victorian Electricity Distributors, October 2014, p113

5.9.1 Demand management objectives and strategy

JEN's objectives for demand management are to:

- Develop options and flexibility for our network and customers through the application of DM;
- Establish policies, systems and processes that support DM; and
- Where economical, resolve network supply quality and capacity constraints using DM.

JEN's strategies to deliver these objectives are to:

- Establish DM solutions as viable alternatives to traditional network investments, including:
  - Evaluating the feasibility of DM solutions as part of ongoing business-as-usual planning processes;
  - Considering a DM option earlier to manage the residual risk;
  - Facilitate DM response to achieve 'Investment Flexibility', help non-network services grow for the future and ensure uptake of a DM solution in the current market conditions;
  - Implementing DM where economically beneficial to customers; and
  - Collaborating with specialist providers and developing JEN's intellectual property.
- Support the Australian electric utility sector in the implementation of DM solutions, including:
  - Assuming a larger role in the demand management value stream and limiting reliance on specialist providers in areas of high strategic priority;
  - Developing resources, systems and processes to maximise the efficiency of Jemena's DM initiatives;
  - Supporting the development of demand management and alternative technology solutions as part of JEN's growth strategy; and
  - Build capabilities to undertake a Distribution System Operator (**DSO**) role to integrate various forms of DER to meet the needs of the customers and the network.
- Extend JEN's demand management capabilities in line with the long-term corporate strategy for the business.

5.9.2 Demand management initiatives

JEN has reviewed its demand management program and intends to focus on the following areas in 2023-2028:

- Efficient connection of micro-embedded generators;
- Manage peak demand through demand response from customers;
- Exploring the use of dynamic operating envelopes to manage residential customer electric vehicle load; and
- Explore the use of renewable embedded generation (including solar PV) and energy storage for network peak demand support.

The following demand management initiative has recently been completed for 2021-23:

- Dynamic Electric Vehicle Charging Trial.

The following demand management initiative is planned for 2024 and onwards:

- Community Batteries.

Dynamic Electric Vehicle Charging Trial

JEN led an ARENA-funded collaboration between five DNSPs and a leading EV charging installer to understand the impacts of EVs on the electricity system and consumer willingness for third-party control and to demonstrate how DNSPs can play a direct role in EV charge management.

An operating envelope is a limit that an electricity customer can import or export to the electricity distribution network before the physical or operational limits of the distribution network are breached. It essentially provides upper and lower bounds on the import or export power for either individual DER assets or a connection point.

Currently, in most cases, operating envelopes are fixed at conservative levels to account for ‘worst case’ network conditions. These ‘worst case’ conditions may only occur for a small percentage of the time, so this static approach results in limits being in place for a large percentage of time when there are no constraints on the network.

Dynamic operating envelopes (**DOE**) allow import and export limits to vary over time and location. Dynamic rather than fixed export limits could enable higher levels of energy exports from customers’ solar and battery systems by allowing higher export limits when there is more hosting capacity on the local network leading to a more effective and efficient operation and use of distribution assets.

The main objective of this DNSP-led trial was to prove the concept of managing EV charging load dynamically by sending a DOE to the charging infrastructure, with a real-time assessment of available network capacity, to accommodate more EVs without network augmentation. A small number of EVs per DNSP were included in the trial. Incentives were offered to customers to install smart EV chargers and to participate in EV charge management events. During the managed charging events, a DOE was sent to the EV charger to define the charge rate based on the current network conditions.

The trial was successful in developing, testing and implementing the capability to understand the charging behaviour of existing EV owners and the extent to which networks can manage their load to shift energy to periods of high renewable energy supply, reduce demand during periods of peak demand or low renewable energy supply and support network and wholesale constraints.

Solar Soak (**SS**) events were designed to encourage additional demand during times when the grid would have excess solar energy, such as during periods of high solar production and low demand. There were five SS events completed to investigate the increase in load on the grid and manage the impact of minimum demand while making better use of the available solar energy. Demand response (**DR**) events refer to the shifting or reducing of demand usually to support grid stability and security. As such, five DR events were initiated during the trial to understand the capability of participants to provide DR support and limit their EV charging during constrained periods.

