Jemena Electricity Networks (Vic) Ltd

2019 Distribution Annual Planning Report

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2019 Distribution Annual Planning Report

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EXECUTIVE SUMMARY

Jemena is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The Jemena Electricity Networks (JEN) 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 6,500[1] kilometres of electricity distribution lines and cables, delivering approximately 4,200 GWh of energy to over 344,000 homes and businesses for a number of 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 2019 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 Jemena, and presents forecast electricity demand for the forward planning period (five year planning period from 2020 to 2024). The report also identifies existing and emerging network limitations to supplying forecast demand, and identifies and proposes credible options to alleviate or manage the identified electricity network limitations.

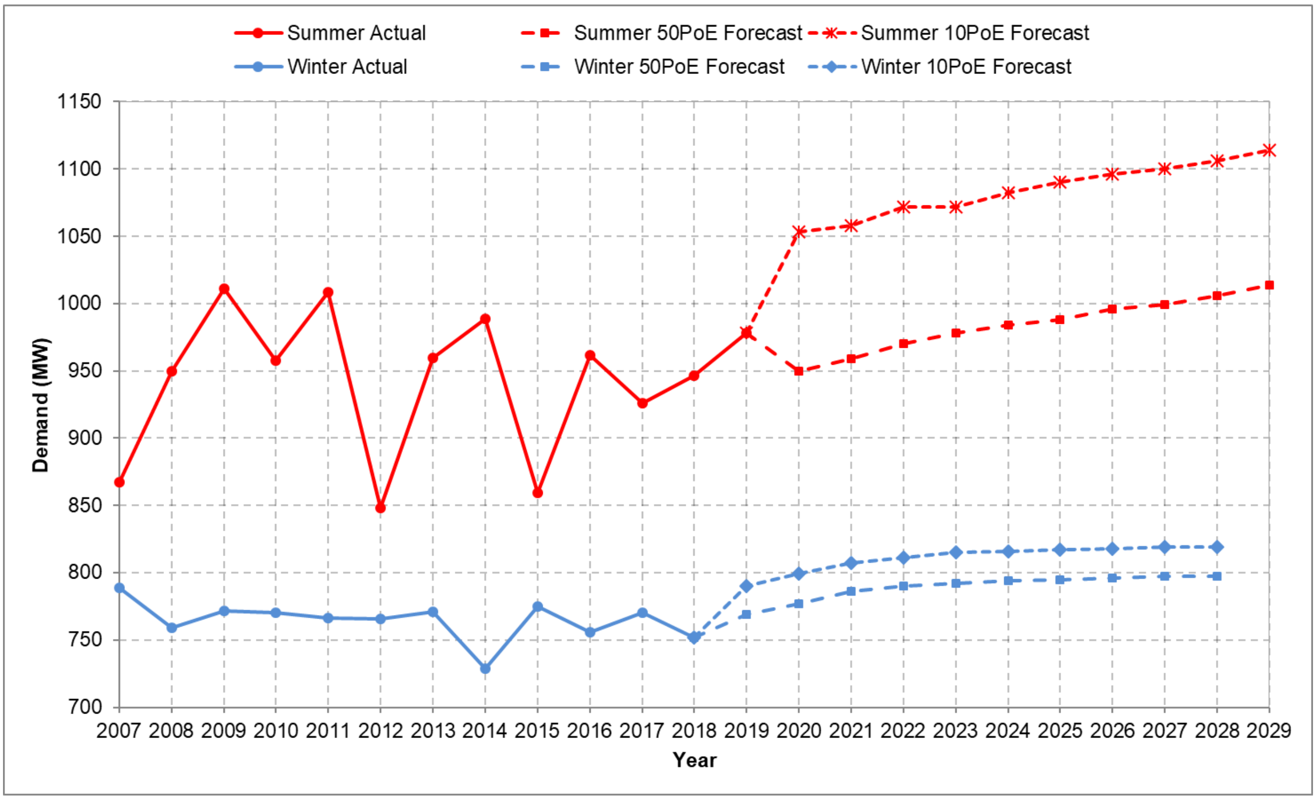
Demand growth

As a whole, the growth in demand across Jemena's electricity network is slowing, with the network-wide 50% probability of exceedance (POE) summer maximum demand forecast to grow at an average rate of just 0.79% per annum between 2019-20 and 2024-25.

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

[1] Does not include low voltage services.

Figure 1: Jemena historical and total maximum demand forecast



Despite the general slowing in demand growth 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, areas where JEN expects a strong growth is 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 recent extension of the Urban Growth Boundary, JEN expects to see continued strong growth in the areas currently supplied by Kalkallo (maximum demand forecast to grow at 11.1% per annum over the next five years), Somerton (1.3%), Sydenham (1.8%), and Coolaroo (1.5%) zone substations.

Some pockets within established inner suburbs are also experiencing strong growth as a result of amendments to the planning schemes to 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, Essendon Airport and Melbourne International Airport. As a result, JEN is forecasting high growth in maximum demand for areas currently supplied by Fairfield (2.9%), Footscray East (2.9%), Yarraville (3.8%), and North Essendon (2.5%) zone substations.

In other parts of the network, generally to the south, we are 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 Jemena's electricity network over the next five years.

Table 1: Supply area average annual maximum demand growth rate (2019-20 to 2024-25)

Season	Supply area average annual growth (2019-20 to 2024-25)			
	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	Kalkallo	Yarraville	Newport, Flemington, Somerton, Braybrook, Coolaroo, Coburg South, Sydenham, North Essendon, Footscray East, Watsonia and Fairfield	Australian Glass Manufacturer, Airport West, Broadmeadows, Melbourne Airport, Preston, Broadmeadows South, Coburg North, Essendon, Footscray West, Heidelberg, Melbourne Water, North Heidelberg, East Preston, Tullamarine, Pascoe Vale, St. Albans, Sunbury, Thomastown, Tottenham and Visy board

Network augmentation

Due to varying (and non-coincidental) maximum demand growth across the Jemena electricity network, the utilisation forecasts for a number of assets justify network augmentation. As a result, and to maintain asset utilisation at levels that support the efficient and reliable delivery of electricity to our customers, Jemena is proposing to undertake the following key network developments over $10 million within the next five years:

- Augment BTS-NS 22kV loop by November 2022;
- Install REFCL at COO and COO REFCL feeder works, and establish new Greenvale zone substation to meet the Electricity Safety (Bushfire Mitigation) Amendment Regulations 2016 by 1 May 2023; and
- Continued conversion of the East Preston supply areas from 6.6 kV to 22 kV and the retirement of East Preston zone substation by 2024.

Asset replacement

To ensure sufficient network capacity to supply customers, Jemena is responsible for managing its existing assets to ensure ongoing safety and reliability of supply. Utilising asset condition monitoring techniques, Jemena has identified that the following major projects on assets which are near the end of their useful life and pose increased public safety and reliability risks, justifying their replacement within the next five years:

- Replacement of Footscray East Zone Substation switchgear by November 2021;
- Replacement of one Broadmeadows Zone Substation transformer by November 2022;
- Replacement of Footscray West Zone Substation 22 kV switchgear and associated protection relays by November 2022;
- Replacement of the two Heidelberg Zone Substation transformers by November 2022; and
- Replacement of Coburg North Zone Substation 22 kV switchgear and associated protection relays by November 2023.

TABLE OF CONTENTS

GLOSSARY

Advanced Metering Infrastructure (AMI) meter	Also referred to as a smart meter, 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 condition, to calculate the risks of asset failures in order to guide investment decisions.
constraint	Refers to a constraint on network power transfers that affects customer service.
contingency condition (or event)	Refers to the loss or failure of part of the network. 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).
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.
energy-at-risk	The total energy at risk of not being supplied if a contingency occurs.
expected unserved energy (EUSE)	Refers to an estimate of the long-term, probability weighted, average annual energy demanded (by customers) but not supplied. The EUSE measure is transformed into an economic value, suitable for cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.
Jemena Electricity Network (JEN)	One of five licensed electricity distribution networks in Victoria, JEN is 100% owned by Jemena and services over 355,000 customers within a 950 square kilometre distribution system covering the north-west area of greater Melbourne.
limitation	Refers to a limitation on a network asset’s capacity 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 (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) or the year.
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.
megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.

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	Refers to the network's ability to transfer electricity to customers.
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 which allows for variable turns 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 of time.
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 (EDC) 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 sub transmission 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 of time.
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) which 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 22kV 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 22kV 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 a number of 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) 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.
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 / 6.6kV 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
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
ACR	Automatic Circuit Recloser
ACSR	Aluminium Conductor Steel Reinforced
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
AS/NZS	Australian Standard/New Zealand Standard
CAPEX	Capital expenditure
CBRM	Condition Based Risk Management
CC	Covered Conductors
CCT	Circuit
DAPR	Distribution Annual Planning Report
DB	Distribution Business
DC	Direct Current
DELWP	Department of Environment, Land, Water and Planning, Victoria
DM	Demand Management
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DUoS	Distribution Use of System (charges)
EDC	Victorian Electricity Distribution Code
EDPR	Electricity Distribution Price Review
E@R	Energy at Risk
ENA	Energy Networks Association
EPA	Environment Protection Authority
ERP	Enterprise Resource Planning (system)
ESV	Energy Safe Victoria
EUSE	Expected Unserved Energy
GIS	Geospatial Information System
HV	High Vvoltage
IS	Information Services
JEN	Jemena Electricity Networks (Vic) Ltd

kA	Kilo Amps
kV	Kilo Volts
LTNPQS	Long-Term National Power Quality Survey
LV	Low Vvoltage
MAIFI	Momentary Average Interruption Frequency Index
MEN	Multiple Earth Neutral
MVA	Mega Volt Ampere
MVAr	Mega Volt Ampere Reactive
MW	Mega Watt
MWh	Megawatt hour
NER	National Electricity Rules
OLTC	On Load Tap Changer
OMS	Outage Management System
OOS	Out of Service
OPEX	Operating expenditure
PQ	Power Quality
RIN	Regulatory Information Notice
REFCL	Rapid Earth Fault Current Limiter
RIT-D	Regulatory Investment Test – Distribution
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAP	Jemena’s ERP system
SCADA	Supervisory, Control and Data Acquisition
STPIS	Service Target Performance Incentive Scheme
URD	Underground Residential Development
USE	Unserved Energy
VCR	Value of Customer Reliability
ZS	Zone Substation

1. INTRODUCTION AND NETWORK OVERVIEW

1.1 PURPOSE OF THE DAPR

This 2019 Distribution Annual Planning Report (DAPR) has been prepared by Jemena 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 2020 to 2024).

The DAPR also summarises:

- The annual planning review of our electricity distribution network;
- Past performance as well as 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 support providers, 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 Jemena's customers.

1.2 JEMENA ELECTRICITY NETWORK

Jemena is the licensed electricity distributor for the north-west area of greater metropolitan Melbourne. The Jemena electricity network supplies electricity to approximately 355,000 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 Jemena electricity network 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

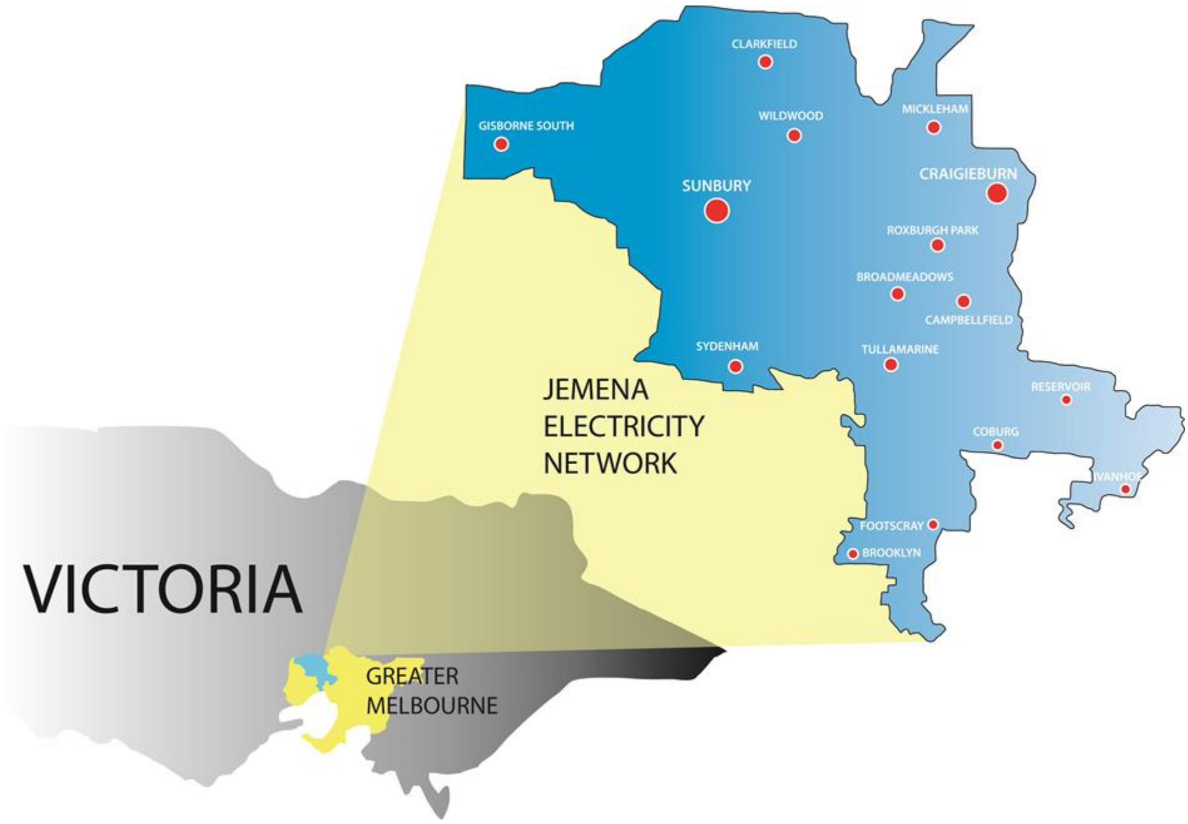


Table 1–1 presents a summary of the network's key characteristics.

Table 1–1: Network summary as at December 2018

Network characteristic	Characteristic detail
Supply area (location)	North-west metropolitan Melbourne
Supply area (square kilometre)	950
Line length (km)	6,576 (4,498 overhead and 2,078 underground)
Sub-transmission lines (number and voltage)	46 (66 kV and 22 kV)
Feeder lines (number)	221
Electricity poles (number)	102,766
Transmission connection points (location)	Brunswick, Brooklyn, Keilor, South Morang, Templestowe, Thomastown, West Melbourne
Zone substations (number)	26
Zone substations combined capacity (MVA)	1,827
Distribution transformers (number)	6,547

1.2.1 OPERATING ENVIRONMENT

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

- Changing customer preferences associated with the supply of electricity;
- Aging assets presenting technical risks;
- Significant regulatory compliance obligations;
- Changes to the physical environment in which the assets are located;
- Assets located in areas of high bushfire risk;
- Assets capable of having adverse impacts on the environment; and
- The changing nature of the key services provided by network assets with increasing embedded generation connections, and the installation of smart metering devices.

The operating environment in which Jemena's electricity network exists is changing. Rising network fault levels due to capacity expansion as well as the increased penetration of residential solar photovoltaic (PV) systems and the emergence of small scale energy storage technologies are creating operational and power quality challenges, particularly in relation to 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.

Jemena recognises that its network is aging and that, because of the operating environment changes, assets that were operating satisfactorily in the past may no longer meet safety, compliance or service performance requirements in the future. In response, Jemena continues to review its asset management strategies to ensure that assets perform at a level that meets stakeholder requirements.

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

- Improving network resilience to wind and extreme heat events;
- Implementing changes to bushfire management;
- Improving management of extreme weather events;
- Responding to government energy policy initiatives;
- Developing and applying smart network technologies;
- Developing options and flexibility for our network and customers through the application of 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 Jemena's network development process, including a summary of the annual planning review process and asset management system. It also provides a summary of the demand forecasting methodology and network planning methodologies used to identify, assess and address network limitations.

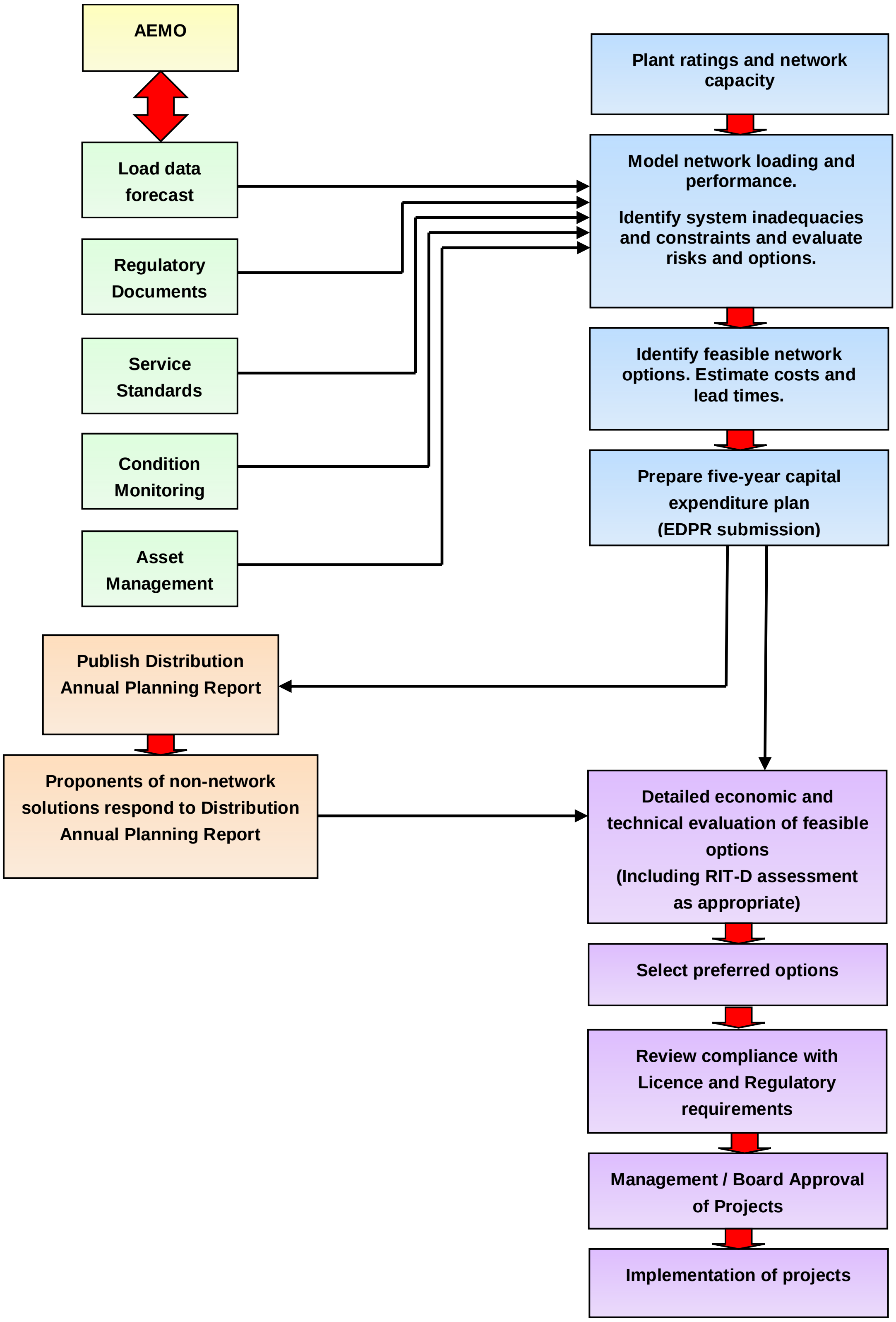
2.1 ANNUAL PLANNING REVIEW PROCESS

The Distribution Annual Planning Report (DAPR) forms part of the annual planning process undertaken by Jemena, 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 sub-transmission 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 load 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 (AEMO) is conducted in accordance with Clause 5.14.1 of the NER and Clause 3.4 of the Victorian Electricity Distribution Code (EDC).

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

Demand and energy forecasts for Jemena's connection points can be found in the 2019 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 with regard to 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 the assessment of 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 sub-transmission assets for which Jemena conducts joint planning with other DNSPs.

Table 2–1: Shared DNSP asset planning

66 kV sub-transmission loop	Shared asset owner	2019 DAPR section addressing planning outcome
KTS-SBY (WND-GSB)-SHM	Powercor	5.12.8
TSTS-HB-L-Q	CitiPower	5.12.10
TTS-NEI-NH-WT	AusNet Services (Distribution)	5.12.14

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 of the TTS-HB-L-Q sub-transmission loop requires both Jemena and CitiPower to share demand forecasts for their respective substations because the TSTS-HB 66 kV line is owned by Jemena, 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 Services (Distribution).

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

2.2 ASSET MANAGEMENT APPROACH

Jemena is committed to employing best industry asset management practice to prudently manage our assets over their total life cycle. We recognise 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. Jemena undertakes these activities in accordance with its asset management framework.

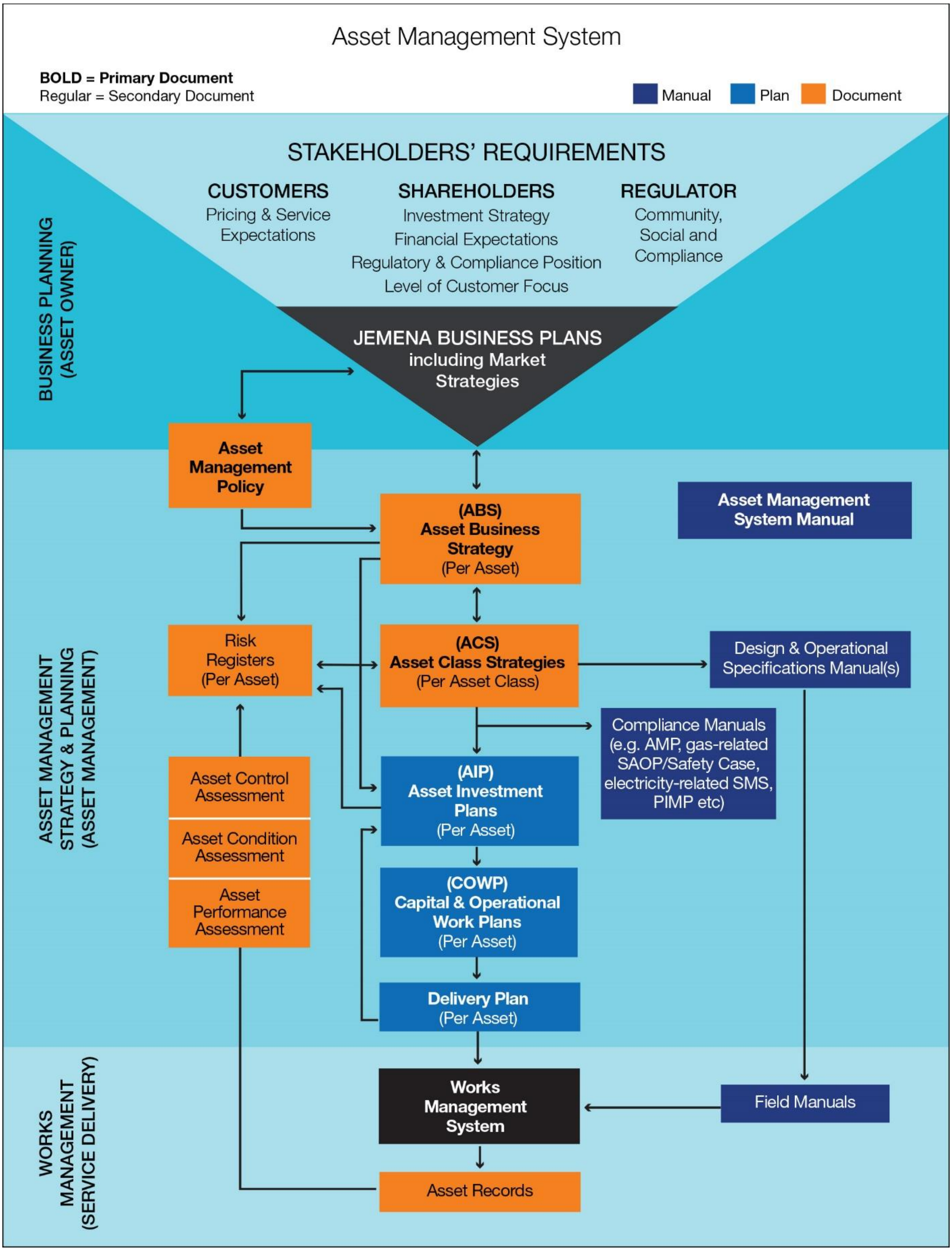
2.2.1 ASSET MANAGEMENT FRAMEWORK

Jemena's asset management framework governs the process of establishing work programs focussed 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 Jemena'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 5-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 the two-year plan of activities to be performed by Jemena in designing, constructing, operating, maintaining and supporting Jemena's electricity distribution network.

Figure 2-2 shows the document hierarchy for Jemena's asset management system. The asset management framework incorporates the asset management system's scope and boundaries in terms of Jemena'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:

- Health, safety and environment;
- Stakeholder expectations;
- Growth, demand and customer connections;
- Supply reliability and quality;
- Regulatory compliance (including technical, safety and the environment); and
- Technology.

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 is achieved;
- Ensure obligations for the connection of new customers are met; and
- Ensure management of 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 assets without compromising our employees', contractors' and public safety, as per the Jemena Health and Safety Policy;
- Apply the Jemena risk management approach to asset management activities; and
- Facilitate continuous 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 so as to eliminate workplace accidents, injuries and illnesses;
- Take a proactive approach to identifying risks that may affect the network, and manage for 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

Jemena's asset management policy directives include the development of the skills and knowledge of Jemena's people to sustain and reinforce the asset management capabilities.

Strategies to address this directive include:

- Support Jemena's staff through the development of clear policies, procedures and systems covering all asset management activities; and
- Develop high performance teams, ensuring that the competencies of our people meet the requirements of the roles by providing appropriate training to staff.

Customer

Jemena'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 specification 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.

Growth

Jemena has a corporate plan to become an influential market leader with strong customer, regulatory, stakeholder and community relationships, and deliver strong financial performance.

In the context of its asset management strategies and objective, Jemena will:

- Continue to develop plans to identify growth initiatives through innovative approaches in Asset Management services and technologies activities; and
- Develop high performance teams, ensuring that the competencies of our people meet the requirements of the roles by providing appropriate training to staff.

Performance

Jemena asset management policy directives include:

- Comply with all relevant regulatory and legislative requirements;
- Develop asset management plans that deliver the corporate objectives and business plan;
- Make best practice asset management an accepted and important part of our 'business as usual' approach and measure it against an internationally recognised asset management framework; and
- Develop and maintain asset information systems that support asset management decisions and activities throughout the asset lifecycle.

2.2.4 ASSET CLASS STRATEGIES

Jemena produces individual asset class strategies for each of its asset classes. These strategies summarise the optimal lifecycle management plan for each asset class, and consider:

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

The documents are developed with consideration of:

- 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 classes, along with the number of assets in each class.

Table 2–2: Jemena assets by asset class as at December 2018

Asset Class	Population	Asset Class	Population
Poles	102,766	Zone substation transformers	69
Pole top structures	136,253	HV outdoor fuses	6,155
Conductor (kilometres)	4,498	Surge arrestors	6,894
Overhead line switchgear	9,324	Pole type transformers	4,114
Automatic circuit reclosers	124	Non pole type distribution transformers	2,433
Public lighting luminaires	74,755	Zone substation Disconnectors	809
LV services (overhead and underground)	272,474	Underground cable (kilometres)	2,078
Zone substation circuit breakers	572	Zone substation instrument transformers	196 VTs 288 CTs
Communication equipment	607	Communications cable (metallic and fibre) (kilometres)	529
Zone substation capacitors	41	Zone substation DC systems	97
Power quality systems	58	Zone substation protection relays	2,005

2.2.5 ASSET CRITICALITY, PERFORMANCE AND RISKS

Jemena assesses the consequence of failure for each asset class, and selects an appropriate lifecycle management strategy for that asset class. The asset criticality determines the level of analysis required to formulate each asset 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 we 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, such as for underground cables.

Age based replacement is not used as a primary replacement strategy.

Some assets may exhibit premature failure due to onset of common defects (such as technology or design related issue). In this case we typically implement 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.

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 not utilised other than 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 future condition, performance and risk for network assets. We use our 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, a CBRM model is being applied to ten of the primary plant assets (nine asset classes). Jemena uses 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 (POF) 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 class.

Table 2–3: Asset lifecycle strategy for each asset class

Asset	Condition Assessment	Run To Failure	Age Based
Poles	✓ (1)		
Pole Tops	✓ (1)		
Conductors & 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	✓		
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 model 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 with regard to 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 a number of 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 with respect to employee and public safety.

System limitations identified through asset management

All of the network development projects listed in Section 5 have been identified within Jemena'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 which have an asset replacement cost greater than $200 thousand. These projects are identified through condition assessment as described in Jemena's individual asset class strategies; and
- Section 5.4 outlines the grouped network asset replacement programs where the individual asset replacement cost is less than $200 thousand.

2.2.6 FURTHER INFORMATION

Our 2016-2020 regulatory proposal, available at Jemena's website[4], includes more detailed information about our asset management framework and approach (Attachment 7-2), our asset management plans (Attachment 7-5) and our 20-year asset management strategy (Attachment 7-6).

[4] http://jemena.com.au/home-and-business/price-reviews/electricity/our-regulatory-proposal

2.3 DEMAND FORECASTING METHODOLOGY

Load 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.

Best practice distribution load forecasting

Jemena considers the following features necessary to produce best practice maximum 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), and growth in the numbers of air conditioning and heating systems; and
- Model validation and testing – including 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 sample forecast performance.

Jemena also considers the following elements to be relevant to maximum 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;
- Adjusting for discrete block loads – large new developments, such as shopping centres and housing developments, should be incorporated into the forecasts, taking into account of 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 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 peak demand forecasts, Jemena engages an independent consultant for the system level (top-down) forecasts, and prepares the spatial level (bottom-up) forecasts internally.

Section 4.3 discusses Jemena's review of the 2017/18 forecasts, as presented in the 2018 DAPR.

System level forecasts

Jemena engaged ACIL Allen to conduct econometric modelling for the 2019/20 – 2028/29 outlook period, to forecast maximum demand for the JEN network region as a whole (top-down).

The system level forecasts prepared by ACIL Allen include a summer and winter demand forecast for Jemena's total network, and for each period (summer and winter), a 10%, 50% and 90% POE maximum demand forecast is prepared.

The demand drivers the ACIL Allen forecast model uses include:

- An economic outlook for Victoria and for Jemena's supply area, as measured by the Victorian Gross State Product (GSP) growth rate (%) (refer to Figure 2-3);
- Growth in customer numbers in local government areas and for Jemena's supply area, as measured by customer growth rate (%) (refer to Figure 2-4);
- Solar photovoltaic (PV) generation capacity and battery storage based on analysis of historical installation rates and estimates of the financial return to solar PV and battery storage system owners (refer to Figure 2-5 and Figure 2-6 which shows the historic actual and forecast solar PV 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 2-7 which shows the year on year percent change in forecast Victorian assumed electricity prices used for ACIL Allen);
- Projections of demand impact arising from the uptake of electric vehicles. However, it is forecast that the impact of electric vehicles is relatively small over the forecast period; and
- Variation in temperature patterns (weather).

Figure 2-3: Victorian economic growth projections

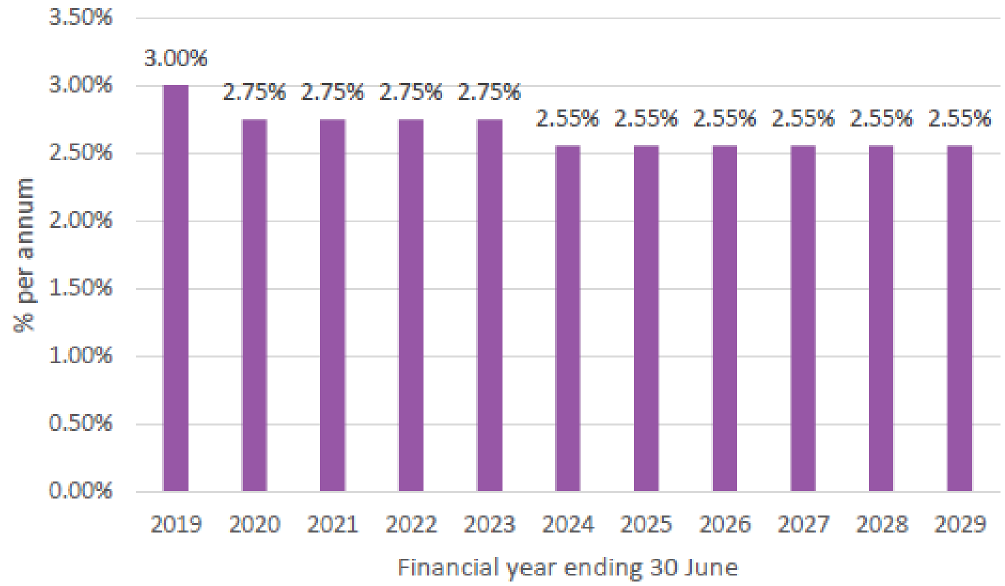


Figure 2-4: Projected annual population growth rates within Jemena's supply area

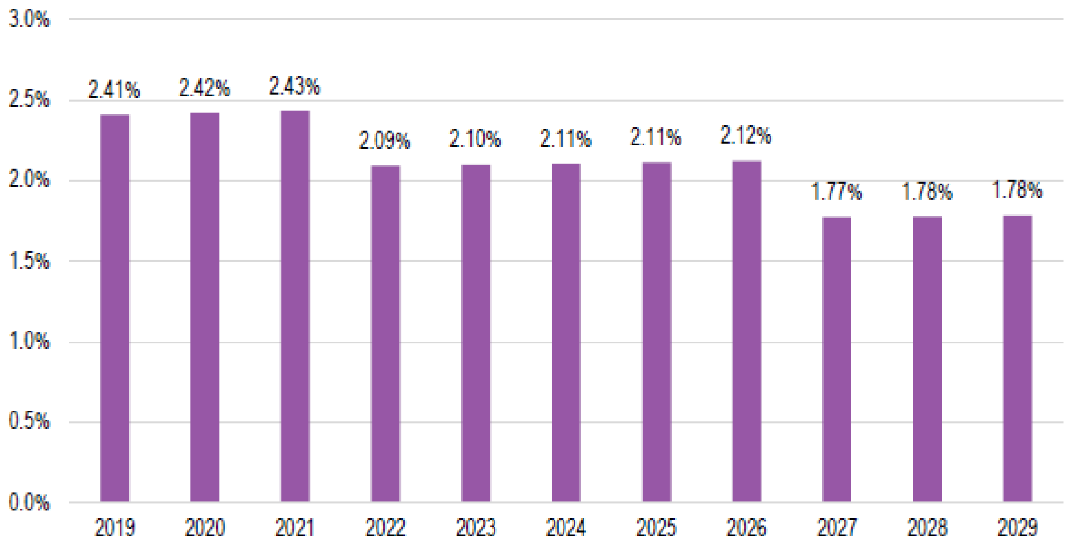


Figure 2-5: Cumulative capacity of installed solar PV systems within Jemena's supply area

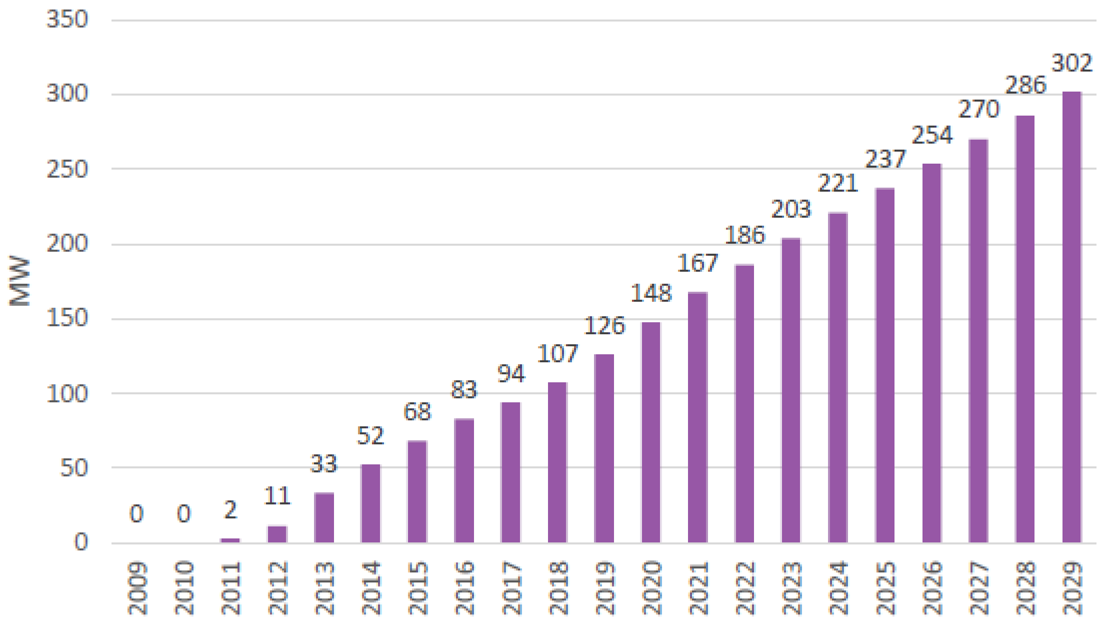


Figure 2-6: Forecast uptake of battery storage systems within Jemena's supply area

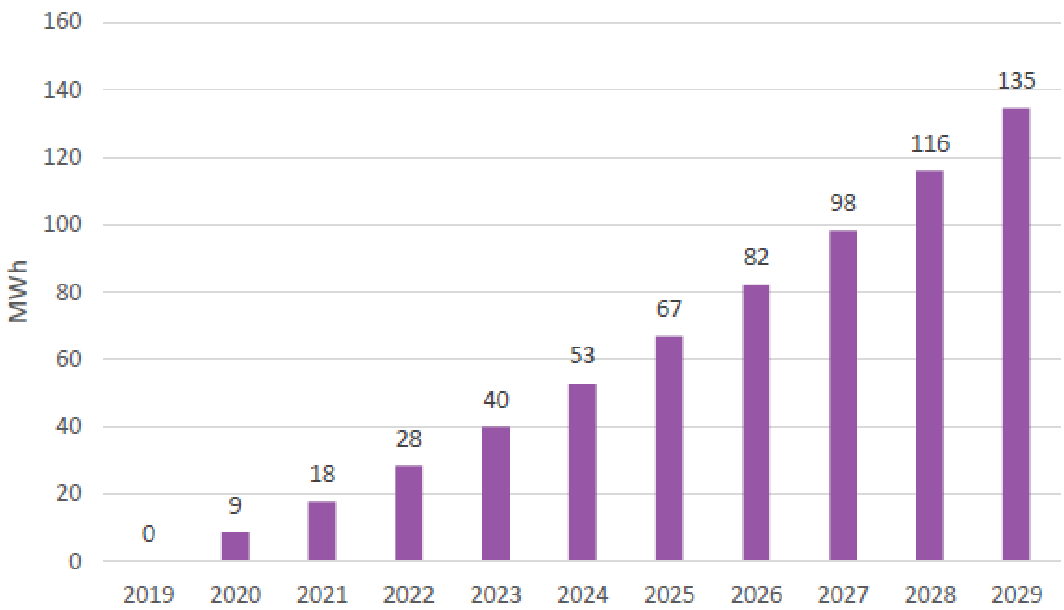
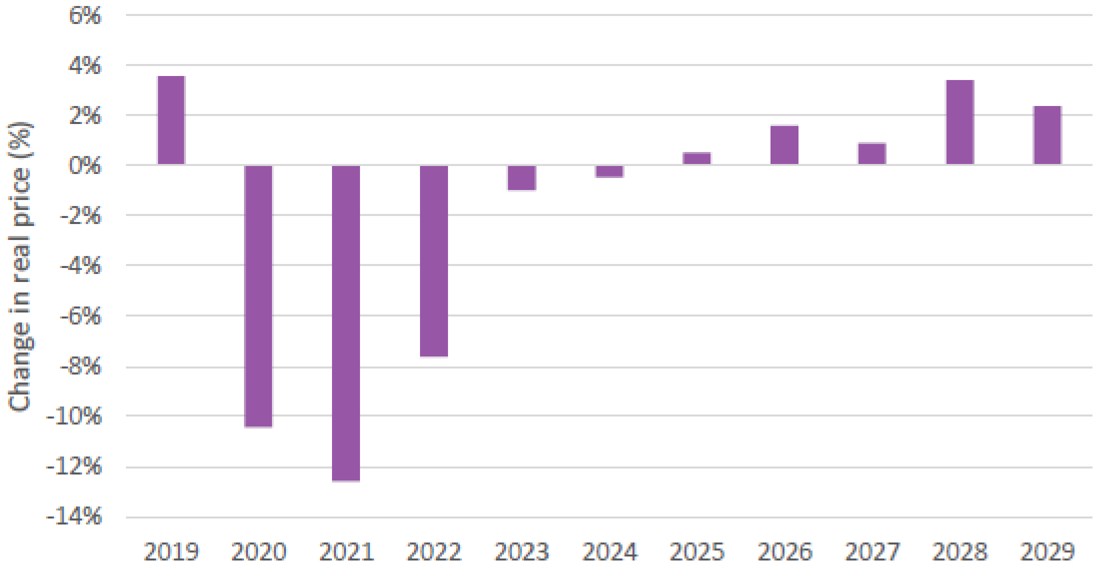


Figure 2-7: Forecast change in Victorian real electricity prices



The system level forecast methodology adopted by ACIL Allen Consulting includes:

- Establishing regression models, to quantify the relationship between electricity demand and its drivers;
- Producing baseline forecasts, using those models with forecasts of the drivers; and
- Preparation of models for demand in Jemena's region as a whole (top down).
- A post model adjustment to the forecasts to account for the impact of the ongoing up-take of solar PV system and projected up-take of battery storage system and electric vehicles. The process was conducted separately for summer and winter to produce independent forecasts of maximum demand for each season.

Spatial level forecasts

The spatial level forecasts prepared internally by Jemena 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, 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 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 prior to being included into 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 incorporating overall customer load changes (new or reductions), planned load transfers, and organic growth rate. Overall customer load changes and load transfers are diversified prior to being included into 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 are 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 - Jemena internal bottom-up forecasts are reconciled with the independent external top-down forecasts at the system level to account for factors such as government policies and economic conditions that 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 the non-coincident bottom up forecasts.

Spatial level forecasts are produced for summer and winter maximum demand periods. For each period a 10% and a 50% POE maximum demand forecast is prepared.

Jemena 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 for Jemena to achieve outcomes that are consistent with the NEO, the 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 growth was higher or lower than the actual. Consequently, without accurate spatial forecasts, efficient investment would not occur and customers would be exposed to outcomes that are uneconomic, including increased risk of supply interruptions.

In preparing the impact of customer load changes on its spatial forecasts, Jemena 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,[5] are also taken into account.

The principal developments driving significant demand growth in specific locations on the JEN network are outlined in Table 2–4.

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

Table 2–4: Key JEN Network Developments

Zone Substation	Section	Description
Braybrook	5.11.2	New high-rise residential and office buildings within Braybrook and Maidstone areas
Coburg South	5.11.6	On-going URD and commercial developments within the Pentridge area
Coolaroo	5.11.7	Continued expansion of URD estates within the Greenvale area
Fairfield	5.11.11	Redevelopment of the Amcor site in Fairfield to multiple high-rise residential and office buildings
Flemington	5.11.12	New high-rise residential and office buildings within Flemington area
Footscray East/ Yarraville	5.11.13 and 5.11.29	New high-rise residential and office buildings within the Footscray Central Activities District
Kalkallo and Somerton	5.11.16 and 5.11.22	Development of underground residential distribution (URD) and industrial estates in the Kalkallo, Craigieburn and Mickleham areas covered by the Northern Growth Corridor
Newport	5.11.17	
North Essendon	5.11.18	New high rise residential and commercial development in Mason Square, Hall Street, Moonee Ponds, and a proposed Moonee Valley Racecourse redevelopment
Sydenham	5.11.24	Continued URD estate developments

Transmission connection point forecasts

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

2.4 NETWORK PLANNING METHODOLOGY

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

2.4.1 PLANNING STANDARDS

Jemena is required to conduct its planning in accordance with the NER and the Victorian Electricity Distribution Code (EDC). Clause 5.13 of the NER requires Jemena to:

- Prepare forecasts, covering the forward planning period, of maximum demands for zone substation, sub-transmission 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 Jemena is required to carry out the requirements of the regulatory investment test for distribution (RIT-D)[6] and demand side engagement obligations; and
- Take into account any jurisdictional legislation.

Clause 3.1 of the EDC 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 which minimises costs to customers taking into account distribution losses.

To satisfy these obligations, Jemena 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 constraints and associated augmentation costs, including:

- Transmission connection points;
- Sub-transmission lines;
- Zone substations; and
- High-voltage (HV) feeders which 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, and expresses this economically by applying a value of customer reliability ($/MWh).