Participants in the trial were mostly satisfied with the delivery of the events and the trial overall and were content with having their EV charging managed by another party and purchasing a smart EV charging themselves. Any implementation of the lessons learnt will need to consider the applicability for mass market EV adoption given the small scale of the trial’s cohort of participants which are likely to reflect highly engaged early adopters, those that are informed and aware of their charging behaviours and those that have other behind the meter technologies such as solar PV. Future EV owners may not be as engaged or technologically aware which may impact the effectiveness of managed charging via DR and SS events and may also impact the network differently to those within the trial.

Community Batteries

In 2024 Jemena will be deploying our first Neighbourhood (Community) Battery Energy Storage System (BESS) and will continue to explore opportunities for future investment in BESS under various funding initiatives.

The general network conditions that we may look to address with BESS are:

- Growing network demand or over-utilisation of network assets
- Above-average solar penetration, excess generation and/or solar reliability issues.

Under various funding initiatives, Jemena is deploying 4 community batteries in the Jemena Electricity Network which will be deployed in front of the meter (FTM) in different suburbs.

The size of these community batteries has been proposed as approximately 120kW/360kWh however this capacity as well as specific locations will be confirmed in early 2024.

The deployment of the Community Batteries will enable Jemena to investigate the benefits and objectives of:

- lower electricity bills;
- support more households to install rooftop solar;
- allow households who cannot install solar panels to enjoy renewable energy;
- reduce pressure on the electricity grid;
- absorb excess energy that might cause voltage spikes in the electricity grid; and
- lower emissions.

Jemena also recognises that our future network will have network-owned and non-network-owned BESS and expects in 2024 and the forward planning period to also be providing support to non-network-owned battery projects.

JEN continues the upkeep of the demand response register, allowing parties to register their interest in being notified of developments relating to distribution network planning and expansion by sending an email request to DemandManagement@jemena.com.au.

5.9.3 Demand management for network project deferral

JEN has not identified any specific network projects in the forward planning period that can be deferred through demand management. It has been assessed that all the network augmentation capex projects, especially the high-voltage feeder upgrades, will be evaluated for non-network options to determine if a non-network solution is effective and cost-efficient at that location. It is also envisaged that with the introduction of wholesale DR rules, the market will be able to offer more reliable and efficient DR services to support network limitations.

5.9.4 Customer proposals

In 2023, JEN received two connection applications for embedded generators that have a generation capacity greater than 5 MW. JEN believes this low level of connections for larger embedded generators is due to:

- The nature of the JEN network, which services the north-east of greater metropolitan Melbourne, where there is limited availability of physical space for a significantly sized embedded generator;
- Underlying weaker energy and maximum demand growth in the Victoria region; and
- A preference for smaller-scale embedded generation, particularly rooftop solar, for which the JEN network has seen an ongoing increase in installed capacity.

Notwithstanding this, JEN will continue to investigate opportunities for embedded generation (EG) projects that can reduce network investment while maximising customer benefits. Table 5-15 and Table 5-16 provide a quantitative summary of the connection enquiries and applications to connect EG systems received in 2023 under Chapter 5 of the NER.

Table 5-15: Summary of >5 MW embedded generation connections in 2023[31]

Description	Quantity (>5 MW)
Connection enquiries under NER clause 5.3A.5	3 (non-registered)
Applications to connect received under NER clause 5.3A.9	2

Table 5-16: Summary of <5 MW embedded generation connections in 2023[32]

Description	Quantity (<5 MW)
Connection enquiries under NER clause 5A.D.2	11

[31] Quantity reported is as at 1 December 2023.

[32] Quantity reported is as at 1 December 2023.

Applications to connect received under NER clause 5A.D.3	4639
Average time taken to complete Applications to Connect	Within 65 business days, all information was submitted.

5.9.5 System Strength Locational Factor

In October 2021, the AEMC made its final rule determination on efficient management of system strength on the power system. The Rule introduces a new way for system strength remediation in the NEM, allowing the embedded generators to either pay for system strength charges or self-remediation. The system strength locational factor represents the electrical distance of the embedded generation connection point to the system strength node (a location on a transmission network that AEMO declares under NER clause 5.20C.1(a)) and is used to calculate the system strength charge in accordance with the methodology in the AEMO's System Strength Impact Assessment Guidelines[33].

Under NER Schedule 5.8 (q), the system strength location factor information for each embedded generation (or generating system) in the JEN network in which the embedded generation system has elected to pay the system strength charge under clause 5.3.4B(b1) is to be included in this report.

JEN currently does not have any embedded generator in its network that has elected to pay a system strength charge for system strength remediation and will include the system strength location factor information in this report once it has an embedded generation connection that elects to pay the system strength charge.

33 Refer to AEMO | System Strength Impact Assessment Guidelines

5.10 Factors that may Materially Impact the Network

This section describes factors that may have a material impact on JEN's electricity network, including Rapid Earth Fault Current Limiters (**REFCLs**), prospective short-circuit levels (fault levels), voltage levels, power system security, quality of supply, and power system reliability and ageing and potentially unreliable assets.

5.10.1 Rapid Earth Fault Current Limiter (REFCL)

REFCLs are devices installed at zone substations designed to significantly reduce the energy dissipation of phase-to-ground faults. Since 70% of all faults are phase to ground, this device improves network reliability and provides a safer network for personnel and the general public. Another major benefit of REFCL deployment is the significant reduction in the risk of fire start ignition. This is particularly relevant to the 22 kV polyphase supplying Hazardous Bushfire Risk Areas (**HBRA**).

Coolaroo (COO) and Kalkallo (KLO) zone substations have mandated REFCLs stipulated by the Electricity Safety Act 1998 (the Act) and the Electricity Safety (Bushfire Mitigation) Regulations 2013 (the Regulations), which requires a higher level of REFCL performance based on a prescribed 'Required Capacity'. This includes limiting fault current on feeders to 0.5 A or less in the event of a phase-to-ground fault on a polyphase electric line with a nominal voltage between 1 kV and 22 kV. The 'Required Capacity' for those REFCLs covered by the Act and Regulations is maintained by limiting the zero-sequence capacitive current (Ico) contribution of HV cables and overhead conductors on each applicable zone substation bus.

REFCL Requirement at Coolaroo and Kalkallo Zone Substation Supply Areas

To meet its obligation under the Act and the Regulations, JEN installed and commissioned two REFCLs at COO in 2023, and in accordance with its approved exemption applications[34],

- Reconfigured feeders to ensure HV overhead lines in the HBRA are supplied from COO No.1 22 kV bus, with the remaining feeders supplied from COO No.2 22 kV bus;
- Ensured the REFCL protecting the feeders of COO No.1 22 kV bus enables Jemena to demonstrate compliance with the 'Required Capacity'. This bus is referred to as the COO 'High-Performance Bus'. The REFCL protecting the feeders of COO No.2 22 kV bus is referred to as the COO 'Low-Performance Bus';

Transferred the HV overhead sections of JEN's KLO feeders to the COO High-Performance Bus; Engaged Commonwealth Scientific and Industrial Research Organisation (**CSIRO**) to assess the bushfire risk associated with those sections of the COO 22 kV feeder network that remain supplied by the COO Low-Performance Bus or KLO zone substation (as a non-REFCL zone substation), and apply for exemptions from the Act and the Regulations based on proposed remedial works.

REFCL at Sydenham Zone Substation

To limit the impact of earth fault currents acting as an ignition source in high-risk bushfire areas, JEN installed a REFCL at Sydenham Zone Substation (SHM) in 2017[35].

REFCL at Sunbury Zone Substation (SBY)

Installation of a REFCL at Sunbury Zone Substation (SBY) has been deferred beyond the forward planning period.

Forecasting REFCL limitations

Each year, JEN forecasts the Ico for each of its REFCL zone substation buses, based on the forecast total length of HV overhead line and underground cable installed per phase across each feeder, and the capacitance of each type of line and cable. The present calculated value is compared with the measured value from the REFCL control

[34] JEN lodged its exemption applications to both the ESV and DEECA for a solution to cover REFCL requirements for COO and KLO, and the exemptions from the Act and the Regulations were granted in November 2020.

[35] REFCL is not mandated at SHM zone substation. JEN has installed a REFCL at SHM to limit short circuit levels that occur during a fault, reducing the likelihood of a fault igniting a bushfire.

system, and a scaling factor is applied to the calculated values to address any difference. Where a limitation is identified in the forecast, a least-cost solution is proposed to maintain the REFCL performance within the 'Required Capacity'.

Table 5-17 shows the forecast Ico for each of JEN's REFCLs and identifies the forecast limitations.