EUSE estimates the:

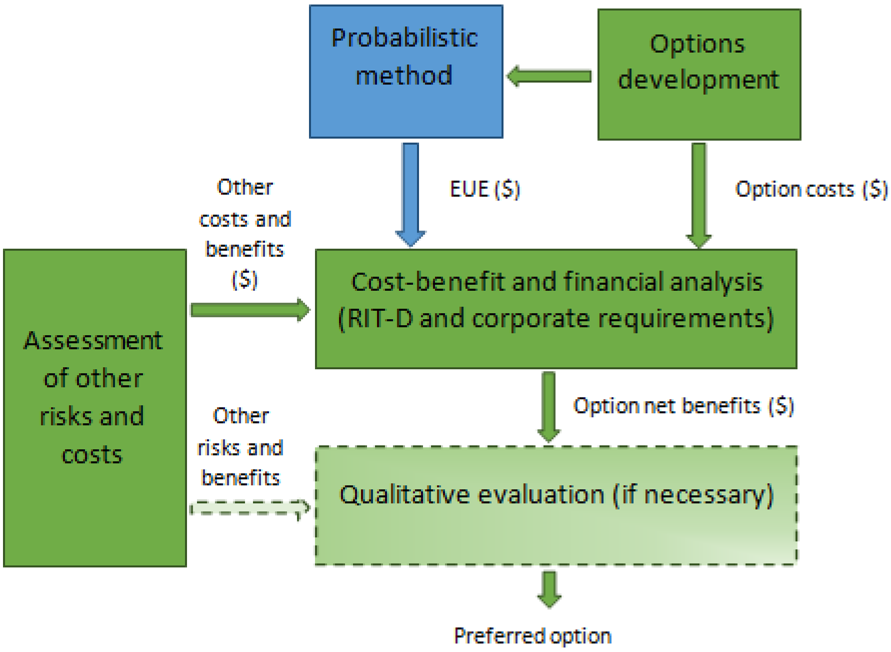
- Long-term probability weighted, average annual energy demanded by customers but not supplied; and
- Future degradation of electricity supply reliability as demand grows or changes.

The EUSE measure is then translated into an economic value, suitable for cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy.

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

Figure 2-8 shows how EUSE is used within the broader context of network planning.

Figure 2-8: 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
- Economic benefit is compared to 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 renewal needs. Unquantifiable risks and benefits can be qualitatively considered when selecting the preferred option.

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

- Network limitation assessment, which involves determining the extent of network constraints for various network contingency and demand forecast scenarios;
- Energy at risk analysis, where the maximum energy that is at risk of not being supplied due to these network constraints is determined;
- Expected unserved energy (EUSE) calculation, which considers the probability of the forecast demand and network condition (contingency) occurring; and
- Cost of EUSE, where the EUSE is transformed into a dollar cost by multiplying the value of customer reliability (VCR) 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 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 demand scenarios, which form a critical input for defining the maximum asset loading, and incorporate the:
  - Season (winter and/or summer). Although the JEN network is typically summer peaking, both periods are assessed because there may be some circumstances when a winter peak will exceed the relevant winter rating;
  - 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 temperature conditions; and
  - Economic growth assumptions, which define the likelihood that the actual maximum 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 the asset loading. However, without the necessary network support contracts, embedded generation cannot be relied on and, for the purpose of the DAPR limitation assessments, is assumed to not be generating at the time of maximum demand.
- 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 and the maximum load limit, and therefore the EUSE. Operator action considerations incorporate:
  - Reasonable expectations of what may actually 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 thermal rating assumptions
  - Asset thermal ratings, which typically define the loading limit and are selected to reflect the assumed contingency conditions; and
  - Power quality obligations, which under some circumstances, such as a steady state voltage limitation, can define the loading limit.

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.

In cases where the forecast maximum demand is approaching the ‘N secure’ rating of the zone substation, operational instructions are in place to manage the N risk under peak load conditions. These typically require the operators to split the zone substation bus by opening the bus tie circuit breaker when the station load exceeds a predetermined limit.

2.4.2.3 Energy at risk analysis

Energy at risk:

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

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

Figure 2-9 shows a load duration curve with a horizontal line representing the load limit of a specific contingency. Figure 2-10 shows the same figure, magnified around the part of the load duration curve closest to maximum demand. This effectively illustrates the energy at risk calculation, which is represented by the area under the load duration curve and above the load limit.

Figure 2-9: Load duration curve and load limit relationship

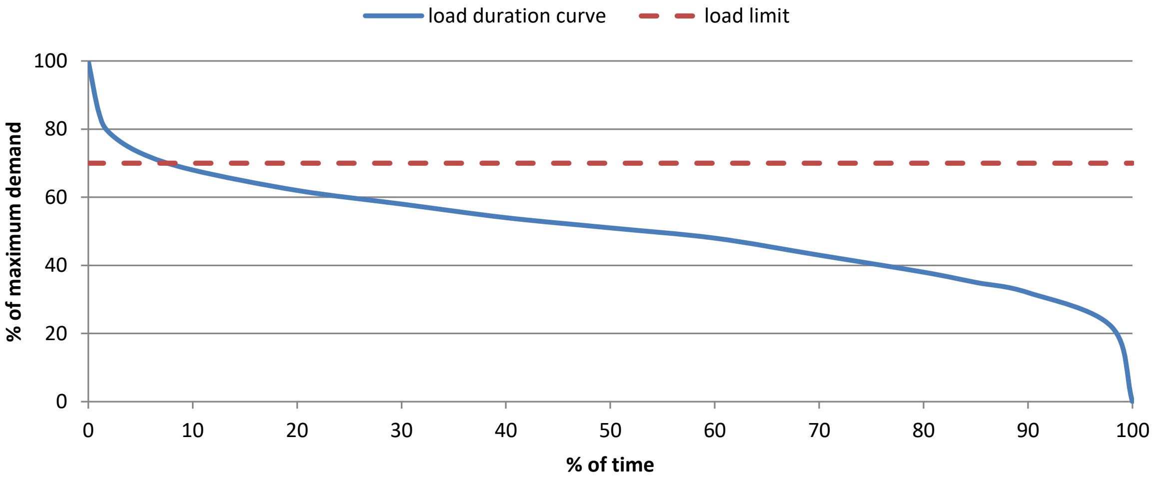
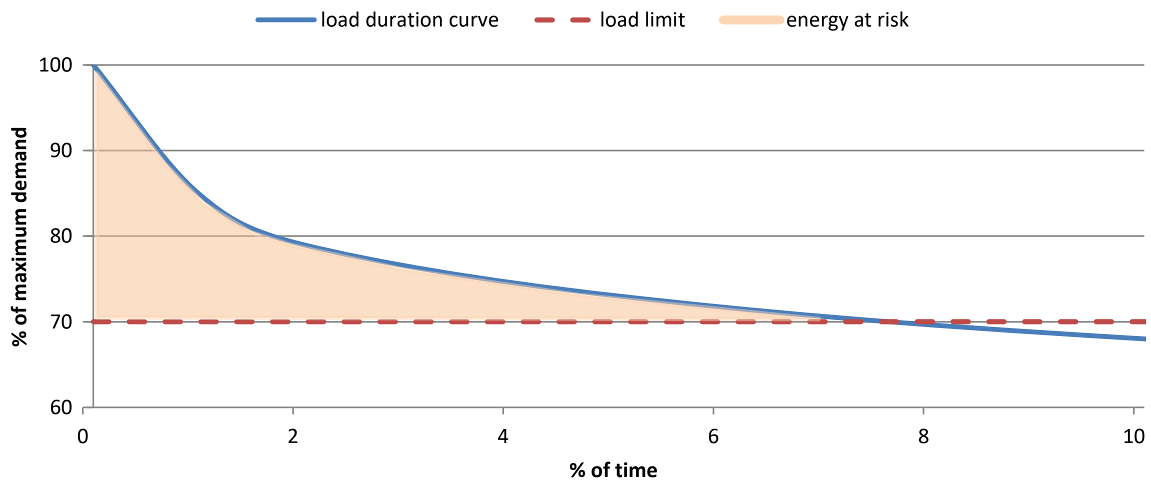


Figure 2-10: Energy-at-risk calculation for the area of the load duration curve above the load limit



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

- Reflects the maximum 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 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 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 demand scenario with the probability of that scenario, p_d.

The assumptions associated with calculating the total EUSE are:

- The probability weighting maximum demand scenarios – for the DAPR assessments, Jemena has weighted two maximum demand scenarios. The 10% probability of exceedance (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;
  - Sub-transmission line outage frequency, 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 frequency, 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 frequency, 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

The cost of EUSE 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 Market Operator (AEMO) or another appropriate body.

For the DAPR assessments Jemena has calculated a VCR of $41,331/MWh (in 2019 Australian dollars) to be applied to all limitation assessments. This VCR was developed using AEMO's 2014 value of customer reliability review[7] and applying Jemena's customer load composition, comprising an approximate 32% residential, 48% commercial and 20% industrial split. It includes an escalation factor of 1.068% to account for CPI from AEMO's 2014-15 values.

2.4.2.5 Calculation of sub-transmission loop EUSE calculation

The energy at risk for sub-transmission loops is determined as follows:

- Conduct network studies to determine the flow observed on the remaining in service sub-transmission lines, for an outage of one line;
- Where the post contingent flow on the remaining in service lines exceeds 120% of the line rating, determine the pre-contingency load reduction required such that the post contingent flow does not exceed 120% of the line rating. To determine the expected energy at risk, this pre-contingency load 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 ratings is determined from the additional load shed required and the contingency probability for the relevant line outage.

[7] AEMO. 2014 Value of customer reliability review. Available at http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review

In practise, load shedding prior to an outage would be a last resort for Jemena 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 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, and therefore expected unserved energy, 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 change in expected unserved energy calculations; however they are not separately reported in our assessments due to the complexity and limited benefit in doing so.

Power losses are typically only material in areas of the network supplying long sub-transmission 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 within our network, and are generally insufficient to justify augmentations without additional identified benefits, Jemena 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, again reducing load curtailment and any expected unserved energy.

For new feeders, or when upgrading a section of an existing feeder to increase its capacity, Jemena selects conductors, from its agreed standard conductors, that are optimised for the expected maximum load 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. Jemena maintains a set of standard conductors for its feeder designs, so as to minimise the carrying of spares.

For power transformers, Jemena has standard designs which have been selected based on their applicability and suitability for the Jemena network, and which 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. Jemena 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 on the guaranteed losses.

For distribution transformers, Jemena conducts a cost-of-life assessment which 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 high-voltage (HV) feeders where load 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;
- Is used for distribution substations and associated low-voltage (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:

- Maintaining the safe operation of assets; and
- 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:

- The maximum demand forecast scenario, where only the 10% POE scenario is applied;
- 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
- The loading limit, which represents the maximum permissible loading (relative to a reference thermal rating) for the assumed maximum demand forecast. For the DAPR assessments a loading limit of 100% of the HV feeder's capacity 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 demand scenario's probability of exceedance assumption, the asset loading, and the assumed 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 wind speed of 0.6 m/s is typically assumed in limit determination calculations.

3. NETWORK PERFORMANCE

This section describes the service target performance incentive scheme (STPIS), 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, Jemena 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 total minutes that a customer could expect to be without electricity over a specific period. Total SAIDI comprises both planned and unplanned 'off supply' minutes.
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. Unless otherwise stated, SAIFI excludes momentary interruptions (less than one minute duration).
Momentary Average Interruption Frequency Index (MAIFI)	Average number of momentary interruptions per customer	The average total number of momentary interruptions (less than one minute duration) that a customer could expect to experience in a year. MAIFI is calculated as the total number of customer interruptions of less than one minute duration, divided by the total number of connected customers averaged over the year.

3.2 HISTORICAL NETWORK PERFORMANCE

Jemena continually monitors network performance and internally reports actual performance against STPIS targets on a monthly basis. All aspects of Jemena's business, from asset management and investment strategies to network control and monitoring, contribute to network performance and have resulted in five of seven STPIS key performance indicators being met in 2018.

Network performance in 2018 has outperformed the previous best performance achieved in 2017 (excluding the MED) and marks the best performance achieved in JEN's 24 year history in terms of SAIFI. SAIDI was second best compared to 2017. 2018 was warmer and drier than average. It was Victoria's third warmest year on record with January being -warmest on record. There were some storm events but overall there was minimal impact to the network.

Asset replacement programs such as Pole Top Fire Mitigation, Surge Diverter Replacement, Non-Tension Connector Replacement, Switch Replacement, Distribution Substation Augmentation, and network reliability programs such as Auto Circuit Recloser, Remote Control Switching and Fault Monitoring Installation, and fault investigations have all had a positive impact on network performance. Table 3–2 and Table 3–3 summarise our network performance for 2018, compared to the performance indicators set by the Australian Energy Regulator (AER) under the STPIS.

Table 3–2: 2018 network performance

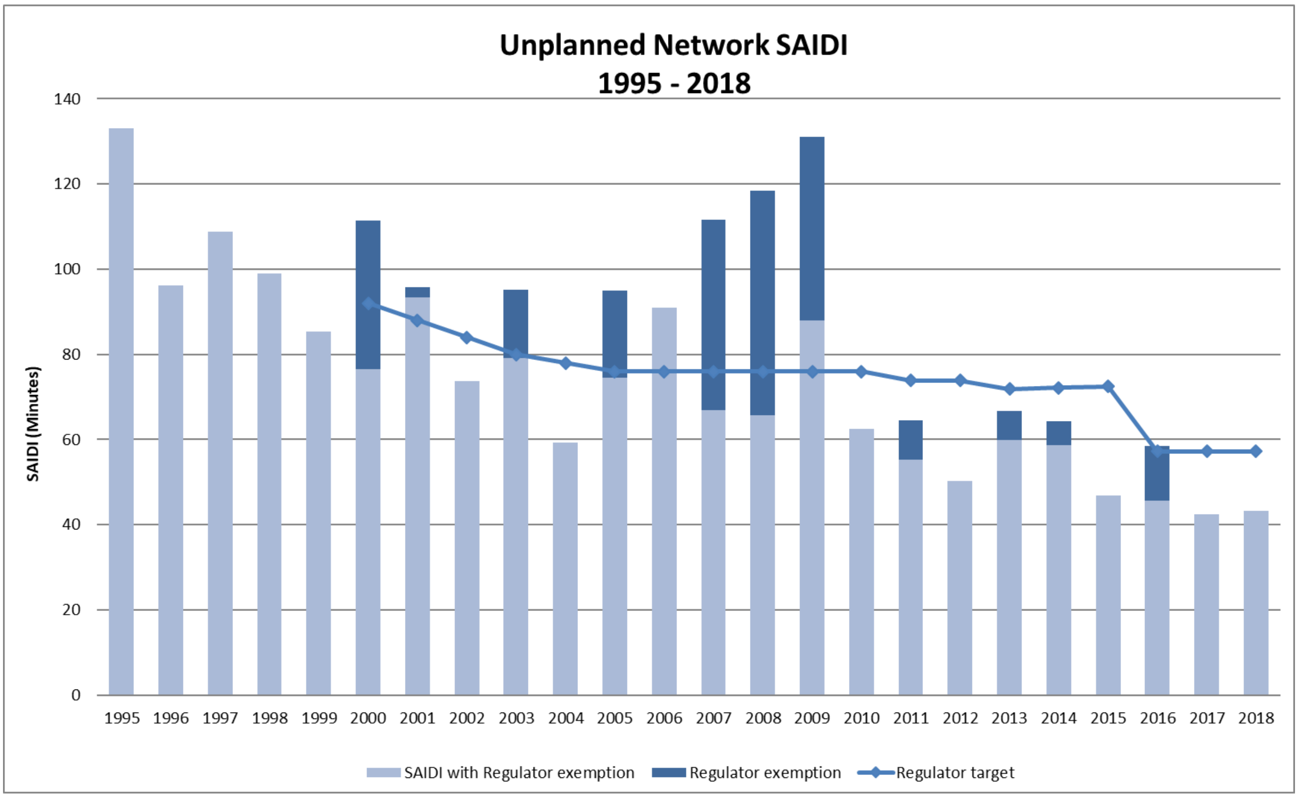
Measure	Target		Actual	
	Urban	Rural-Short	Urban	Rural-Short
Unplanned System Average Interruption Duration Index (SAIDI)	55.401	91.955	43.321	41.282
Unplanned System Average Interruption Frequency Index (SAIFI)	0.954	1.238	0.723	0.867
Momentary Average Interruption Frequency Index (MAIFI)	0.756	1.654	0.818	2.087

Table 3–3: 2017 network customer service performance

Measure	Target	Actual
Telephone answering: % of calls will be answered within 30 seconds	64.235	77.158

Figure 3-1 shows Jemena's historical network performance for unplanned SAIDI (between 1995 and 2018) compared to the regulator's performance targets (from year 2000).

Figure 3-1: Historical unplanned SAIDI network performance (1995-2018)



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:

- 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
- A guaranteed service level (GSL) component whereby customers are paid if they experience service below a predetermined level

As part of Jemena's 2016-2020 regulatory proposal agreed to by the AER in May 2016, Jemena will maintain the performance levels that occurred during the 2011-2015 regulatory period, with performance targets set based on average actual network performance measured between 2010 and 2014, as per AER methodology.

Table 3–4 and Table 3–5 presents Jemena's annualised performance targets for the 2016-2020 period as agreed by the AER.

Table 3–4: 2016-2020 network performance targets

Measure	Urban	Rural- Short
Unplanned System Average Interruption Duration Index (SAIDI)	55.401	91.955
Unplanned System Average Interruption Frequency Index (SAIFI)	0.954	1.238
Momentary Average Interruption Frequency Index (MAIFI)	0.756	1.654

Table 3–5: 2016-2020 network customer service target

Measure	Network
Telephone answering: % of calls will be answered within 30 seconds	64.235

Details of the STPIS to apply to Jemena for 2016-2020 can be found on the AER website[8].

3.3.1 FORECASTING NETWORK PERFORMANCE

Jemena's capital and operational expenditure plans are based on the principle of maintaining network reliability performance. 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, O&M 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 2016-2020 period, and agreed to by the AER in its May 2016 final determination, Jemena forecasts that it will meet or exceed the network performance targets in Table 3–4 and Table 3–5 above.

[8] http://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2016-20/final-decision

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 focusses 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.

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; and
- Identifying and replacing or phasing out fault-prone assets.

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

3.5 QUALITY OF SUPPLY

Jemena is required to comply with the requirements in Section 4 of the Victorian Electricity Distribution Code (EDC), and Schedule S5.1a of the National Electricity Rules (NER).

Given a customer can connect anywhere on the network, Jemena 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 4.2 of the EDC specifies the requirements for steady state voltages, voltage variations (sags and swells) and impulses (transients) at customers' supply points, which is summarised in Table 3–6.

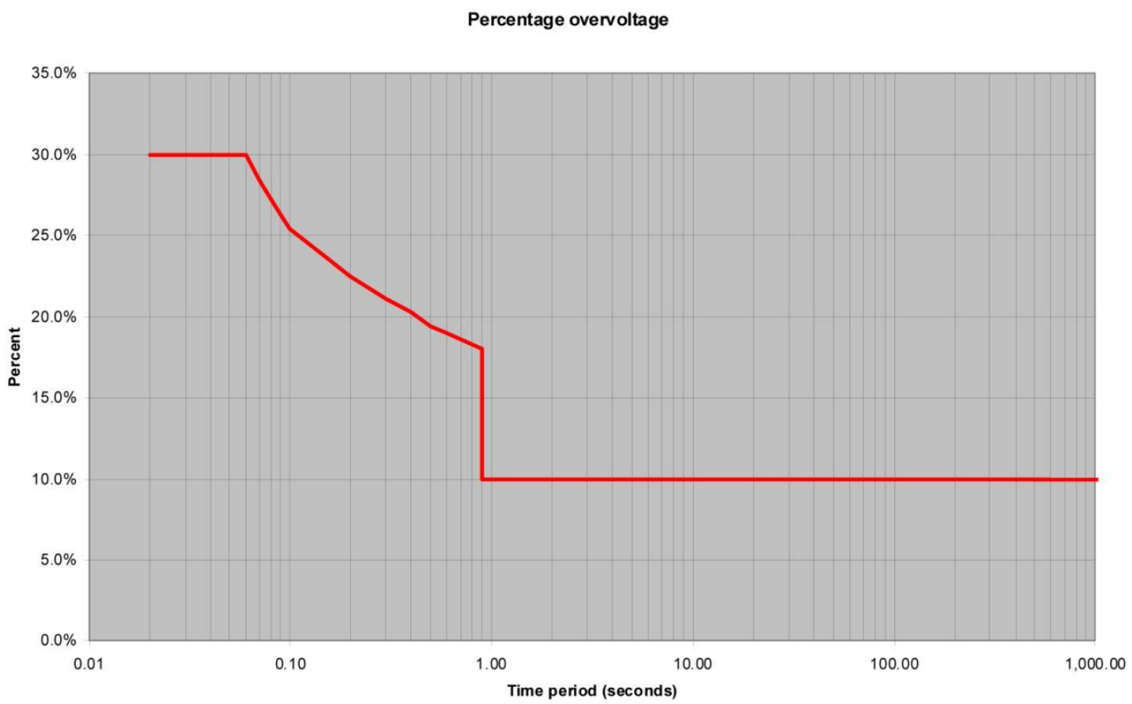
Table 3–6: EDC standard nominal voltage variations

Voltage	Steady State	Less than 1 minute	Less than 10 seconds	
			Ph-E	Ph-Ph
< 1.0 kV	+10 % - 6 %	+14% - 10%	+50% -100%	+20% -100%
1 – 22 kV	± 6 % (± 10 % Rural Areas)	± 10 %	+80% -100%	+20% -100%
66 kV	± 10 %	± 15%	+50% -100%	+20% -100%

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 3–6 does not apply. The Phase to Phase voltage variation in Table 3–6 apply to that part of the distribution system experiencing REFCL condition. Refer to section 5.10 for further information on the impact on the Jemena Electricity Network 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 3-2, which is an extract of Figure S5.1a.1 in the NER.

Figure 3-2: NER overvoltage limit due to a contingency event



Harmonic voltage distortion

Table 3–7 summarises the requirements for voltage harmonic levels at the customers' supply points, which are described by:

- Clause 4.4 of the EDC. This requirement is based on the former Australian standard AS2279.2, which was withdrawn by most Australian states in 2001; and
- Clause S5.1a.6 of the NER, which requires compliance with AS/NZS 61000.3.6.

The EDC is more stringent for total harmonic distortion (THD) and low frequency harmonics for which the JEN network is likely to experience, whereas the NER is more stringent for higher frequency harmonics. The Victorian DBs have initiated discussion with the ESC on possible revision to the EDC for the THD standard.

Table 3–7: Harmonic levels at customer supply points

<table>
<tr><th rowspan="2"></th><th colspan="3">EDC</th><th colspan="3">NER</th></tr>
<tr><th>THD</th><th>Odd harmonics</th><th>Even harmonics</th><th>THD</th><th>Odd harmonics</th><th>Even harmonics</th></tr>
<tr><td rowspan="2">Low voltage
(< 1 kV)</td><td rowspan="2">5 %</td><td rowspan="2">4 %</td><td rowspan="2">2 %</td><td rowspan="3">8 %</td><td>3^{rd} = 5 %
5^{th} = 6 %
7^{th} = 5 %</td><td>2^{nd} = 2 %
4^{th} = 1 %
6^{th} = 0.5 %</td></tr>
<tr><td colspan="2" rowspan="2">For higher orders refer AS/NZS 61000.3.6:2001</td></tr>
<tr><td>Medium / High voltage (> 1 kV)</td><td>3 %</td><td>2 %</td><td>1 %</td></tr>
</table>

Voltage unbalance (negative sequence voltage)

Table 3–8 summarises the requirements for voltage unbalance, defined by the negative phase sequence voltage, at the customers' supply points, which are described by:

- Clause 4.6 of the EDC; and
- Clause S5.1a.7 of the NER.

The voltage unbalance requirements of the EDC are more stringent than the NER and are not achievable for all customers. The basis for the EDC limits is unclear, but the NER limits are based on international standards. The Victorian DBs have initiated discussion with the ESC on possible revision to the EDC for voltage unbalance standard.

Table 3–8: Voltage unbalance at customer supply points

<table>
<tr><th rowspan="2"></th><th rowspan="2">EDC</th><th colspan="3">NER</th></tr>
<tr><th>30 min average</th><th>10 min average</th><th>1 min average (once per hour)</th></tr>
<tr><td>< 10.0 kV</td><td rowspan="2">1.0 %</td><td>2.0 %</td><td>2.5 %</td><td>3.0 %</td></tr>
<tr><td>> 10 kV</td><td>1.3 %</td><td>2.0 %</td><td>2.5 %</td></tr>
</table>

Flicker (disturbing load)

Table 3–9 summarises the requirements for voltage flicker at the customers' supply points, which are described by:

- Clause 4.8 of the EDC. This requires compliance with AS/NZS 61000.3.5 for LV systems, and AS/NZS 61000.3.7 for MV and HV systems; and
- Clause S5.1a.5 of the NER, which specifies identical requirements but also specifies that the DNSP must define the planning levels.

Table 3–9: Flicker at customer supply points

Voltage	PST	PLT
< 1.0 kV	1.0	0.8
1 – 22 kV	0.9	0.7
66 kV	0.8	0.6

3.5.1 POWER QUALITY MONITORING COVERAGE

Every JEN network 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. It is noted however, that the fleet of power quality monitors is aging, with many nearing 20 years of age and Jemena has initiated a planned replacement program over the forward planning period as described in Section 5.4.8.

On the low voltage network, the completed rollout of AMI meters has allowed basic power quality monitoring of the customer connection points in the low voltage distribution system. However, to date these meters have only been able to report voltage disturbance events which are outside of EDC limits, and little additional information about these events. Jemena has completed a “supply monitoring” project which acquire 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.

In this year’s Long-Term National Power Quality Survey (LTNPQS), Jemena has included 1,879 3-phase smart meter sites in addition to the end-of-feeder power quality monitors. Due to the significant increase in LV sites, survey result in this DAPR is shown for the “worst 50” sites only.

3.5.2 LV POWER QUALITY PERFORMANCE

The data obtained from AMI meters on Jemena’s network indicate that there are customers who are experiencing steady state voltages outside of EDC limits for 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. Jemena is investigating options to proactively bring the voltage back into compliance.

3.5.3 MV POWER QUALITY PERFORMANCE

Jemena participates in the Long-Term National Power Quality Survey (LTNPQS) conducted annually by the University of Wollongong. This survey provides analysis of steady-state voltages, voltage unbalance, voltage harmonics, voltage sags and swells, and flicker. To date, Jemena has only provided power quality data from the 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 2018/19 financial year is summarised in Figure 3-3. The performance of each 6.6 kV zone substation is summarised in Figure 3-4. The summary of the worst 50 LV sites is summarised in Figure 3-5. The results show all 6.6kV, 11kV and 22kV zone substations are compliant. For the worst 50 LV sites (out of a total of nearly 1,900 sites surveyed) there are both high and low voltage instances. Jemena is implementing a number of proactive meaures to bring these sites back into compliance.

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

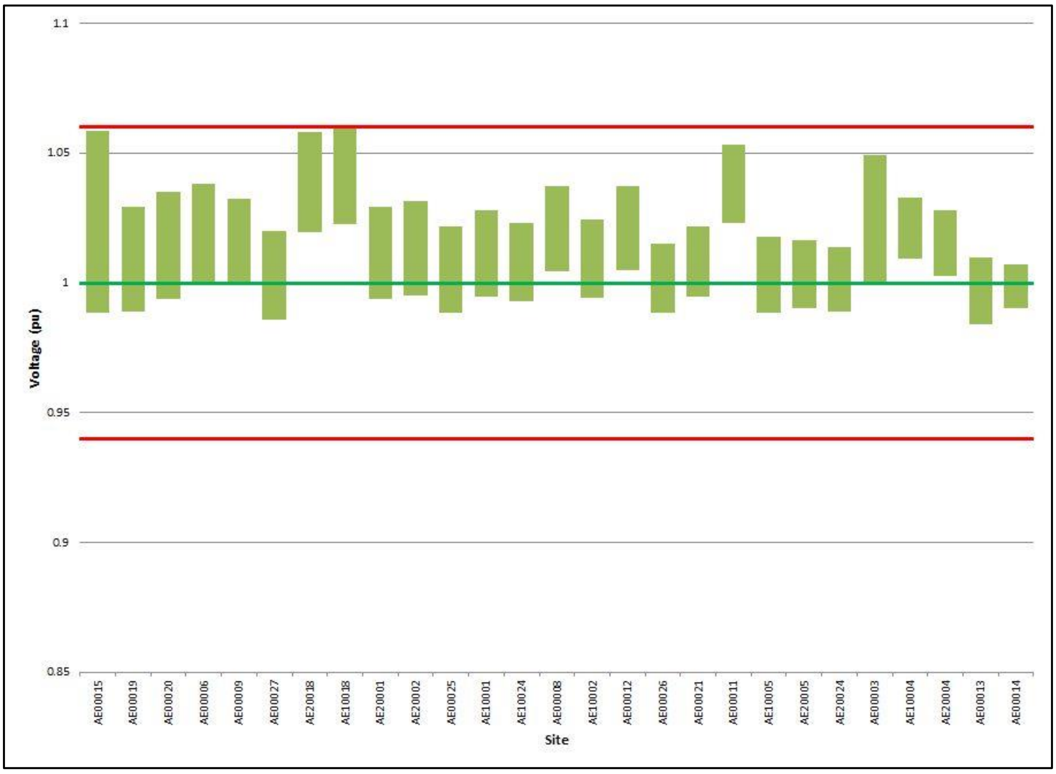


Figure 3-4: Steady state voltage performance – 6.6 kV sites

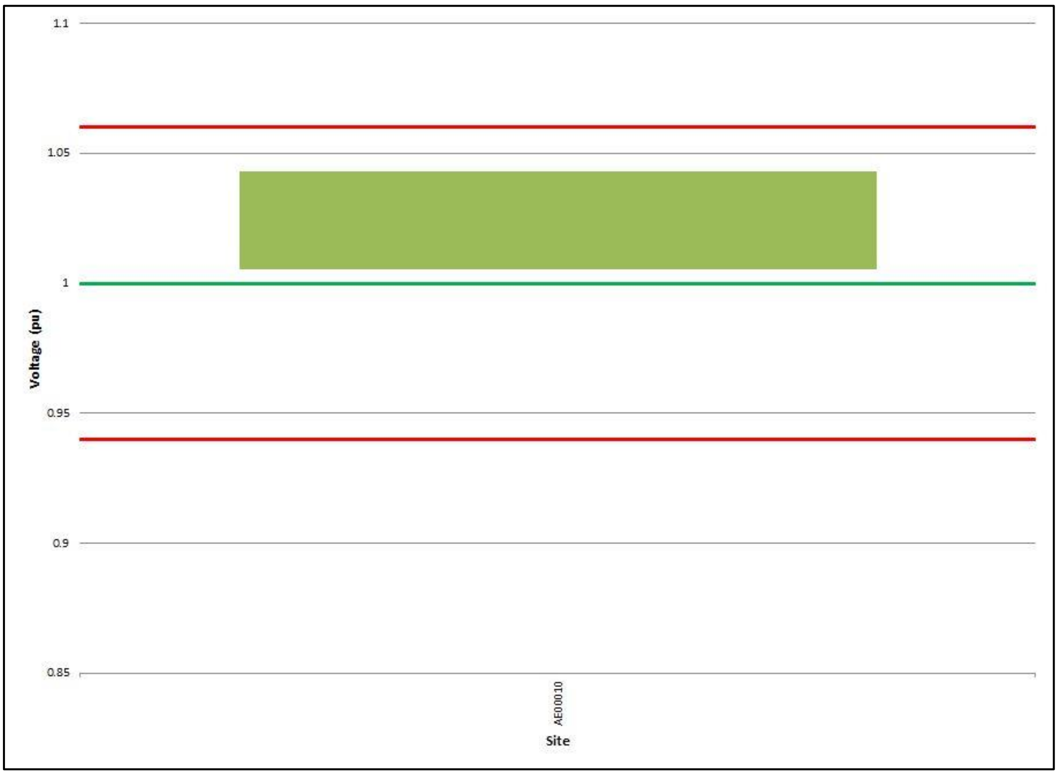
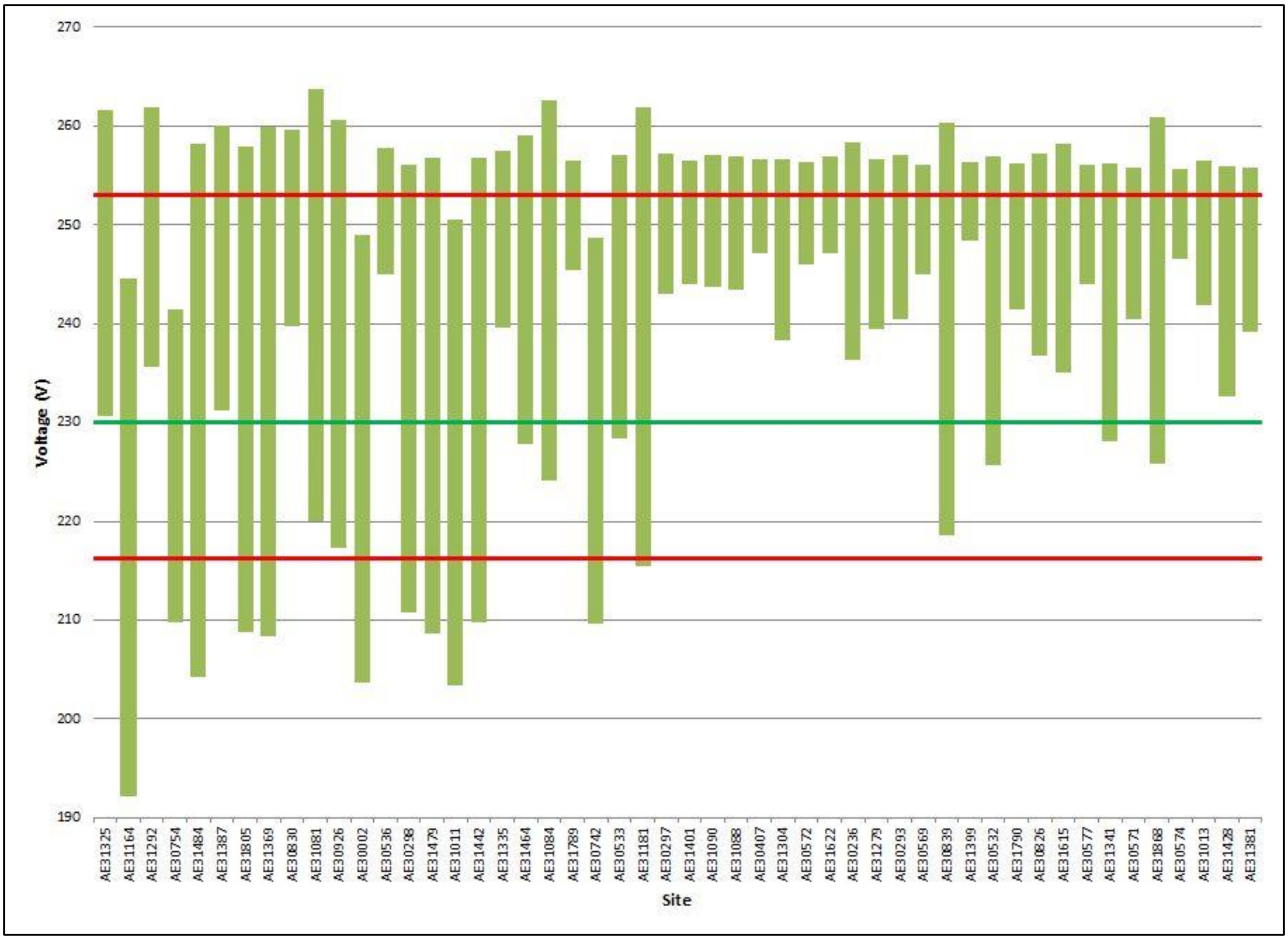


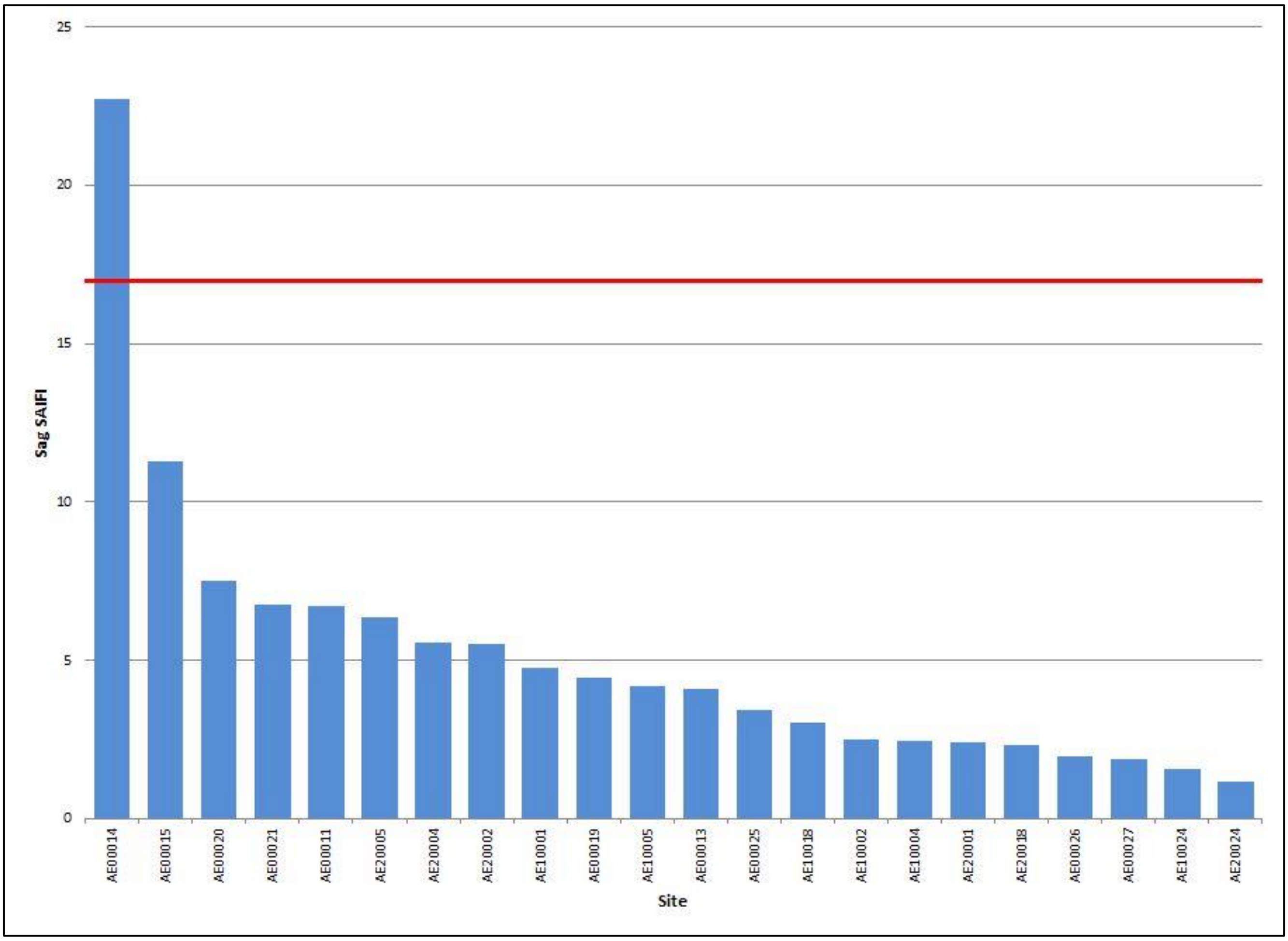
Figure 3-5: Steady state voltage performance – LV sites (worst 50)



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 2018/19 financial year is summarised Figure 3-6. All of these sites are within the limits applied by the LTNPQS analysis.

Figure 3-6: Voltage sag performance – 22 kV & 11 kV sites



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 2018/19 financial year are presented in Figure 3-7. Results for each 6.6 kV zone substation are presented in Figure 3-8. These results show that the total harmonic distortion (THD) is below the 3% EDC limit at the majority of zone substations. One site has been identified that is beyond EDC limits (but below NER limits). Harmonic distortion levels at this site will be subject to further investigation.

Figure 3-7: Harmonic distortion levels – 22 kV & 11 kV sites

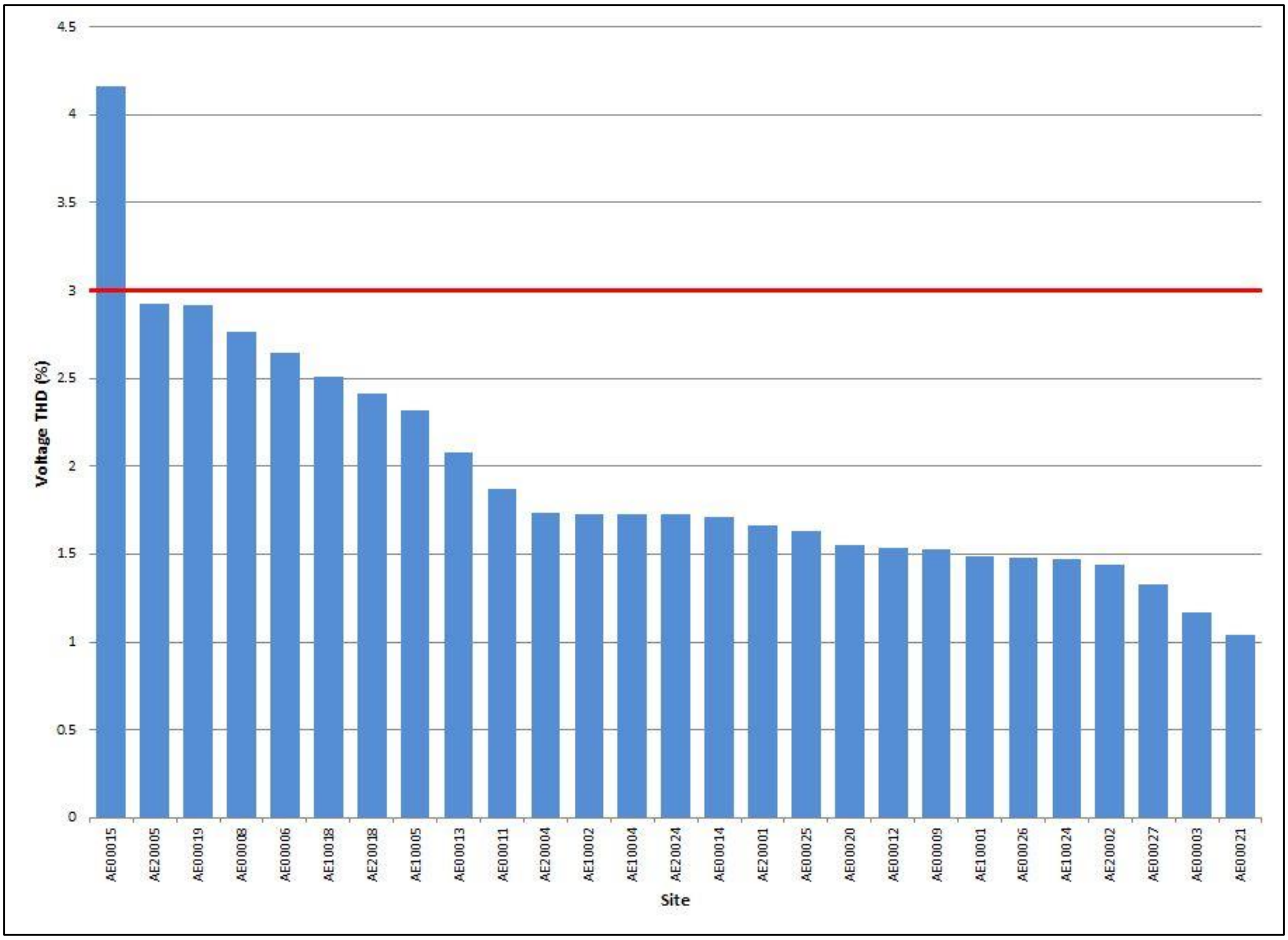
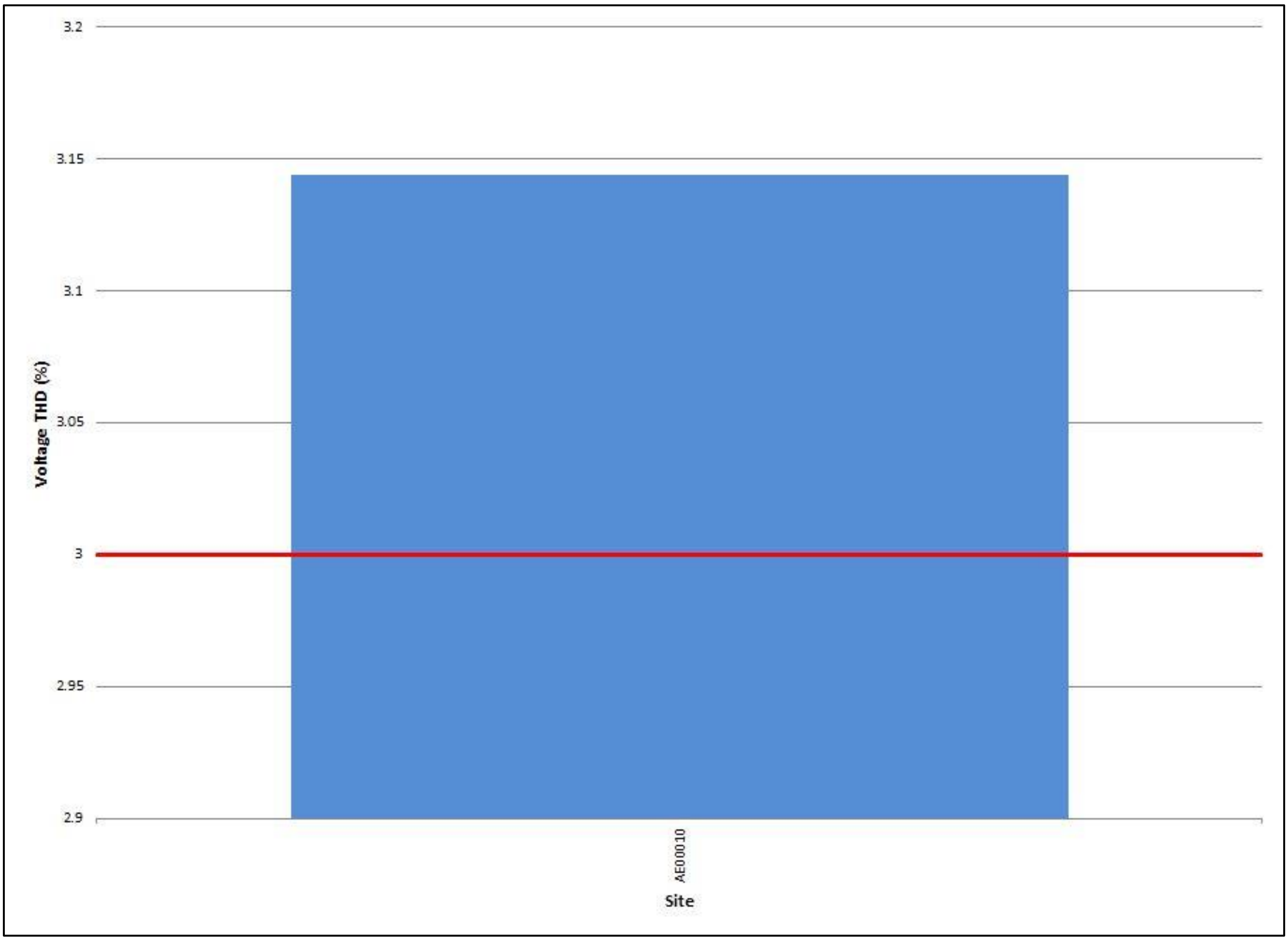


Figure 3-8: Harmonic distortion levels – 6.6 kV sites



Voltage unbalance performance

Voltage unbalance is recorded by permanent power quality meters installed at Jemena's zone substations, and can be calculated for 3-phase smart meter sites. Results for each 22 kV and 11 kV zone substation for the 2018/19 financial year are presented in Figure 3-9. Results for each 6.6 kV zone substation are shown in Figure 3-10. Results for the worst 50 LV sites are shown in Figure 3-11. The results show that there has been a decrease in the unbalance levels across the network compared to the 2017/18 results however the 1% unbalance limit specified in the EDC is still exceeded at a number of the sites.