Table 5-17: Forecast limitations on REFCL performance (Ico Amperes)

REFCL	Rating	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
COO Bus No.1	**120**	108	111	115	118	**122**	**125**	**129**	**132**	**135**	**139**
COO Bus No.2	**300**	259	276	287	299	**311**	**323**	**336**	**350**	**364**	**378**
SHM	**320**	**330**	**344**	**352**	**359**	**363**	**368**	**373**	**377**	**382**	**386**

The REFCL limitations identified include:

- COO Bus No.1 from 2028 – the proposed network solution is to transfer some underground sections of feeders COO11 and COO12 to the surrounding feeder network.
- COO Bus No.2 from 2029 – the proposed network solution is to transfer parts of feeders COO22 and COO24 to the ST zone substation by establishing a new feeder at ST.
- SHM from 2024 – the proposed network solutions are to either transfer parts of SHM feeders to SBY and a new zone substation in Plumpton or to install a second base-performance REFCL at SHM.

5.10.2 Fault levels

Electrical assets, including switchgear, overhead lines and transformers, have a maximum allowable current rating. When this limit is exceeded under short circuit fault conditions, the assets will be exposed to catastrophic damage and will need to be replaced.

Jemena conducts fault level studies to estimate the prospective short-circuit level throughout the network to ensure it is within the capability of network assets and the limits set out in the NER and EDCoP. Where the regulatory requirements differ, JEN plans its network to the most onerous standard. The estimated maximum prospective short-circuit levels are included in the subsections of Section 5.11 for each of the JEN-owned zone substations.

Table 5-18 shows the maximum allowable short-circuit fault levels (by voltage), as specified in the EDCoP at connection points.

Table 5-18: Distribution System Fault Levels

Voltage Level (kV)	System Fault Level (MVA)	Short Circuit Level (kA)
66	2500	21.9
22	500	13.1
11	350	18.4
6.6	250	21.9
<1	36	50

Fault levels are determined by network impedances and power flow. Increasing fault levels on the JEN network are caused by:

- Network changes at the transmission level, which results in transmission connection point fault level changes that cascade down to the distribution network;
- Changes to the level of embedded generation; and

- Network changes within our distribution system, such as the installed transformer capacity. For example, a 22 kV network supplied from two 66/22 kV transformers, will experience a higher fault if a third 66/22 kV transformer is installed, due to the change in network impedance.

To mitigate against higher fault levels, JEN would typically operate with open bus ties on networks where the fault levels would otherwise exceed limits. Alternatively, the addition of network impedance, such as installing series reactors, will reduce fault levels.

AW, BD and EP zone substations comprise four 66/22 kV transformers and have their bus ties opened to ensure fault levels remain within the EDCoP limits.

There are no ‘single’ projects over $2.0 million within the forward planning work program that are driven by fault-level issues.

5.10.3 Voltage levels

All customer equipment requires the supply voltage to remain within allowable bounds to function correctly. JEN is required to maintain customer voltages within specified thresholds, which are presented in Table 3-5. JEN network voltages are affected by:

- **Generation exports** – In recent years JEN has been investigating voltage control challenges posed by exports from the increasing penetration of embedded generation systems. In particular, rooftop solar PV systems raise the network voltage at their point of connection to the supply network. Accommodating these voltage rises from a network planning perspective is not trivial, due to the intermittent nature of solar PV generation and the design of the distribution network. With the completion of the smart meter rollout program, JEN can now monitor the amount of solar PV net generation, as well as the connection point voltages through the smart meter infrastructure. Analysis of the data is ongoing and JEN is developing proactive measures to address voltage rise issues that are impacting customer supply voltages.
- **Impedance of transmission and distribution network equipment** – higher impedance equipment, such as long subtransmission or distribution feeders exhibit a higher voltage drop, or voltage rise if there is generation, across the plant, which is more pronounced during periods of high demand or high generation.
- **Load** – as the demand on the network increases, the network voltages will tend to decrease. Conversely, as the demand on the network decreases, the network voltages will tend to rise.
- **Reactive power demand** – reactive power is power that is not consumed, but rather, supports network voltages. A customer with a low power factor has a higher reactive power demand. JEN installs capacitors at its zone substations to supply reactive power demand and support network voltages.
- **REFCL condition** – REFCL is an enhanced earth fault detection using an arc suppression coil, normally installed in zone substations. The REFCL has the potential to reduce the risk of fire starts from an earth fault. It reduces the voltage on the faulted phase to a very low value almost instantaneously. However, by doing so, it raises the voltage on the healthy phases by 73% (nominally from 12.7 kV to 22 kV).