Figure 3-9: Voltage unbalance (negative sequence voltage) – 22 kV & 11 kV sites

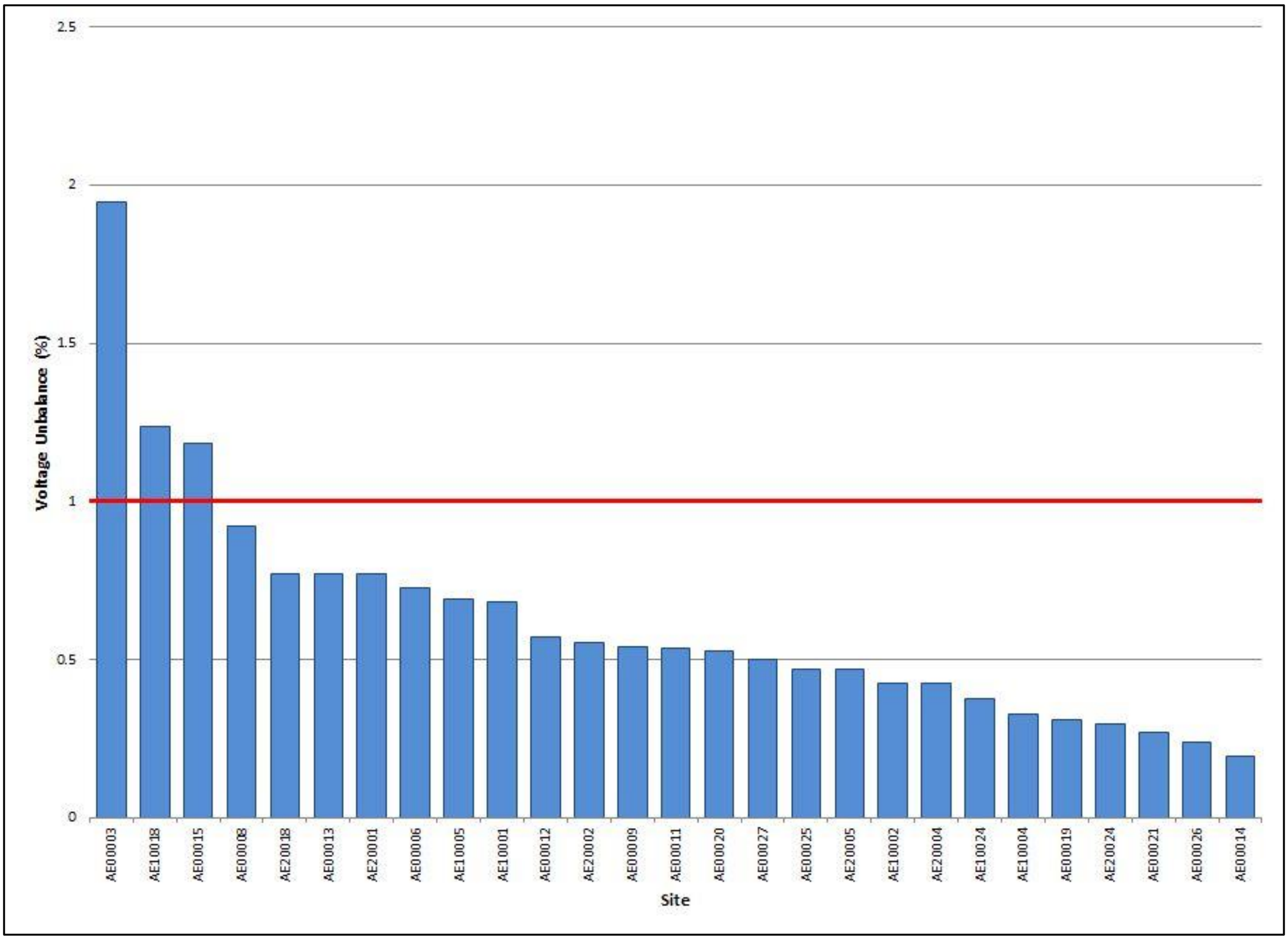


Figure 3-10: Voltage unbalance (negative sequence voltage) – 6.6 kV sites

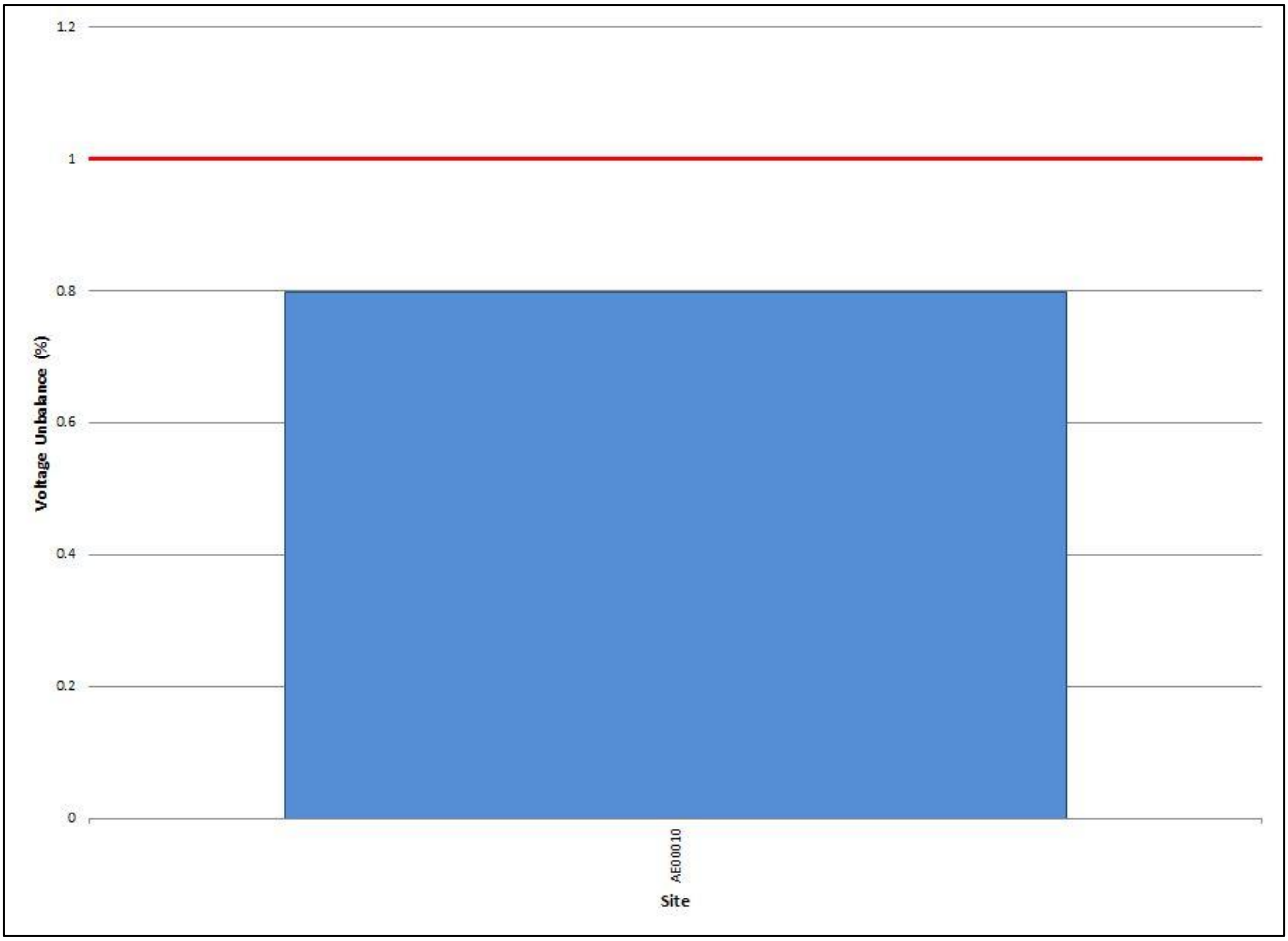
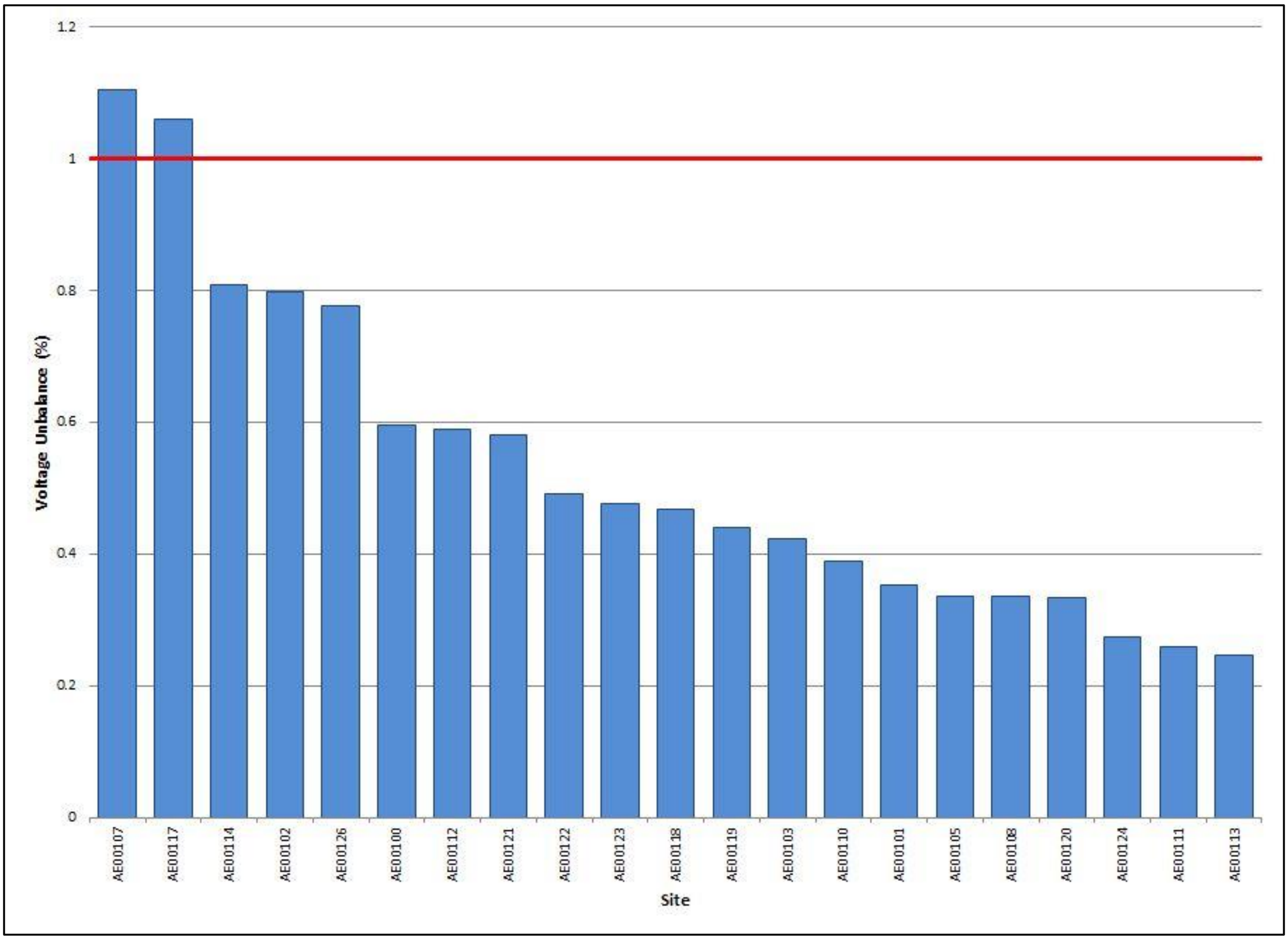


Figure 3-11: Voltage unbalance (negative sequence voltage) – LV sites (worst 50)



Flicker performance

Although flicker cannot be directly measured due to measurement limitations of Jemena'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 2018/19 financial year, presented in Figure 3-12 and Figure 3-13, indicate that Jemena is compliant at the MV sites where power quality is monitored.

Figure 3-12: Voltage flicker levels – Pst distribution

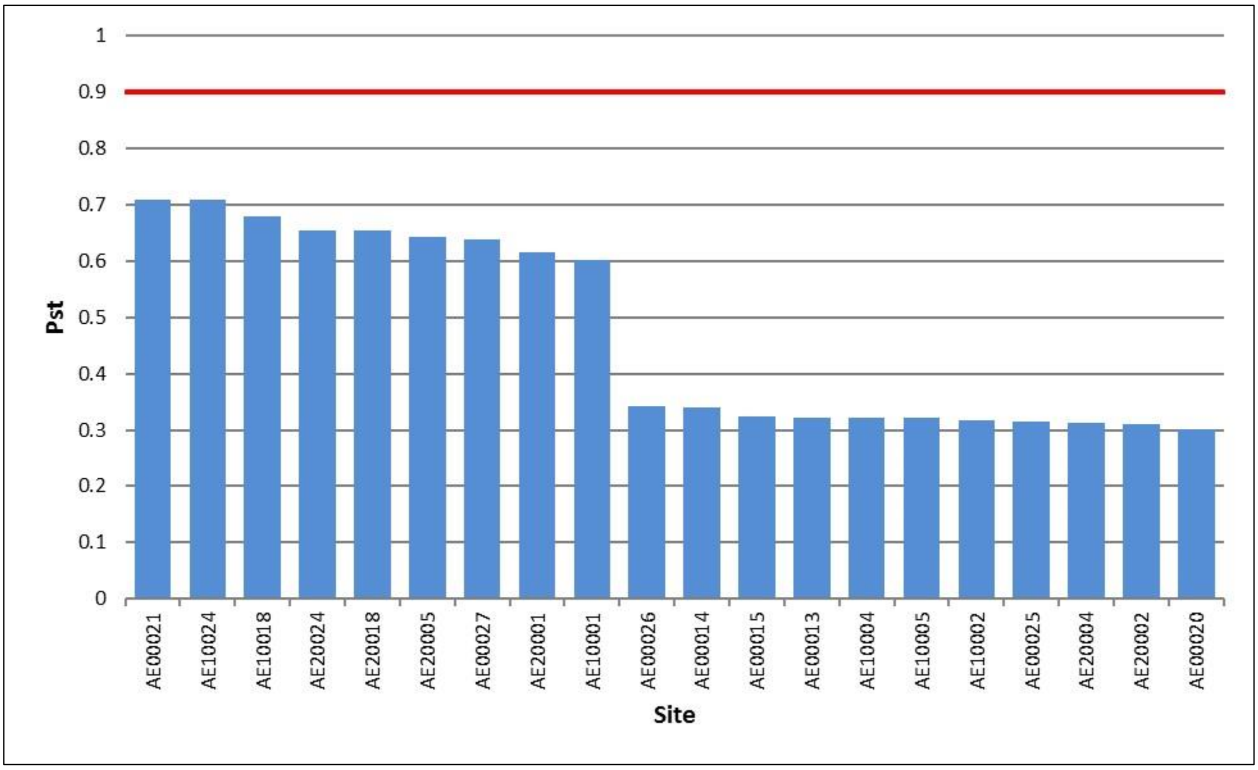
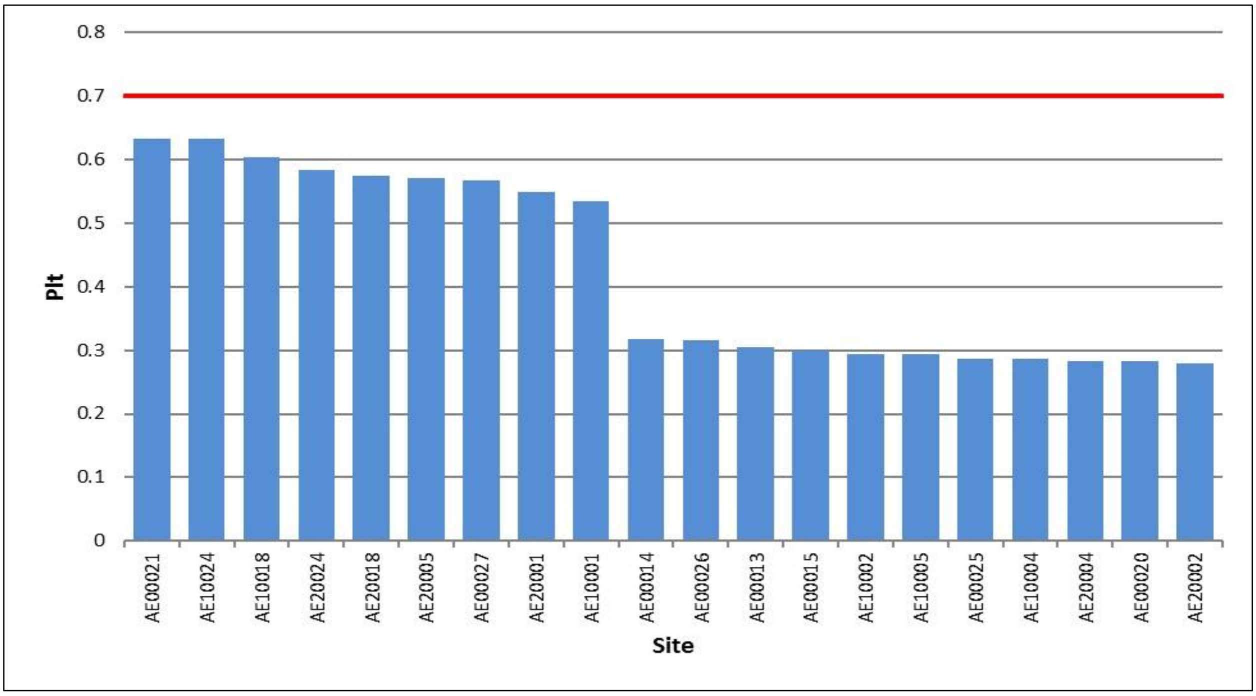


Figure 3-13: Voltage flicker levels – Plt distribution



3.5.4 POWER QUALITY CORRECTIVE ACTIONS

When Jemena 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 a period of seven days. If the results obtained from these devices confirm that there is a network problem, Jemena 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; or
- Re-conductoring of LV circuits.

With the availability of 5-minute snapshots of power quality data and the establishment of an advanced data analytics platform, Jemena 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, are progressively implemented.

On the MV network, with power quality in 2018/2019 generally within regulatory requirement, Jemena's power quality corrective action is primarily focussed on monitoring and maintaining existing power quality levels.

There are no specific works in 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

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

Distribution substation on-load tap changer feasibility study

Voltage disturbances occurring on the LV network due to increased penetration of residential and commercial solar photovoltaic (solar PV) generation and emergence of new 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 has talked to a number of transformer manufacturers on the concept of a distribution transformer fitted with an on-load tap changer. While commercial products are available and are being deployed overseas (e.g. Europe), in Australia it appears that the product is still at a prototype stage.

Jemena has implemented a pilot project for the installation of one 22 kV and one 11 kV distribution transformers with on-load tap changing facility. The installations have been completed and Jemena is monitoring the performance of the voltage regulation scheme.

Smart PV inverter feasibility study

As voltage issue on the LV network is contributed in part by increasing penetration of roof-top 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. Jemena is investigating the effect of smart PV inverters on voltage delivery by trialling smart inverter functions on the 100kVA system installed in its Broadmeadows depot.

Supply monitoring project

Since the beginning of 2017 Jemena has been implementing a “supply monitoring” project which involves the collection of time synchronised data (voltage, current and power factor) from every AMI meter at 5-minute intervals. In 2017 the software system for the acquisition of 5-minute data was commissioned and by July 2018 we achieved the collection of 5-minute data from over 95% of the AMI meters. A hardware platform for running advanced data analytics has been installed and a number of data analytics algorithms have been developed:

- Supply neutral integrity monitoring – provides round-the-clock monitoring of the integrity of the service wire/cable that connects into customer premises. High impedance connection on the service line/cable presents a health & safety hazard to the customers and could develop into widespread supply outage if the condition is not detected and rectified in time. This functionality has been successfully tested and is being rolled out across the whole network. To date we have now addressed broken/high resistance neutrals affecting over 500 customers and rectification work is on-going.
- 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 which can be used to balance loads/generations between phases, improve asset utilisation and improve quality of supply to its customers. 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 we have achieved pleasing results from the data analytics algorithms so far, more work is required to improve the accuracy including site measurements 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

A 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 Jemena’s GIS. We are working on a simulation facility which allows the effect of new DER to be modelled before it is connected to the network.

4. NETWORK DEMAND FORECASTS

This section presents:

- Jemena's network wide historical actual demand;
- A comparison of the 2019 summer maximum demand forecasts with the forecasts published in the 2018 DAPR;
- A review of the accuracy of terminal station and zone substation maximum demand forecasts for 2019 against observed maximum demand;
- A review of penetration levels of both residential and commercial rooftop solar PV on Jemena's network; and
- Current utilisation statistics for Jemena's zone substations and HV feeders.

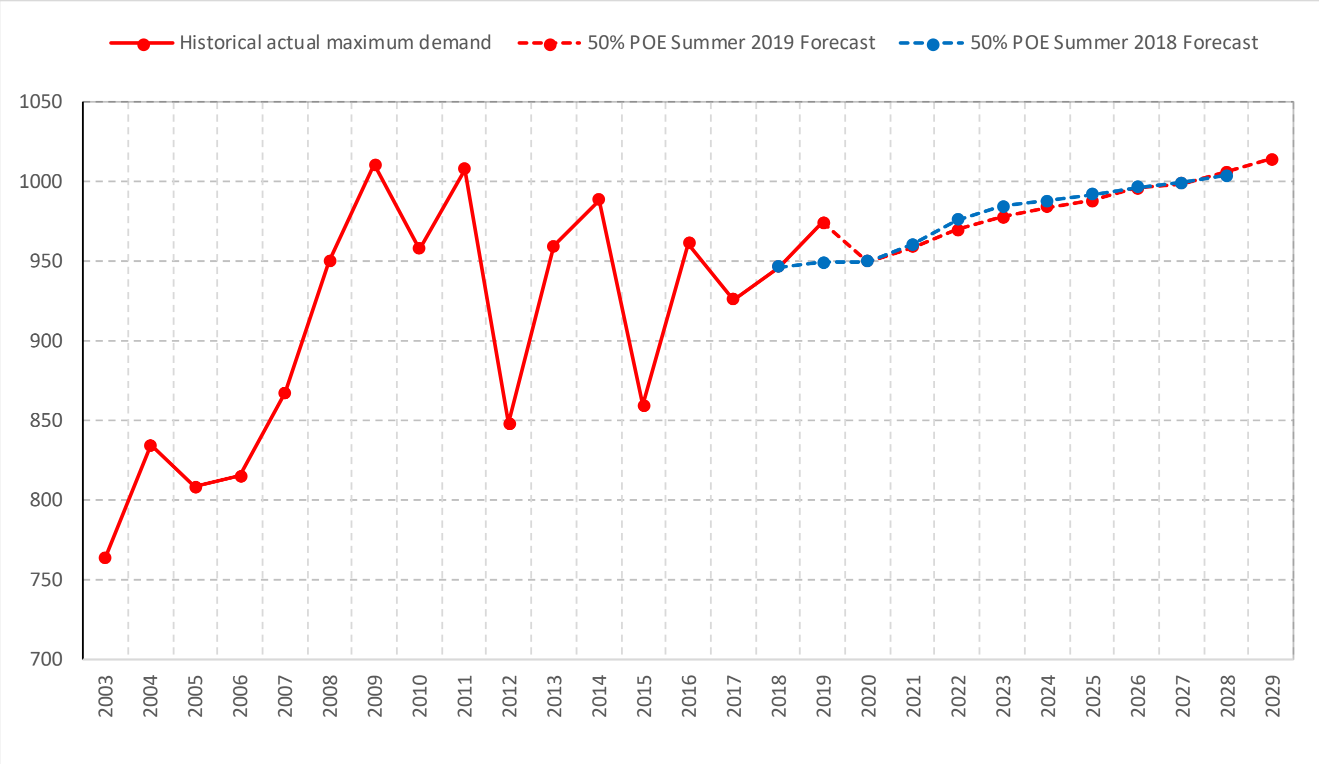
Demand and energy forecasts for Jemena's connection points can be found in the 2019 TCPR, which is available on Jemena's website[9].

4.1 CHANGES TO DEMAND FORECASTS

Figure 4-1 shows the historical summer maximum demand on Jemena's electricity network since 2003 and a comparison of the 2018 to current (2019) ACIL Allen system level (top-down) maximum demand forecasts for the JEN region over the 2019/20 – 2028/29 outlook period.

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

Figure 4-1: Jemena network maximum demand forecast comparison



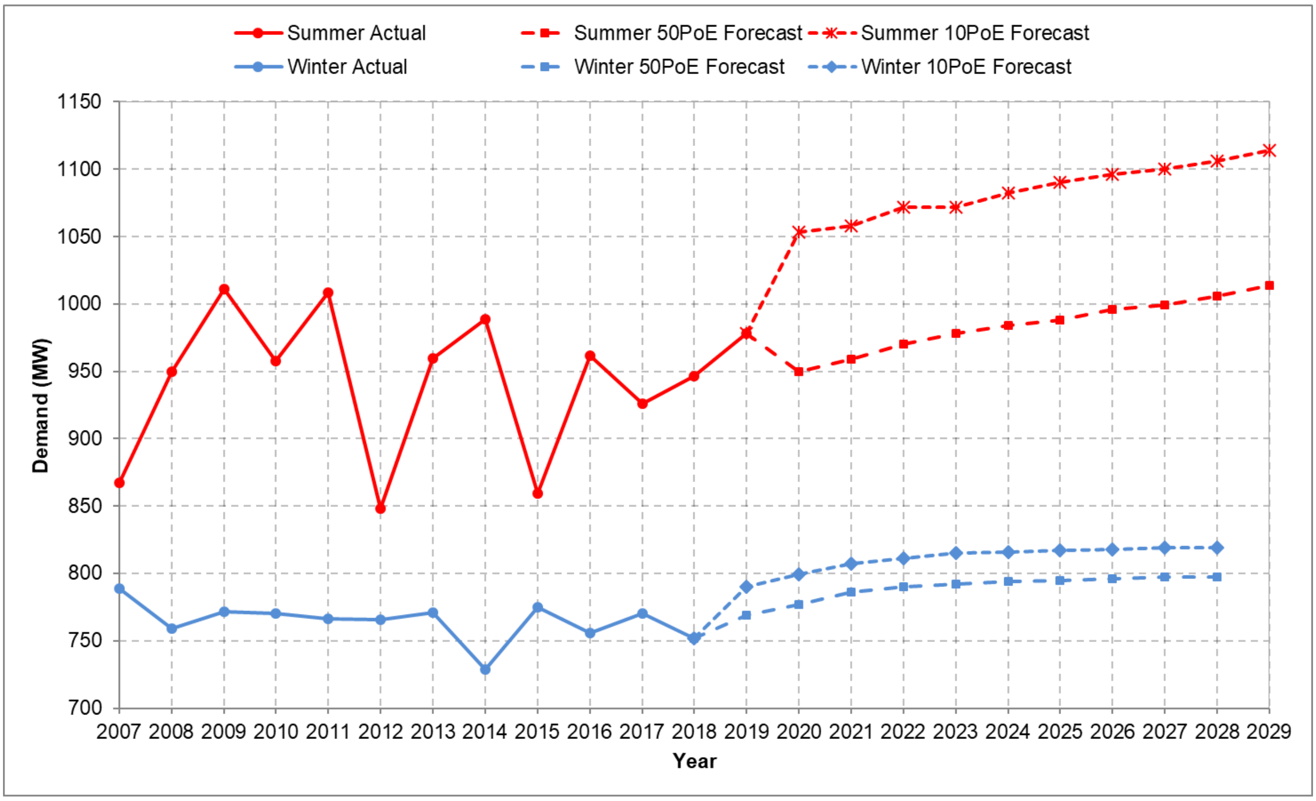
4.2 FORECAST DEMAND

As a whole, the growth in demand across Jemena's network is slowing, with the total network summer 50% POE maximum demand forecast to grow at an average rate of just 0.79% per annum over the next five years (2019-20 to 2024-25). This is largely being driven by a projected return to trend GDP growth and a stabilisation of electricity prices. Table 4–1presents the historical observed actual and ten year maximum demand forecasts for both 10% POE and 50% POE conditions in summer and winter (i.e. all Jemena network customers coincident load demand aggregated at the system level). The forecasts are also presented in Figure 4-2 along with the historical actual demand since 2005.

Table 4–1: Jemena network maximum demand forecast

Demand (MW)	Actual		Forecast										Average annual growth	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2020-2025	2020-2029
Summer (50PoE)	946.6	974.7	950	959	970	978	984	988	996	999	1006	1014	0.79%	0.73%
Winter (50PoE)	749.1	769	777	786	790	792	794	795	796	797	797		0.64%	0.40%
Summer (10PoE)	946.6	974.7	1053	1058	1072	1072	1082	1090	1096	1100	1106	1114	0.69%	0.63%
Winter (10PoE)	**749.1**	**790**	**799**	**807**	**811**	**815**	**816**	**817**	**818**	**819**	**819**		**0.65%**	**0.40%**

Figure 4-2: Jemena network historical and forecast maximum demand



Despite the general slowing in demand growth 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, such as Ford's manufacturing plant in Broadmeadows.

In general, areas where JEN expects a strong growth is 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 recent extension of the Urban Growth Boundary, JEN expects to see continued strong growth in the areas currently supplied by Kalkallo (maximum demand forecast to grow at 11.1% per annum over the next five years), Somerton (1.3%), Sydenham (1.8%), and Coolaroo (1.5%) zone substations.

Some pockets within established inner suburbs are also experiencing strong growth as a result of amendments to the planning schemes to 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, Essendon Airport and Melbourne International Airport. As a result, JEN is forecasting high growth in maximum demand for areas currently supplied by Fairfield (2.9%), Footscray East (2.9%), Yarraville (3.8%), and North Essendon (2.5%) zone substations.

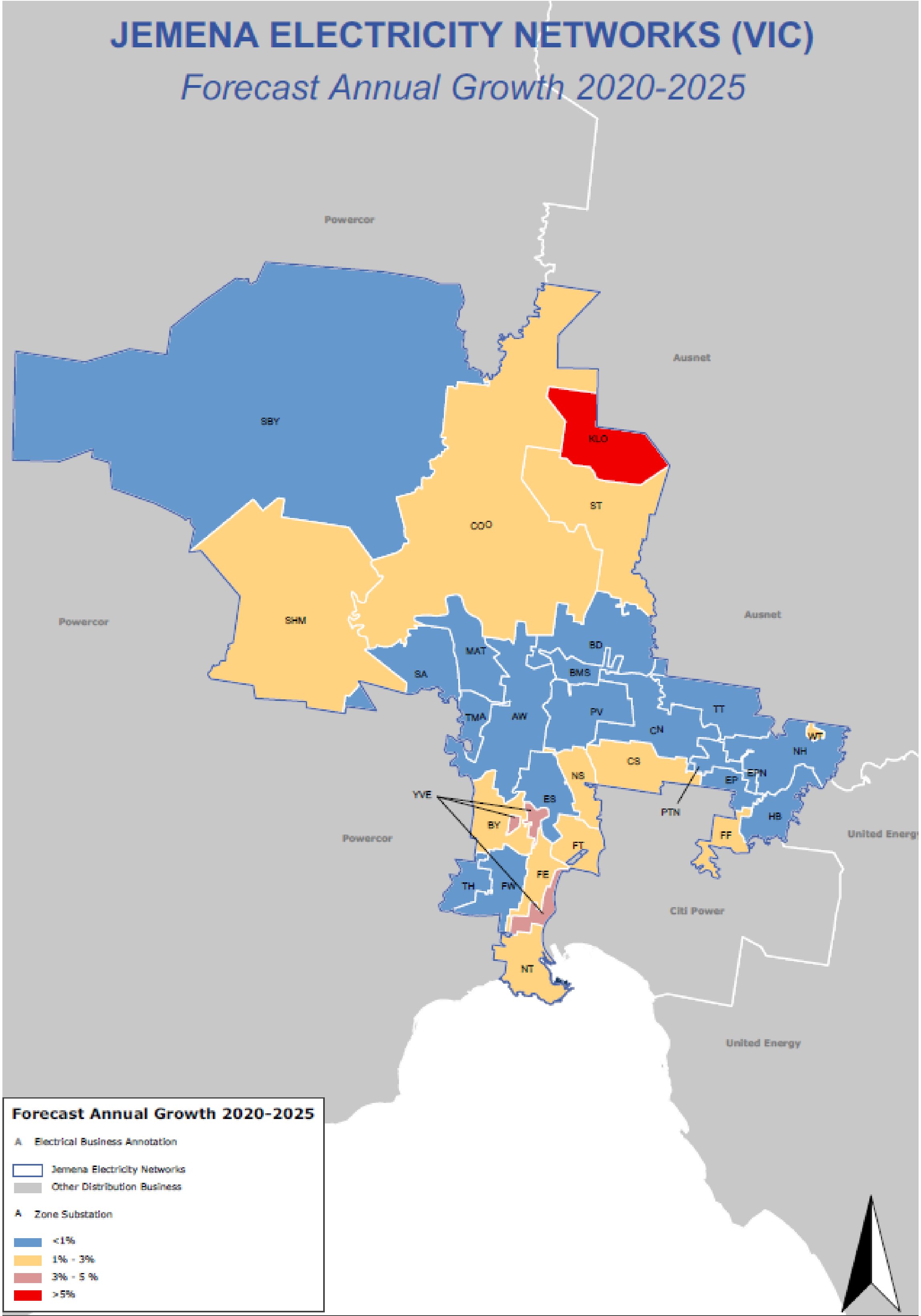
Other parts of the network, generally in the south, are expecting low growth or a decline in maximum demand over the forward planning period. Table 4–2 presents a summary of the expected growth/decline in maximum demand across Jemena's electricity network over the next five years. These growth areas are also presented geographically in Figure 4-3.

HV feeders which are forecast to exceed 100% utilisation by summer 2024-25 based on 10% POE forecasts are listed in Appendix A of this report.

Table 4–2: Supply area average annual growth over the next five years (2019-20 to 2024-25)

Season	Supply area average annual growth (2019-20 to 2024-25)			
	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	Kalkallo	Yarraville	Newport, Flemington, Somerton, Braybrook, Coolaroo, Coburg South, Sydenham, North Essendon, Footscray East, Watsonia and Fairfield	Australian Glass Manufacturer, Airport West, Broadmeadows, Melbourne Airport, Preston, Broadmeadows South, Coburg North, Essendon, Footscray West, Heidelberg, Melbourne Water, North Heidelberg, East Preston, Tullamarine, Pascoe Vale, St. Albans, Sunbury, Thomastown, Tottenham and Visy board

Figure 4-3: Forecast demand growth by zone substation supply area



4.3 REVIEW OF 2018 DEMAND FORECASTS

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

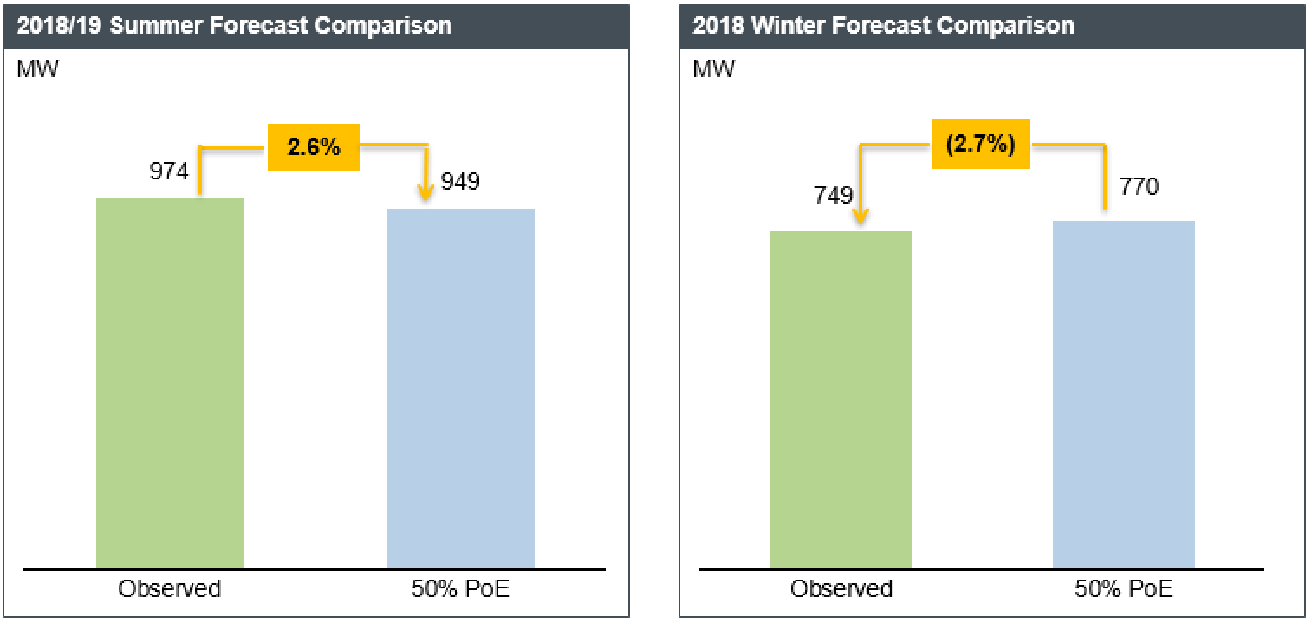
The observed 2019 summer and 2018 winter maximum demands generally agree favourably with Jemena's forecasts which were published in the 2018 DAPR.

4.3.1 NETWORK FORECAST

The observed network level maximum demand on the Jemena network was in line with Jemena's 50% POE forecast.

Maximum demand on Jemena network was 974 MW observed on the 25th January 2019 at 12.00pm. The average temperature on this day was 32.3 degree Celsius. Due to NEM limitation, Jemena was directed to shed 40MW of load on the day from 12:00pm to 2.00pm. The winter maximum demand was 749 MW observed on the 27th July 2018 at 6.00pm. Jemena summer demand was 2.6% above the forecasted 50% POE and the winter demand was 2.7% below the 50% POE forecast as shown in Figure 4-4.

Figure 4-4: JEN Observed Maximum Demand 2018/19



Contribution of Solar PV during summer maximum demand

The summer maximum demand on the Jemena network was observed during noon at 12.00pm. Of the approximately 125 MW of nameplate installed PV systems in the network, the contribution at the time of network maximum demand was about 92 MW.

4.3.2 TERMINAL STATION FORECAST

The observed terminal station maximum demand was within 8% of the 50% POE terminal station forecast for all terminal stations.

Table 4–3: Comparison of terminal station observed maximum demand to Jemena 2018 forecast

Terminal Station	50% POE (MW)	10% POE (MW)	Actual MD (MW)	Temp. Adjusted MD (MW)	% Difference (compared to 50% POE)
BLTS66	116.12	127.91	129.07	120.42	3.70%
BLTS22	2.96	2.96	3.71	3.71	N/A
BTS	51.36	58.19	58.76	54.60	6.32%
KTS B1-B2	220.73	246.61	227.89	217.07	-1.66%
KTS B3-B4	79.48	90.89	79.95	80.71	1.55%
SMTS	74.62	80.47	78.70	78.70	5.47%
TSTS	24.85	27.82	25.89	24.60	-1.01%
TTS B1-B2	96.57	106.37	107.55	103.58	7.26%
TTS B3-B4	246.89	267.80	250.60	257.62	4.35%
WMTS	64.93	71.86	63.90	65.54	0.95%

4.3.3 ZONE SUBSTATION FORECAST

As shown in Table 4–4 the observed zone substation maximum demand was within 10% of the 50% POE forecasts, for all zone substations except East Preston 22kV (EPN), Fairfield (FF), Footscray West (FW), Heidelberg (HB), Kalkallo (KLO), North Essendon (NS), North Heidelberg (NH), Sunbury (SBY), Tottenham (TH) and Yarraville (YVE).

Table 4–4: Comparison of zone substation observed maximum demand to Jemena 2018 forecast

Terminal Station	50% POE (MW)	10% POE (MW)	Actual MD (MW)	Temp. Adjusted MD (MW)	% Difference (compared to 50% POE)
Airport West	78.5	86.2	76.5	76.9	-2.06%
Braybrook	35.6	39.6	37.5	36.6	2.84%
Broadmeadows	81.0	88.3	76.3	79.5	-1.93%
Broadmeadows South	30.1	32.8	29.0	30.3	0.59%
Coburg North	60.8	67.7	65.0	60.5	-0.39%
Coburg South	50.2	56.4	44.4	54.0	7.64%
Coolaroo	39.9	45.4	42.3	42.6	6.72%
East Preston-A	8.9	9.3	9.6	9.6	8.32%
East Preston-B	13.2	14.2	14.2	14.3	8.07%
East Preston-22kV	19.2	21.4	23.4	24.0	25.28%
Essendon	41.9	47.0	41.7	40.0	-4.49%
Fairfield	21.4	23.7	23.0	23.6	10.17%
Flemington	35.3	38.9	34.2	33.0	-6.48%
Footscray East	35.6	38.8	33.7	37.1	4.17%
Footscray West	43.6	47.4	37.7	37.8	-13.28%
Heidelberg	24.9	27.6	26.4	28.0	12.61%
Kalkallo[10]	8.1	8.7	10.6	10.6	32.09%
Newport	34.7	38.6	37.6	38.1	9.94%
North Essendon	30.1	35.3	36.5	33.3	10.51%
North Heidelberg	53.3	59.4	61.2	62.4	17.01%
Pascoe Vale	35.1	40.8	37.5	37.9	8.12%
Somerton	69.0	74.5	72.1	75.0	8.71%
Sunbury	36.8	40.9	41.4	41.7	13.52%
Sydenham	39.1	43.1	41.1	41.3	5.74%
Thomastown	30.2	34.1	32.3	30.4	0.57%
Tottenham	22.0	23.2	27.8	28.8	30.60%
Tullamarine	22.9	25.1	20.5	21.7	-5.22%
Yarraville	28.8	31.7	39.1	32.8	13.64%

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

4.4 NETWORK UTILISATION

4.4.1 ZONE SUBSTATIONS

Maximum demand on the Jemena network during 2018/19 summer was observed on 25th Janurary 2019 at 12:00pm. Figure 4-5 and Figure 4-6 below outlay the zone substation utilisation under N secure and N-1 ratings during the maximum demand day.

The load at Footscray East (FE) zone substation exceeded its ‘N secure’ rating on the maximum demand day. Operational action was used to ensure that no load reduction was required and the assets’ loading remained within their capabilities. At FE this involved load transfers to shift demand away from FE zone sustation using emergency transfer capacity.

A number of zone substation operated above their N-1 ratings during this maximum demand event as shown in Figure 4-6.

4.4.2 HV FEEDERS

Figure 4-7 shows the JEN network HV feeders that operated above 80% utilisation during summer 2018/19. Loading on these feeders will continue to be monitored together with contingency plans in place during summer 2019/20 in order to avoid disruption on the network.