  Customers directly connected to high voltage of REFCL protected networks may need to take action in response to REFCL deployment. The REFCL deployment at a zone substation generally impacts the assets connected to its high voltage (22 kV) feeders. However, in emergency or system abnormal situations, it may become necessary to transfer parts of a feeder from an adjacent non-REFCL-protected network to a REFCL-protected network. Existing and new HV customers connected to non-REFCL-protected feeders listed below may experience a REFCL condition during contingent events.

Table 5-19: Feeders that may experience a REFCL condition

Year	Possible REFCL conditions
REFCL Zone Substation	SHM and COO[36]
Non-REFCL-protected feeders which may experience a REFCL condition	SBY-32, SA-6, SA-10, SA-12, MLN-21, AW-9, SBY-24, ST-12, ST-32, ST-33, ST-22

To maintain voltages within the allowable range at zone substations and on HV feeders, JEN will:

- Operate the on-load tap changers (OLTC) at the zone substation or the transmission connection point transformers to manage the customer side voltage, noting that JEN attempts to optimise the set point for all transformer OLTCs based on the surrounding network characteristics;
- Add reactive support in the form of capacitor banks or reactors, either at zone substations or on pole tops; and
- Install voltage regulators near the end of long feeders that have voltage issues.

To maintain voltages within the allowable range on the LV network, JEN will undertake one or more of the following corrective actions on an as-needs basis:

- Adjust distribution transformer off-load tap changer;
- Upgrade distribution substations;
- Balance load across LV circuits;
- Reconfigure LV circuits or
- Re-conductor LV circuits.

JEN is currently exploring further applications of AMI including DVM to strategically respond to the network voltage challenges associated with increasing solar PV and other forms of CER penetration in the forward planning period. A trial of the technology is currently underway at AW and CS, and this trial is expected to be completed in 2024 with the anticipation of a broader rollout across the network.

5.10.4 Power system security

JEN is registered with AEMO as a DNSP in the NEM and holds an electricity distribution licence in Victoria. This places specific obligations on JEN to plan, operate and maintain its network in accordance with relevant statutory codes and rules. AEMO has primary responsibility for system security under Clause 4.3.1 of the NER[37]. However, there is a general obligation on DNSPs under Clause 4.3.4(a) of the NER to respond to AEMO's direction by developing and implementing solutions to mitigate power system security risks at AEMO's direction.

AEMO is responsible for dispatching generation in the NEM to maintain supply-demand balance and historically networks are responsible for disconnecting load at transmission terminal stations in response to under-frequency events. This approach to setting responsibilities made sense when most generation was large, centralised, controllable and connected to the transmission networks, and when transmission points of connection were always net loads.

With significant growth in distributed embedded generation, much of which is uncontrolled Distributed Solar PV (DPV), solutions at the transmission level are becoming increasingly ineffective, as transmission points of connection (at times) transition from net loads to net generators.

AEMO expects net minimum demand in Victoria to fall below its minimum acceptable operating threshold by the end of 2024. This poses challenges for AEMO in its role in maintaining power system security, for two key stability elements and their consequences. Actions are required to redress both of these emerging power system security

36 Note that some sections of KLO-22 will be transferred to COO-11 in 2022.

37 National Electricity Rules (NER) Version 203, AEMC, 9th October 2023.

needs. These actions are needed in the form of granular solutions at the distribution level to redress the associated power system security issues that are forecast in Victoria over the coming years.

As such, in August 2021, AEMO issued a directive[38] to JEN and other Victorian network businesses, asking network service providers to identify and implement measures to restore power system security from the challenges caused by increasing levels of uncontrolled DPV within their respective networks. The two key stability elements of concern to AEMO are supply-demand balance (minimum demand), and under-frequency load shedding (**UFLS**) scheme, and are detailed below.

Supply-demand balance

The supply-demand balance system security challenge occurs when the net minimum system demand (as seen at the transmission level) falls below a level that will compromise the stability of the overall power system. It manifests as an oversupply of DPV generation that cannot be controlled by AEMO, causing the power system to collapse due to the system frequency rising well above 50Hz due to generation exceeding demand. This tends to follow a critical contingency event such as the loss of an interconnector, eventually emerging into a system-normal event as DPV continues to grow.

The need for an embedded generation backstop capability is focussed on those embedded generating units that AEMO does not have visibility of control over, in particular DPV systems. To maintain system security, AEMO must maintain a supply-demand balance across the NEM at all times.