Figure 4-5: Jemena network zone substation utilisation (N secure rating)

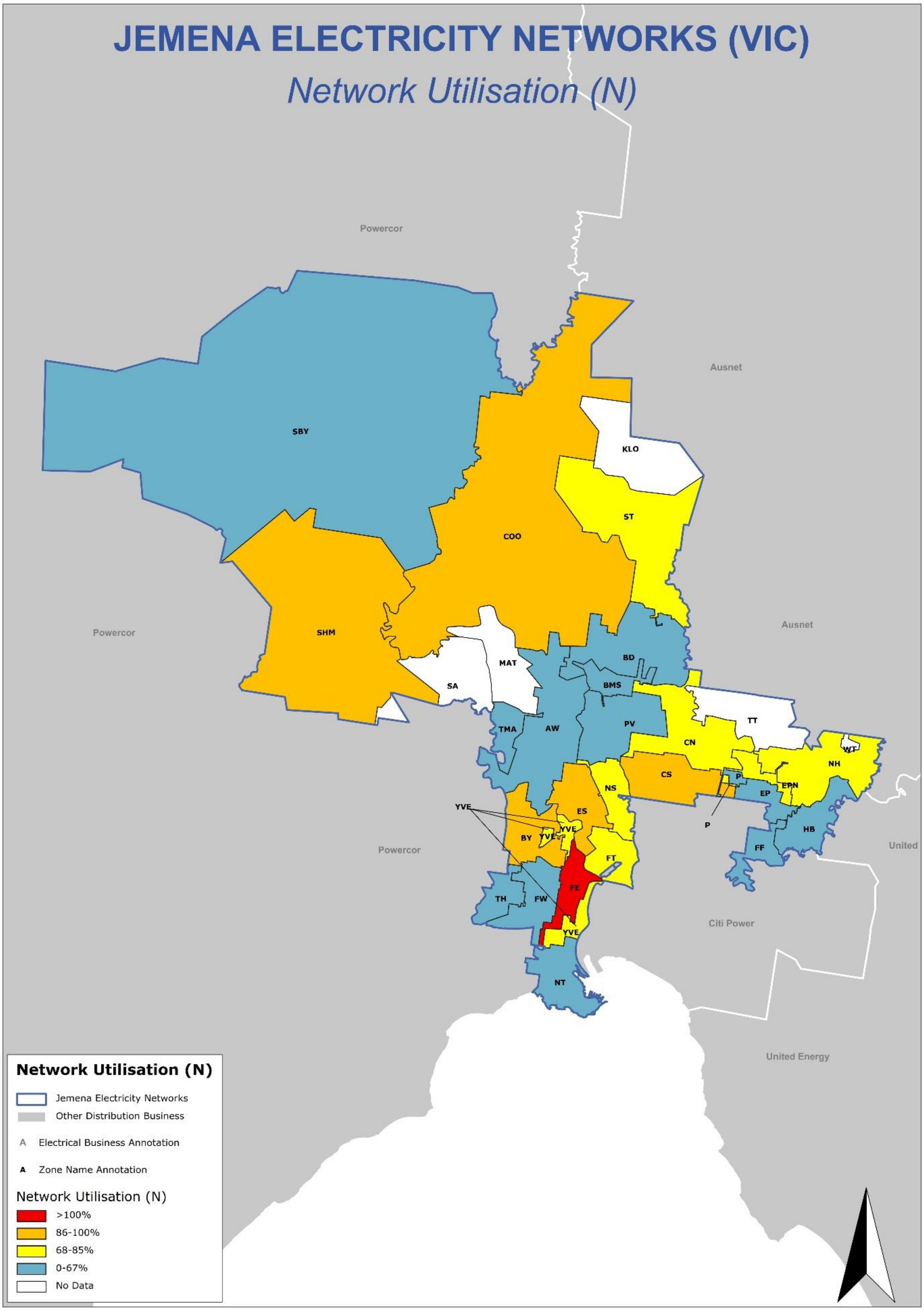


Figure 4-6: JEN zone substation utilisation (N-1 rating)

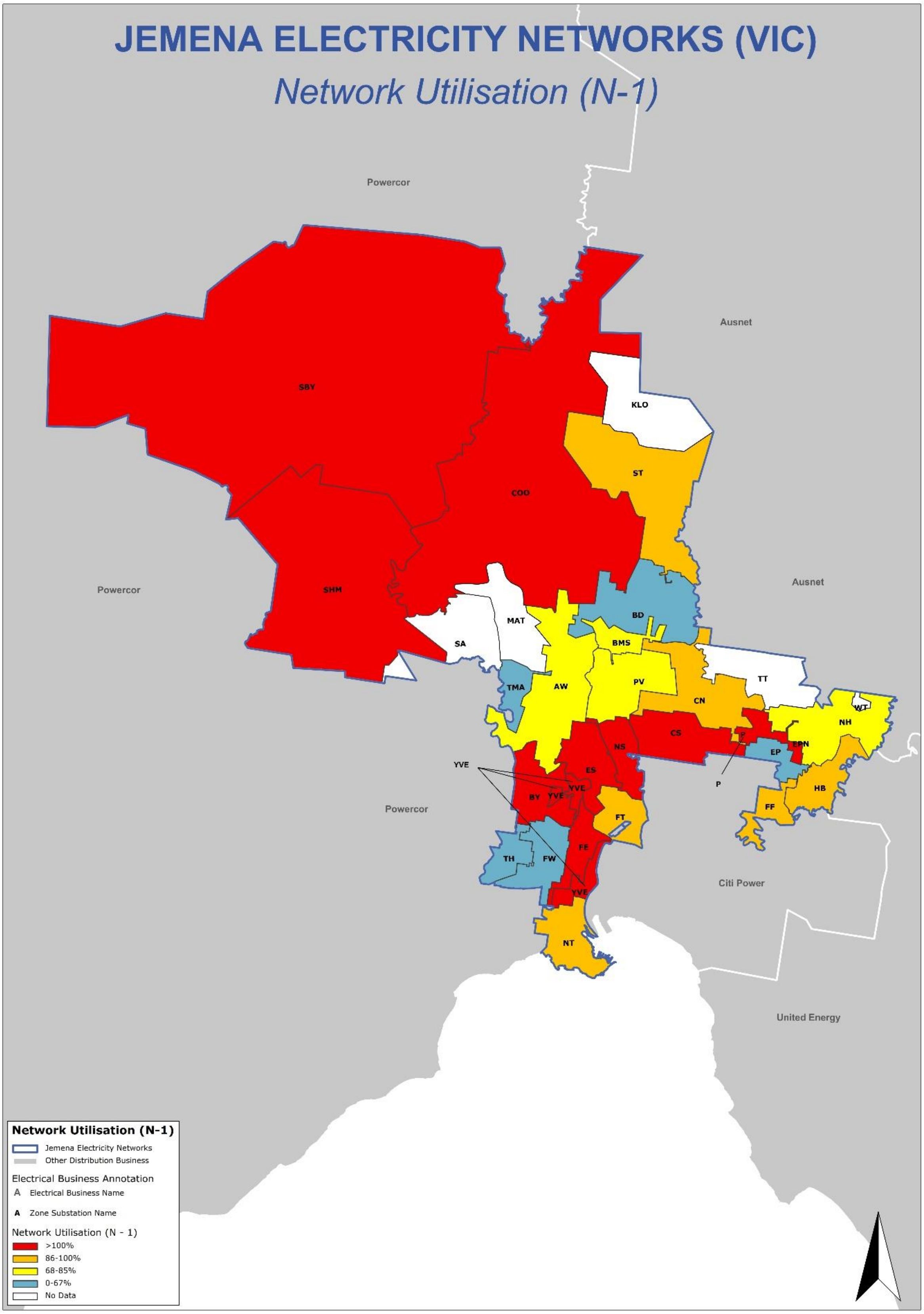
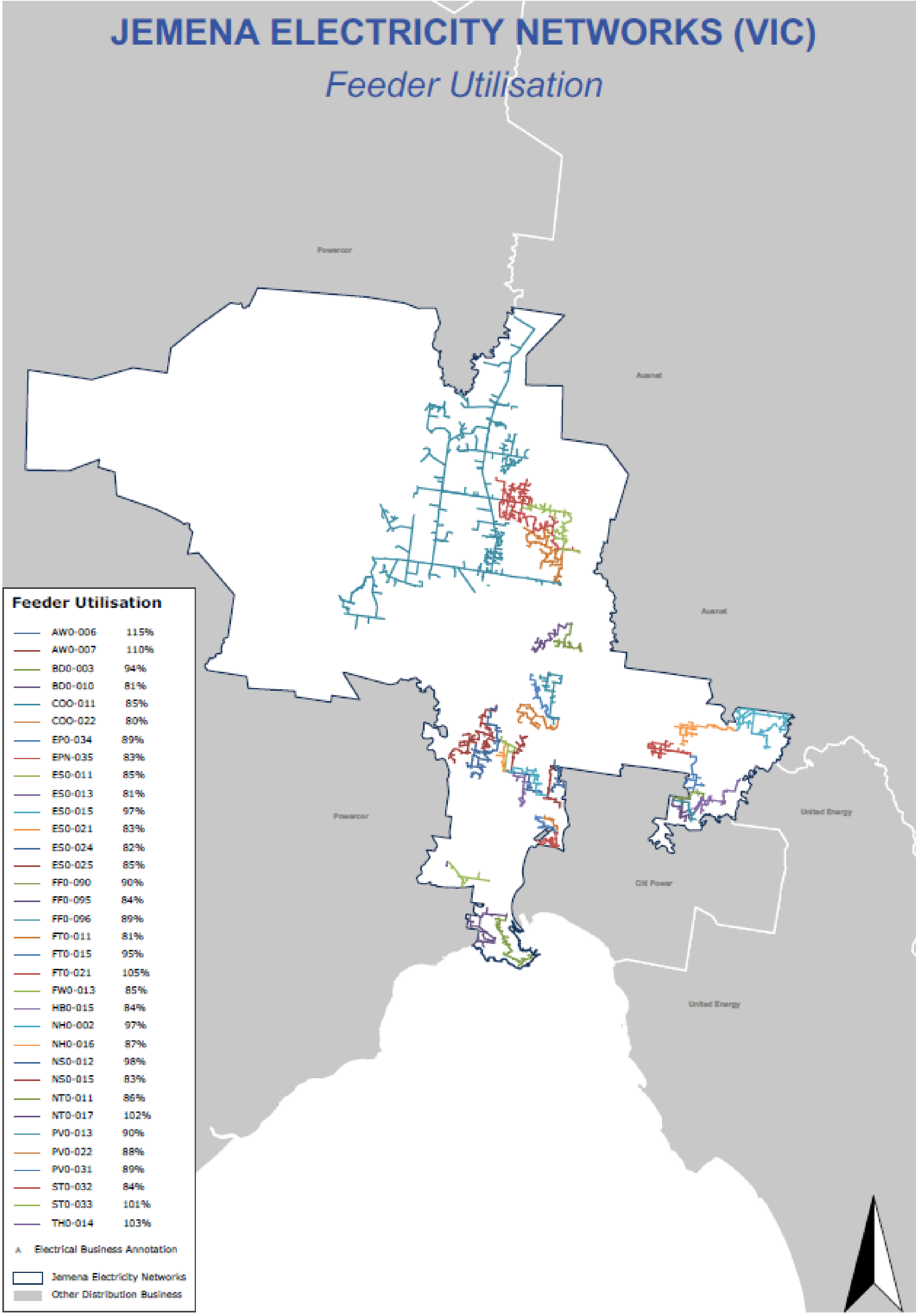


Figure 4-7: JEN HV feeder utilisation



5. NETWORK DEVELOPMENT

This section outlines 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 (2020 to 2024). These existing and emerging limitations can be a result of asset condition, thermal and fault level capacity, or power quality issues.

To facilitate non-network service provider solutions, the expected impact of identified limitations are 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 Jemena 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 $2019, 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 outlined in Sections 5.111 and 5.122. This development plan is based on current network conditions and Jemena's 2019 Load Demand Forecasts Report. Other than Table 5–1 which presents 2020 committed projects (or about to be committed), development proposals are uncommitted and still subject to Jemena's project approvals process and procurement of appropriate funding. Any party considering an investment (or potential deferral of a proposed investment) based on this development plan should first consult Jemena 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 2020. Table 5–2 through to Table 5–5 presents Jemena's proposed network augmentation plans for the 2021-2024 period.

Figure 5-1 shows Jemena's electricity network, including terminal station supply points, sub-transmission lines and zone substations, and highlights major augmentation project locations based on the Project Reference Numbers presented in Table 5–1 through to Table 5–5. 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: 2020 network augmentation plans

Network limitation	Preferred network solution	Project reference number (see Figure 5–1 for locations)	Section reference
AW feeders capacity constraint	Reconfigure feeder - AW Feeders	1	5.11.1
P and EP asset condition and CS thermal capacity constraint	Stage 6 Preston area conversion (establish PTN)	2	5.11.21
KTS-BY-ES 66 kV loop thermal capacity constraint	Augment KTS-BY-ES 66 kV loop	3	5.12.6
KTS-MAT-AW-PV 66 kV loop thermal capacity	Rearrange KTS-MAT-AW-PV-KTS 66 kV split loop	4	5.12.7
COO & ST capacity constraint	Augment ST feeders	5	5.11.7
SBY-32 and SBY-11 back up supply	Establish tie-line between SBY32 and SBY11	6	5.11.23

Table 5–2: 2021 network augmentation plans

Network limitation	Preferred network solution	Project reference number (see Figure 5–1 for locations)	Section reference
CS-05 thermal capacity constraint	Augment feeder CS-05	7	5.11.6
EP asset condition and thermal capacity	Stage 5 East Preston area conversion	8	5.11.8
YVE feeder capacity constraint	Reconfigure Feeder YVE-11	9	5.11.13, 5.11.29
ES-13, ES-15 and ES-24 thermal capacity constraint	Reconfigure feeder ES-23	10	5.11.10

Table 5–3: 2022 network augmentation plans

Network limitation	Preferred network solution	Project reference number (see Figure 5–1 for locations)	Section reference
BTS-NS-BTS 22 kV loop thermal capacity	Augment BTS-NS 22 kV loop	11	5.12.5

KLO-13 capacity constraint	Reconfigure KLO-21	12	5.11.16
NT feeder capacity constraint	Augment Feeder NT0-011	13	5.11.17
EP asset condition and thermal capacity	Stage 6 East Preston area conversion	14	5.11.8
Safety risk associated high bushfire risk area	Install REFCL at COO and COO REFCL Feeder Works	15	5.11.7

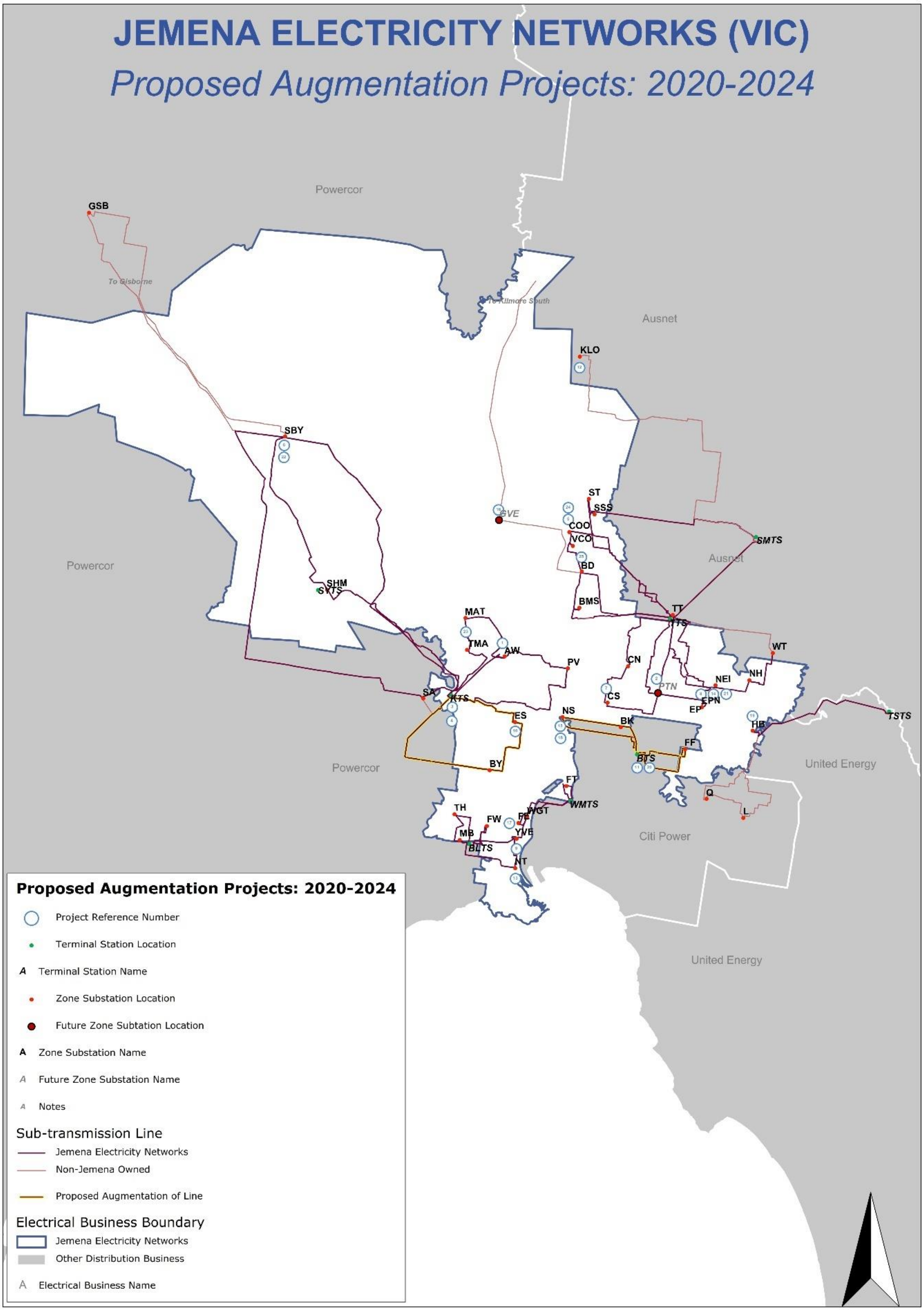
Table 5–4: 2023 network augmentation plans

Network limitation	Preferred network solution	Project reference number (see Figure 5–1 for locations)	Section reference
Safety risk associated high bushfire risk area	Establish new Greenvale zone substation	16	5.11.7
FE-06 thermal capacity constraint	Augment feeder FE-06 and rebalance the load between FE-06 and YVE feeders	17	5.11.13
NS-18 thermal capacity	Augment feeder NS-18	18	5.11.18
HB-14, HB-15 and HB-22 thermal capacity	Install a new HB feeder (HB-21)	19	5.11.15
BTS-FF sub-transmission loop thermal capacity constraint	Augment BTS-FF loop	20	5.12.4

Table 5–5: 2024 network augmentation plans

Network limitation	Preferred network solution	Project reference number (see Figure 5–1 for locations)	Section reference
EP asset condition and thermal capacity	Stage 7 East Preston area conversion	21	5.11.8
SBY feeder thermal capacity constraint	Reconfigure feeder SBY-024	22	5.11.23
AW-06 and AW-07 thermal capacity	Establish new feeder TMA-15	23	5.11.27
COO-22 and ST-32 capacity constraint	Reconfigure feeders COO-22, ST-31 and ST-32	24	5.11.7, 5.11.22
BD-08, BD-13 and ST-34 feeder thermal capacity constraint	Reconfigure BD and ST feeders	25	5.11.3

Figure 5-1: Jemena electricity network (December 2019) and major proposed augmentation projects



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. Other than replacement projects in Table 5–6 which presents 2020 committed projects (or about to be committed), the asset replacement proposals are uncommitted and still subject to Jemena'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 Jemena for specific, detailed, and up-to-date network asset information.

Table 5–6 lists the committed (or about to be committed) network replacement projects for 2020.

Table 5–7 through to

Table 5–**10** present Jemena's proposed network asset replacement plans for the 2021-2024 period.

Figure 5-2 shows Jemena's electricity network, including terminal station supply points, sub-transmission lines and zone substations, and highlights major replacement project locations based on the Project Reference Numbers presented in Table 5–6 through to

Table 5–**10**.

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: 2020 network asset replacement plans

Network limitation	Preferred network solution	Project reference number (See Figure 5-2 for locations)	Section reference
FE CB asset condition	Replace 66 kV circuit breakers at FE	26	5.11.13
HB CB asset condition	Replace 66 kV circuit breaker at HB	27	5.11.15

Table 5–7: 2021 network asset replacement plans

Network limitation	Preferred network solution	Project reference number (See Figure 5-2 for locations)	Section reference
FW CB asset condition	Replace 66 kV circuit breakers at FW	28	5.11.14
FE switchgear and relay asset condition	Replace 22 kV switchgear at FE	29	5.11.13
FE & FW capacitor bank asset condition	Replace capacitor bank CB's - FE & FW	30	5.11.13, 5.11.14
BY relay asset condition	Replace BY 22 kV feeder relays	31	

Table 5–8: 2022 network asset replacement plans

Network limitation	Preferred network solution	Project reference number (See Figure 5-2 for locations)	Section reference
FW switchgear and relay asset condition	Replace 22 kV switchgear and relays at FW	32	5.11.14
HB transformer asset condition	Replace HB transformers	33	5.11.15
BD transformer asset condition	Replace BD transformer	34	5.11.3

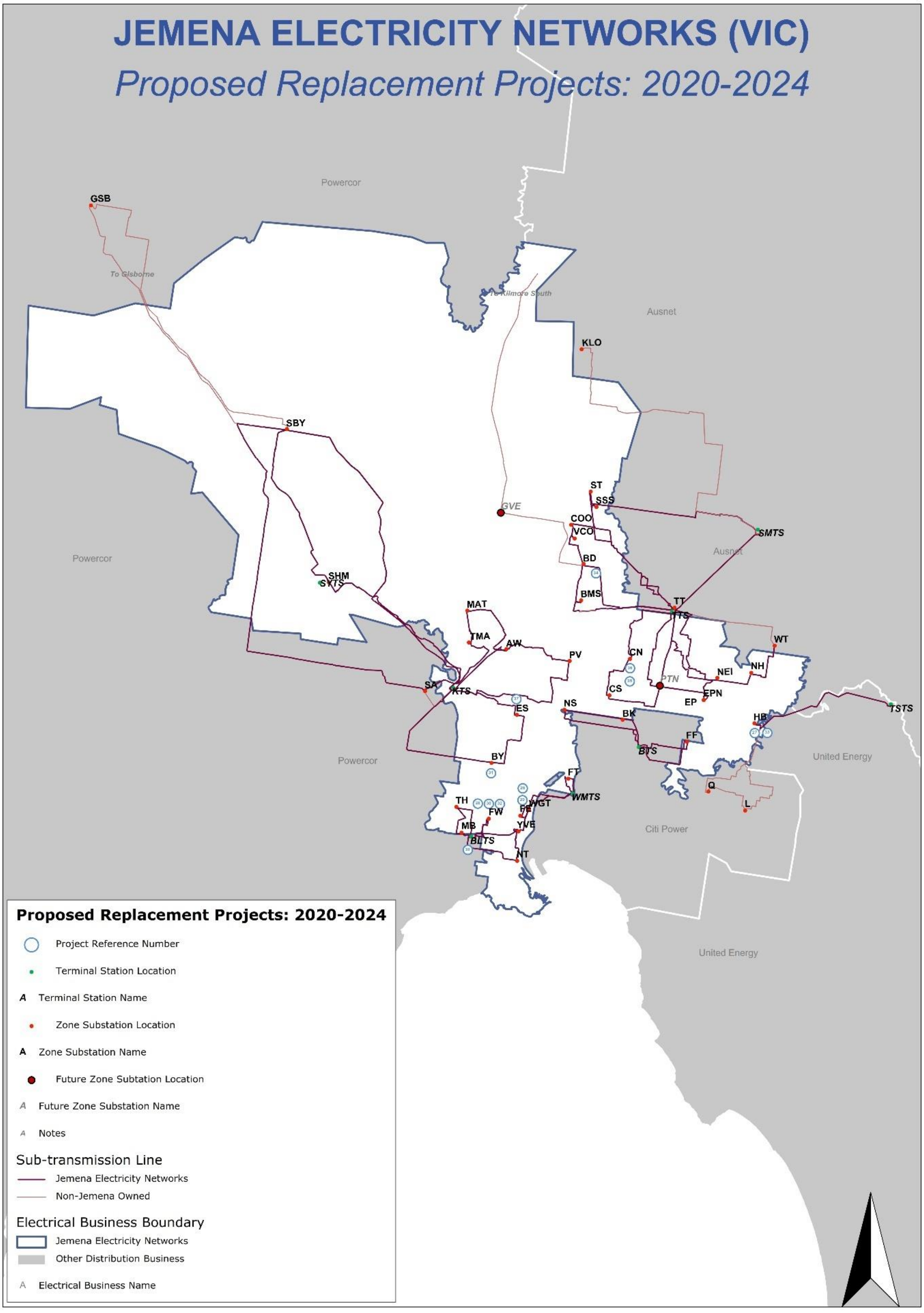
Table 5–9: 2023 network asset replacement plans

Network limitation	Preferred network solution	Project reference number (See Figure 5-2 for locations)	Section reference
CN 66kV CB asset condition	Replace 66 kV 1-2 bus-tie circuit breaker at CN	35	5.11.5
CN switchgear and relay asset condition	Replace 22 kV switchgear and relays at CN	36	5.11.5
ES & CN capacitor bank asset condition	Replace capacitor bank CB's - ES & CN	37	5.11.10, 5.11.5

Table 5–10: 2024 network asset replacement plans

Network limitation	Preferred network solution	Project reference number (See Figure 5-2 for locations)	Section reference
BLTS 22 kV switchgear asset condition	Replace 22 kV switchgear - BLTS	38	5.11.29

Figure 5-2: Jemena electricity network (December 2019) and major proposed replacement projects



5.3 CHANGES SINCE THE 2018 REPORT

In the preceding 12 months, Jemena has completed the following bulk relay replacement project:

- Replace relays at Broadmeadows (BD) Zone Substation.