Department of Energy, Environment and Climate Action, Victoria (DEECA) has a preference for DNSPs to implement DPV backstop capability to curtail or trip DPV systems. DEECA requires this option to provide emergency curtailment capabilities for all new and upgraded DPV systems through the ability to monitor, control (or disconnect) in a 15 to 30-minute response time, and restore these DPV systems remotely, at the request of AEMO, delivered in two stages:

- Stage 1: > 200kVA which came into effect on 25 October 2023;
- Stage 2: ≤ 200kVA by no later than 1 July 2024

DPV Backstop mandate would be implemented via an Order made by the Minister for Energy and Resources under Section 33AB of the Electricity Industry Act 2000 as a new licence condition(s) on distribution businesses.

UFLS

UFLS is an existing load-shedding control scheme triggered upon a loss of generation event that becomes ineffective due to the presence of reverse power flows from DPV, causing the power system to collapse due to the system frequency falling well below 50Hz due to demand exceeding generation.

UFLS schemes were traditionally designed on the assumption that they would shed blocks of load based on one-way power flow. With the uptake of DPV, there is an increasing risk of the load-shed blocks being net negative (i.e., generation) sources because of reverse power flows. The effect of shedding such blocks can cause a state-wide collapse of the power system from under-frequency.

NER schedule S5.1.10.1 and clause 4.3.1(k) require NSPs to ensure that 60% of the underlying load is under the control of the UFLS scheme, as measured by the net demand at transmission connection points. This will become increasingly difficult as DPV growth continues and the net demand as measured by the UFLS scheme reduces. Load blocks with reverse power flow and the reduced numbers of available load blocks are a threat to the effectiveness of the UFLS scheme in responding to a widespread loss of transmission generation sources.

AEMO requires DNSPs to implement a distributed, granular UFLS control scheme that involves the automatic disconnection of dynamic load blocks through the ability to apply settings remotely (i.e., frequency and trip time), monitor, arming and disarming of UFLS, disconnect (in 0.2-0.5s response time), and restore load within the

[38] AEMO letter to JEN dated 9 August 2021.

distribution network. In May 2023, AEMO published its 'Victoria: UFLS load assessment update' report outlining the emerging issues and recommendations for actions for Victoria[39].

5.10.5 Quality of supply

JEN is required to comply with the requirements in Section 20 of the EDCoP and Schedule S5.1a of the NER, as discussed in Section 3.5.

Poor quality of supply can lead to:

- Increased losses, in the case of unbalance and harmonics; and
- Customer dissatisfaction in the case of voltage variations and flicker, which can result in tripping of sensitive electronic equipment and lighting flicker.

JEN monitors the quality of supply from PQ meters installed throughout its network, at both the zone substation level, and at the far end of one, typically the longest, high-voltage distribution feeder emanating from each zone substation. Where the quality of supply falls outside allowable limits, or when assessing the impact of new connections, Jemena will carry out system studies investigating power quality, and initiate projects to improve power quality as needed.

There are no single projects over $2.0 million within the forward planning work program that are driven by power quality issues.

5.10.6 Power system reliability

Power system reliability refers to the capacity of the power system to deliver all customer loads. Given that JEN plans its network to ensure it can meet the forecast demand, aged and deteriorating assets, which are prone to failure, are the primary cause of low power system reliability.

Asset failures may reduce service reliability and until the asset is replaced, the security of these services is also reduced, as further failures may result in more widespread service disruptions.

JEN aims to reduce the impact of ageing and unreliable assets through its asset management approach, as described in Section 2.2.

In the forward planning period, JEN has several planned network augmentation projects over $2.0 million, which include replacing unreliable assets based on condition-based assessments. Refer to Section 5.11 and Section 5.12 for further details on these projects.

[39] 2023-05-25-vic-ufls-2022-review.pdf (aemo.com.au)

5.11 Zone Substation and HV Feeder Limitations

Refer to our digital DAPR map for information about each zone substation and HV feeder risk assessment.

This section presents information about zone substation and feeder ratings (including potential and proposed risk mitigation options), forecast loading levels for the forward planning period (2024-2028) and the annualised cost of expected unserved energy for identified zone substation limitations. It also includes recently completed projects and network developments that JEN is committed to deliver within the forward planning period.

5.11.1 Zone substation import limitations

Each of the identified zone substation limitations and network impacts incorporates the following annualised information for the forward planning period:

- A figure showing the 10% probability of exceedance (**POE**) and 50% POE maximum demand (**MD**) forecasts, compared with the system normal (N secure) import rating and N-1 import rating. The maximum demand forecasts and zone substation import ratings presented in these figures are for each zone substation's peak loading period (summer or winter);
- The 10% POE maximum demand (MVA) during each zone substation's peak demand period for existing and committed zone substations;
- The number of hours per year that the imported power reaches or exceeds 95% of the maximum demand;
- Power factor at maximum demand (p.u.) which is the power factor at the time of maximum demand presented in per unit of real to apparent power demand. The value presented assumes that all capacitor banks connected to that zone substation are contributing their full reactive power capability;
- The 10% POE N-1 loading (%), which is the maximum zone substation utilisation that is forecast to occur during the maximum demand period following the worst credible contingency. This loading level is presented as a percentage of the substation's N-1 import rating for the maximum demand period;
- Maximum load at risk under N-1 (MVA) which is the load that would be lost if the worst credible outage occurred at the time of maximum demand;
- Hours at risk (h) which is the number of hours where the zone substation loading is forecast to exceed the N-1 import rating in a given year and is therefore at risk of not being supplied if the worst credible outage occurs;
- The EUSE (MWh), which is the expected unserved energy associated with a network outage in a given year and the probability of that network outage occurring (see section 2.4.2.4 for more information). The EUSE is also weighted across two network loading scenarios, with 30% apportioned to risks associated with the 10% POE scenario and 70% apportioned to risks associated with the 50% POE scenario;
- The cost of EUSE ($ thousand) which is the cost of expected unserved energy in a given year (see Section 2.4.2.4 for more information);
- Embedded generation, which is the known amount of large (units above 1 MW) embedded generation connected within the zone substation supply area. Embedded generation has been excluded from the load at risk and expected unserved energy calculations; and
- Load transfer capacity, which is described in detail below.

For zone substations where a risk of USE is forecast, JEN has identified:

- A selection of mitigation options comprising both network and non-network solutions; and
- An annual maximum possible payment to non-network service providers, which is determined as the annualised capital cost for the preferred network solution, assuming a discount rate of 5.11% and an asset life of 50 years.

5.11.2 Load transfer capacity

Load transfer capacity is the amount of load that can potentially be transferred to adjacent HV feeders or zone substations under emergency outage conditions. System normal load transfer capacities are excluded because any identified transfer capacities resulting in better network supply management would typically occur as a matter of course.

Load transfer capacity will typically decrease over time due to reliance on the available capacity of adjoining zone substations and feeder lines, which decrease as network loading increases. Emergency load transfer capabilities have been excluded from the load at risk and expected unserved energy calculations, but are presented to indicate the additional support that can potentially be provided under emergency conditions.

5.11.3 Zone substation export limitations

Each of the identified zone substation peak supply export limitations and network impacts incorporate the following annualised information for the forward planning period:

- The 10% POE minimum demand (MVA) which is the zone substation’s minimum demand (or peak export if negative) for existing and committed zone substations;
- The number of hours per year that the exported power reaches or exceeds 95% of the minimum demand (or peak export if negative);
- Power factor at minimum demand (p.u.), being the power factor at the time of minimum demand (or peak export if negative) presented in per unit of real to apparent power demand. The value presented assumes that no capacitor banks connected to that zone substation are contributing reactive power;
- Maximum generation at risk under N-1 (MVA) which is the generation at risk of curtailment under 10% PoE minimum demand conditions following the worst credible contingency, relative to the zone substation’s export rating;
- The total amount of large embedded generating units (at least 1 MW) and the total amount of small embedded generating units (less than 1 MW) connected to that zone substation.

5.11.4 Feeder import limitations

Each zone substation limitation assessment also outlines the identified feeder import limitations, with utilisation levels based on 10% POE maximum demand conditions and feeder import ratings.

Identified feeder maximum demand import limitations and network impacts incorporate the following information for the forward planning period:

- The average forecast peak utilisation across feeders connected to that zone substation; and
- The forecast peak utilisation of the feeders identified as having import limitations.

For feeders where an import limitation is forecast, JEN has identified:

- A selection of mitigation options comprising both network and non-network solutions; and
- An annual maximum possible payment to non-network service providers.

5.11.5 Feeder export limitations

Each zone substation limitation assessment also outlines the identified feeder export limitations and network impacts, with utilisation levels based on peak supply conditions and feeder export ratings. Identified feeder peak supply export limitations are presented with their forecast peak utilisation.

5.12 Subtransmission Line Limitations

Refer to our digital map for information about each subtransmission loop risk assessment.

This section presents information about subtransmission line ratings and forecasts loading levels for the forward planning period (2024-2028), and the annualised cost of expected unserved energy for any identified subtransmission line limitations. Information about the potential and proposed risk mitigation options are also presented for subtransmission line limitations identified in the review process. It also includes recently completed projects and network developments that JEN is committed to deliver within the forward planning period.

5.12.1 Subtransmission line import limitations

Each of the identified subtransmission line limitations and the network impacts incorporate the following annualised information for the forward planning period:

- The 10% POE maximum demand (MVA), which is the 10% POE maximum demand on the line during the maximum demand period (summer or winter) with all loop lines in service;
- System normal loading (%), which is the 10% POE peak utilisation of the line with all loop lines in service, presented as a percentage of the line's peak period import rating for existing and committed subtransmission lines;
- Loading with a specified line out of service (O.O.S.) (%), which is the 10% POE peak utilisation of the remaining in-service lines presented as a percentage of the lines' peak period import ratings;
  - The number of hours per year that the imported power reaches or exceeds 95% of the maximum demand
- Power factor at maximum demand (p.u.), which is the power factor at the time of maximum demand presented in per unit of real to apparent power demand. The value presented assumes that all capacitor banks connected within the subtransmission loop are contributing their full reactive power capability;
- Maximum load at risk under N-1 (MVA), which is the load that would be lost if the worst credible outage occurred at the time of 10% POE;
- Hours at risk (h), which are the number of hours where the subtransmission line is forecast to exceed the N-1 import rating in a given year and is therefore at risk of not being supplied if the worst credible outage occurs;
- EUSE (MWh), which is the expected unserved energy associated with a network outage in a given year and the probability of that network outage occurring (see Section 2.4.2.4 for more information). The EUSE is also weighted across two network loading scenarios, with 30% apportioned to risks associated with the 10% POE scenario and 70% apportioned to risks associated with the 50% POE scenario;
- The cost of EUSE ($ thousand), which is the cost of expected unserved energy in a given year (see Section 2.4.2.4 for more information);
- Embedded generation, which is the amount of known large (units above 2 MW) embedded generation connected within the subtransmission loop. Embedded generation has been excluded from the load at risk and expected unserved energy calculations; and
- Load transfer capacity, which is described in detail below.

For those subtransmission lines where a risk of EUSE is forecast, JEN has identified:

- A selection of mitigation options comprising both network and non-network solutions; and
- An annual maximum possible payment to non-network service providers, which is determined as the annualised capital cost for the preferred network solution, assuming a discount rate of 5.11% and an asset life of 50 years.

5.12.2 Load transfer capacity

Load transfer capacity is the amount of load that can potentially be transferred to adjacent subtransmission lines or zone substations under emergency outage conditions. System normal load transfer capacities are excluded because any identified transfer capacities resulting in better network supply management would typically occur as a matter of course.

Load transfer capacity will typically decrease over time due to a reliance on the available capacity of adjacent subtransmission lines and zone substations, which decrease as network loading increases. Emergency load transfer capabilities have been excluded from the load at risk and expected unserved energy calculations, but are presented to indicate the additional support that can potentially be provided under emergency conditions.

5.12.3 Subtransmission line export limitations

Each of the identified subtransmission line export limitations and the network impacts incorporate the following annualised information for the forward planning period:

- The 10% POE minimum demand (MVA), which is the minimum demand (or peak export if negative) on the line during the peak supply period with all loop lines in service;
- System normal generation at risk (MVA), which is the generation at risk of curtailment under 10% PoE minimum demand conditions on the line with all loop lines in service, relative to the line’s export rating for existing and committed subtransmission lines;
- Generation at risk with a specified line out of service (O.O.S.) (MVA), being the generation at risk of curtailment under 10% PoE minimum demand conditions on the remaining in-service lines relative to the lines’ export ratings;
- The number of hours per year that the exported power reaches or exceeds 95% of the minimum demand (or peak export if negative);
- Power factor at minimum demand (p.u.), being the power factor at the time of minimum demand (or peak export if negative) presented in per unit of real to apparent power demand. The value presented assumes that no capacitor banks connected within the subtransmission loop are contributing reactive power;
- The total amount of large embedded generating units (at least 1 MW) and the total amount of small embedded generating units (less than 1 MW) connected within that subtransmission loop.

6. Appendix A: HV Feeders Utilisation

Refer to our digital DAPR[40].

[40] https://dapr.jemena.com.au/