In addition, the following major network upgrades (which are committed projects) are expected to be completed in 2020:

- Stage 6 Preston area conversion – rebuilt P with a new 66/22 kV Preston (PTN) zone substation consisting of two 66/22kV 20/33 MVA transformers on the existing site;
- Replace the existing two 66/11 kV 20/27 MVA transformers at Essendon (ES) zone substation with two new 66/11 kV 20/33 MVA transformers;
- Replace the existing two 22/6.6 kV 10/13.5 MVA transformers at Fairfield (FF) zone substation with two new 22/11/6.6 kV 12/18 MVA dual secondary winding transformers;
- Rearrange the KTS-MAT-AW-PV-KTS 66 kV split loop; and
- PV-11 kV feeders upgrade and reconfigurations.

A number of network augmentation projects have been deferred to beyond 2024 as analysis has determined they are not yet economically justified, however these projects will continue to be reviewed annually:

- Augment feeder SBY-23 and install a voltage regulator;.
- Establish new feeder FT-25;
- Augment steel section of feeder SBY-24;.
- Reconfigure feeders from BY, FW and TH; and
- Augment feeder NS-15.

5.4 GROUPED NETWORK ASSET REPLACEMENT PROGRAMS

This section presents an outline of the ongoing asset replacement programs that Jemena has in place for assets which 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 Jemena Electricity Network (JEN) and are manufactured from various materials including wood, concrete and steel constructions. Jemena'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 Jemena's regulatory obligations.

Jemena employs a condition based approach to the replacement and refurbishment of poles, but use a combination of age and condition to forecast 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.

The forecast replacement volumes are based on Condition Based Risk Management (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 Asset Class Strategy (ACS) .

5.4.2 POLE TOP STRUCTURES

Pole top structures include cross-arms, insulators, 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, conductor, 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 is modelling is used to determine the replacement volumes. Modelling results are detailed in Asset Class Strategy (ACS).

5.4.3 DISTRIBUTION EQUIPMENT

Distribution equipment consist 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 replacement 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 had reached the end of life. In general, 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 is modelling is used to determine the replacement volumes. Modelling results are detailed in the associated Asset Class Strategy (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 sub-transmission 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 for Jemena.

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 impact 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 service to neutral earth impedances to be less than one (1) ohm. This impedance is measured using metering data analytics on a daily basis.

Neutral Supply Test (NST) will continue for customers who do not have AIM metering on a ten (10) year cycle.

Routine inspection and testing of services is mandated by the Electricity Safety (Bushfire Mitigation) Regulations 2013. Defective services identified during inspection and testing are replaced.

In addition to this routine replacement, Jemena is undertaking a program to replace non-standard LV overhead services. The program commenced in 2010. The Electricity Safety (Installations) Regulations 2009 define ground clearance requirements for low voltage aerial lines. Complying with these regulations is now included in Jemena'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 pose a threat to both reliability of supply and public safety.

5.4.7 EARTHING

Distribution earthing

In 2015, Jemena completed a HV earth testing program in non CMEN (Common Multiple Earth Neutral) areas to comply with the Jemena Electricity Networks Safety Management Scheme (ESMS). The resistance of all non CMEN HV earths on the JEN network were measured and recorded in accordance with the Electricity Safety (Network Assets) Regulations 1999 and now Jemena's Electricity Safety Management Scheme (ESMS).

The highest-priority HV earths were addressed in 2017 as Stage 1 of a rectification gram. The remaining HV earths that still require rectification to bring the earth resistance to an acceptable level in non CMEN Areas will be addressed as an ongoing project.

Zone substation earthing

Testing of zone substation earth grids is undertaken at 10 yearly intervals to ensure they continue to comply with safety criteria. Sample inspections of underground conductors & 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 condition 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 are replaced based on condition. If the protection relay is not fit for service based on condition or exhibiting symptoms of aged related deterioration, it will be replaced. This option is considered the most cost effective option as it maximise the assets investment cost. 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, Jemena developed a strategy to replace the existing relays to ensure ongoing reliability of supply to its customers. In the forward planning period, Jemena will be undertaking bulk relay replacements at Braybrook (BY) in 2021, Footscray West (FW) Zone Substation in 2022, Courg North (CN) Zone Substation in 2023, and Coburh South (CS) Zone Substations in 2024/25.

Power quality meters

Jemena'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. Within end of feeder distribution substations, the power quality meters are connected directly to the low voltage network without voltage transformers. Monitoring of load current is not implemented at the load end of feeders due to limited availability of current transformers in distribution substations.

The fleet of power quality meters is aging, with many nearing 20 years of age. 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, Jemena has initiated a planned replacement program in which all of the zone substation power quality meters will be replaced by modern devices during the forward planning period. There are also plans to replace the end of feeder monitors once the zone substation replacement program is complete.

Battery banks and chargers

DC supply system is one of the most critical asset in a zone substation. The DC supply system consisting mainly of battery banks and battery chargers are 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 charger or due to interruption of AC supply input to charger, the battery bank must seamlessly support the zone substation DC loads for a designated period of time.

These assets are at a risk of failure due to age related deterioration and irreversible temperature related thermal degradation. In the forward planning period, Jemena plans to undertake replacement of batteries and chargers at the following zone subsations which have reached their end of life as listed below.

- Pascoe Vale (PV) and Newport (NT) in 2021;
- Sydenham (SHM) and Somerton Switching Station (SSS) in 2022;
- Somerton (ST) and Tottenham (TH) in 2023; and
- Nilsens Electrical Industies (NEI), Visy Coolaroo (VCO) and Yarraville (YVE) in 2024.

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 condition, so that condition based replacement can be planned as required. This program has been employed to test VT's and CT's over 40 years old.

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

Insulators

Arcing discharge and surface tracking has been witnessed on the 66 kV brown pin insulators, warranting their replacement. These insulators are installed at Footscray East (FE) and at Heidelberg (HB) Zone Substations. There has been a number of failures of this type of insulator across other distribution networks nationally. These replacements will be combined larger switchgear replacement projects at the respective zone substations.

5.4.10 COMMUNICATIONS AND SCADA

Communication and Field SCADA assets

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

The replacement of communication and field SCADA assets are 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	70	20
Other network devices - Routers and Firewall	6	10
MDS iNet radio transceivers	194	17
3G modems	75	17
Copper cables	~16 km in service Cu cable	50
Fibre optic cable	~298 km	50
GPS Clock	26	20
Remote Terminal Units (RTU)	30	20
Multiplexers	90	20
Voice Frequency (VF)	9 VF circuits, 18 cards	40

Asset Type	Volume	Asset Life Expectancy (Years)
AMI Relays	337	15
AMI Access Point	111	10
AMI Batteries	448	5

SCADA

The reliability of the Jemena SCADA Distribution Management Systems (DMS) and Outage Management Systems (OMS) are critical to the safe and reliable supply of energy to JEN customers. A number of these core systems have reached their end of useful life and are increasing the operational risk to the electricity networks. Retaining the current control system poses an increasing risk of failure and an inability to recover from a system failure.

The need to replace end of life systems provided Jemena with the opportunity to consolidate control systems from multiple vendors to a single platform that is modular, supported and scalable to meet the future needs of Jemena. The SCADA DMS OMS upgrade program was accepted by the AER as part of the 2016 JEN EDPR submission. The programs of works started in 2017 and will run to the first quarter of 2020.

5.5 NETWORK LIMITATIONS

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[11]. 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)[12] which includes information including:

- 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.

In 2019, Jemena has collaborated with Energy Networks Australia to update the existing Network Opportunity Maps (NOM) platform[13] to meet the requirements of clause 5.13.3. The resulting Distribution System Limitation Report is published along with historic load traces on the Jemena website[14]. Ultimately this data will be imported into the NOM to provide a visual representation of the identified constraints.

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

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

13 http://www.energynetworks.com.au/network-opportunity-maps

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

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 2019 Transmission Connection Planning Report (TCPR), for Jemena's five-year forward planning period.

Table 5–12: Jemena Connection Points

Connection Point	2018 TCPR Outcome
Brunswick Terminal Station (22 kV)	No augmentation of capacity is required.
Brooklyn Terminal Station (22 kV)	No augmentation of capacity is required.
Keilor Terminal Station	No augmentation of capacity is required.
South Morang Terminal Station	No augmentation of capacity is required.
Templestowe Terminal Station	No augmentation of capacity is required.
Thomastown Terminal Station	No augmentation of capacity is required.
West Melbourne Terminal Station	No augmentation of capacity is required.

There have been no material changes to joint planning undertaken between Jemena 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 sub-transmission assets shared by Jemena and surrounding DNSPs, which are listed in Table 2–1.

Recognising the interrelationships between Jemena's Coolaroo (COO) and AusNet Services Kalkallo (KLO) zone substations, in the preceding year Jemena and AusNet Services engaged consultants WSP to assist in a joint planning exercise to examine a number of 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 which did not require any exemptions from the requirements of the Electricity Safety (Bushfire Mitigation) Regulations. This option requires augmentation of the Jemena Electricity Network including installing REFCL at COO, network hardening and balancing on COO and KLO feeders, and constructing a new REFCL zone substation at Greenvale (GVE). Refer to section 5.10 for more information.

5.7 SUMMARY OF RIT-D APPLICATIONS

Jemena has completed three replacement Regulatory Investment Tests for Distribution (RIT-Ds) since publication of the 2018 DAPR. A fourth replacement RIT-D had completed Stage 1 of the RIT-D process with Stage 2 currently in progress. Jemena also intends to commence an additional five replacement and three augmentation RIT-Ds assessment within the forward planning period (2020-2024).

The completed replacement RIT-Ds are:

- East Preston (EP) conversion Stage 5;
- Footscray East Zone Substation (FE) switchgear condition; and
- Heidelberg Zone Substation (HB) transformer condition.

The replacement RIT-D which is in progress:

- Footscray West Zone Substation (FW) switchgear and relay condition.

Jemena intends on commencing the following five replacement projects RIT-Ds in the forward planning period.

- East Preston (EP) conversion Stage 6, Stage 7 and Stage 8 (see section 5.11.8);
- Coburg North Zone Substation (CN) switchgear and relay condition (see section 5.11.5); and
- Coburg South Zone Substation (CS) switchgear and relay condition (see section 5.11.6).

Jemena intends on commencing the following two augmentation projects RIT-Ds in the forward planning period.

- Brunswick Terminal Station - North Essendon Zone Substation 22 kV sub-transmission loop capacity constraint (see section 5.12.5);
- Brunswick Terminal Station - Fairfield Zone Substation 22 kV sub-transmission loop capacity constraint (see section 5.12.4); and
- Rapid Earth Fault Current Limiter (REFCL) (see section 5.10)

5.7.1 EAST PRESTON (EP) CONVERSION STAGE 5

Identified need

East Preston Zone Substation (EP) comprises two 66/6.6 kV 20/27 MVA transformers, two 66/6.6 kV 10/13.5 MVA transformers and six 6.6 kV buses supplying fourteen 6.6 kV distribution feeders. The substation is electrically split between two switch houses, EP-A and EP-B. EP supplies areas of Preston, East Preston and Heidelberg West. The surrounding zone substations CN, CS and NH all operate at 22 kV.

The drivers of the identified investment need were:

- To protect power sector workers and members of the public from harm caused by equipment failure due to the deteriorated condition of assets at EP;
- To maintain a reliable power supply to the residences and businesses that are dependent on the supply from EP distribution network; and

- To support growth aspirations for the wider Preston area through reducing cost and complexity of connection for new residences and new businesses.

Options considered in RIT-D

The credible options which were considered in Stage 2 of the East Preston Conversion Stage 5 RIT-D are:

- Option 1: Stopping the Preston Conversion Program at the end of P Stage 6 and running the remaining 6.6 kV network to failure;
- Option 2: Stop Preston Conversion Program at end of P Stage 6, and undertake like for like replacement of remaining network; and
- Option 3: Continue the Preston Conversion Program.

RIT-D status

On 27 November 2018, Jemena published Stage 2 of the East Preston Conversion Stage 5 RIT-D, the Draft Project Assessment Report (DPAR). This report assessed possible options for economically mitigating the supply risks at EP 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.

RIT-D outcome

The East Preston Conversion Stage 5 options analysis identified that:

- Option 3, Continue the Preston Conversion Program, by proceeding with the next stage (EP Conversion Stage 5) as the preferred network option; and
- There were no credible non-network options, or combinations of non-network options with network options which could defer the need for the preferred network augmentation.

It should be noted that Option 3 (the preferred option) was tested under a range of sensitivities including variations in costs, value of customer reliability and bus failure impacts. In each Case Option 3 was confirmed to provide positive economic benefits, and be the highest ranked option.

It is also noted that Option 3 (the preferred option) is expected to generate additional benefits which were not quantified as part of this appraisal, and further support the case for prompt investment:

- Safety - as is common practice within the electricity sector, Jemena did not undertake a quantified assessment of the safety benefits of each option, which are considered likely to be significant.
- Secondary asset failure - the supply risk associated with the replacement of secondary asset such as relays was also not quantified, as it was considered second order, and unlikely to affect the ranking of options.
- Reduction in network losses - the reduction in network losses associated with converting the old 6.6 kV network and to a 22 kV network was not quantified. This benefit is also expected to be significant, but was not quantified given the proportionality test – the case for investment was made without consideration of these benefits.

Jemena has proceeded with the business case approval for this option with the works for this stage planned for completion by June 2021.

The estimated construction timetable is as follows:

- Business case approval: Janurary 2020 (commenced);
- Distribution survey complete: Feburary 2020;
- Distribution design complete: April 2020;
- Construction start: June 2020; and
- Commissioning complete: June 2021.

5.7.2 FOOTSCRAY EAST ZONE SUBSTATION (FE) SWITCHGEAR CONDITION

Identified need

The condition of the 22 kV switchgear at Footscray East (FE) Zone Substation is deteriorating. The switchgear is non compliant with current arc fault containment standards and the switchgear condition has degraded to a point where employee safety, reliability and security of customer supply will be affected. Recent testing of the switchgear has indicated decreased insulation resistance and polarisation index from previous testing in 2008. The magnitude of the partial discharge (PD) above the service voltage level has also increased on all phases from the previous measurements in 2008 on the no.1 22 kV bus. The 66 kV bus tie circuit breaker (CB) represents a family of breakers with a history of failure. Catastrophic failure of the primary insulation risks the safety of employees and security of customer supply.

RIT-D status

On 12 February 2019, Jemena published Stage 1 of the FE switchgear condition RIT-D, the Non-Network Options Screening Report (NNOSR). This report assessed possible non-network options for economically mitigating the identified risks at FE. The NNOSR conclusion is that none of the potential non-network options investigated represent technically or commercially feasible alternatives, nor could any combination of non-network options adequately address the identified need. Jemena did not receive any submissions on this NNOSR, therefore the following section constitutes the (Final Project Assessment Report) FPAR for this RIT-D project. It should be noted as the preferred network option is less than $10 million, therefore Jemena is not required to publish a draft project assessment report per clause 5.17.4(n) of the NER.

Network options consider

The credible network options which were assessed to manage the risk associated with the aging 22 kV buses and associated switchgear at FE were:

- Option 1: Do nothing, run to fail;
- Option 2: Increased maintenance and monitoring;
- Option 3: Full Load Transfer;
- Option 4: 22 kV and 66 kV switchgear refurbishment; and
- Option 5: Replace 22 kV buses and associated 66 kV switchgear.

Project outcome

Jemena has identified that Option 5 to replace the buses and associated switchgear at FE Zone Substation with modern equivalents will address the project identified needs and is the option that maximises the net market benefits to consumers.

Based on this analysis, Option 5 is about to be a committed project which is due for completion in 2021.

The estimated construction timetable is as follows:

- Business case approval: December 2019 (in progress);
- Primary design complete: April 2020;
- Secondary design complete: June 2020;
- Construction start: August 2020; and
- Commissioning complete: November 2021.

5.7.3 HEIDELBERG ZONE SUBSTATION (HB) TRANSFORMER CONDITION

Identified need

Zone substation Heidelberg (HB) has two 20/30 MVA power transformers operating at 66/11 kV and seven 11 kV feeders supplying approximately 9,000 customers. The two power transformers are manufactured by Wilson Transformer Company (WTC) and over 53 years old.

The cellulose in the transformers' paper insulation has deteriorated to the extent that the transformers are at an increasing risk of failure. The paper insulation condition indicate the transformers have reached end of life and need to be replaced to maintain customer supply reliability. Insulation condition assessment testing completed in 2011 and 2014 indicated high ageing and high moisture content. In addition, the existing 1-2 66 kV bus-tie CB at HB is no longer supported by the manufacturer and consequently spare components such as 66 kV bushings, turbulators, solenoids and mechanism components are no longer available. The lack of spare parts translates to not being able to repair defects and recover from major faults.

HB zone substation is an island supplying 11 kV feeders with no load transfer capability to other zone substations due to being surrounded by 6.6 kV and 22 kV zone substations.

RIT-D status

On 13 February 2019, Jemena published Stage 1 of the HB transformer condition RIT-D, the Non-Network Options Screening Report (NNOSR). This report assessed possible non-network options for economically mitigating the identified risks at HB. The NNOSR conclusion is that none of the potential non-network options investigated represent technically or commercially feasible alternatives, nor could any combination of non-network options adequately address the identified need. Jemena did not receive any submissions on this NNOSR, therefore the following section constitutes the (Final Project Assessment Report) FPAR for this RIT-D project. It should be noted as the preferred network option is less than $10 million, therefore Jemena is not required to publish a draft project assessment report per clause 5.17.4(n) of the NER.

Network options consider

The following network options were assessed to manage the risk associated with the deteriorating condition of the HB transformers:

- Option 1: Do nothing, run to fail;
- Option 2: Replace the two existing 66/11 kV transformers;
- Option 3: Increased maintenance and monitoring;

- Option 4: Transformer refurbishment;
- Option 5: Transformer rewind; and
- Option 6: Transfer load

Project outcome

Jemena has identified that Option 2 to replace the existing two transformers at HB Zone Substation with modern equivalents will address the project identified needs and is the option that maximises the net market benefits to consumers.

Based on this analysis, Option 2 is about to be a committed project which is due for completion in 2022.

The estimated construction timetable is as follows:

- Business case approval: Febuary 2020 (in progress);
- Primary design complete: June 2020;
- Secondary design complete: September 2020;
- Construction start: November 2020; and
- Commissioning complete: October 2022.

5.7.4 FOOTSCRAY WEST ZONE SUBSTATION (FW) SWITCHGEAR AND RELAY CONDITION

Identified need

Footscray West Zone Substation (FW) comprises three 66/22 kV 20/30 MVA transformers and three 22 kV buses supplying eight 22 kV feeder lines. FW supplies areas of Footscray West, Yarraville, Spotswood and Brooklyn.

The condition of the 22kV switchgear and protection relays at Footscray zone substation (FW) is poor. There is an unacceptable risk of failure with significant consequences for staff safety, and the reliability of electricity supply to Jemena customers. The need to remove the asset from service has been demonstrated.

The most urgent concern for Jemena is the evidence of escalating partial discharges from the switchgear, and the threat this poses to staff safety and customer reliability.

RIT-D status

On 21 September 2018, Jemena published Stage 1 of the FW switchgear and relay condition RIT-D, the Non-Network Options Screening Report (NNOSR). This report assessed possible non-network options for economically mitigating the identified risks at FW. The NNOSR conclusion is that none of the potential non-network options investigated represent technically or commercially feasible alternatives, nor could any combination of non-network options adequately address the identified need. Jemena plans to publish Stage 2, the Draft Project Assessment Report (DPAR) for this project in December 2019.

5.8 METERING AND INFORMATION TECHNOLOGY SYSTEMS

5.8.1 METERING AND INFORMATION TECHNOLOGY INVESTMENTS IN 2018

The forecast metering and Information Technology (IT) capital expenditure plan for 2019 provides $21.5 million of budget for IT projects, which is consistent with completion of the 2016-2020 EDPR asset management plan submission, determination and capital expenditure allowances, including:

- Continuing work on the replacement to the SCADA OMS/DMS scheduled for completion in 2020;
- Major system upgrades for the Advanced Metering Infrastructure (AMI) meter data collection product suite;
- A major system upgrade for the AMI data warehouse used for reporting;
- Improvements to work order management through digitisation of paper based processes;
- Improvements to the design, estimate, build, closeout process for new construction and system maintenance to ensure correct “as-built” data is reflected in the Geospatial Information System (GIS) and SAP ERP;
- Commencement of work on the implementation of 5-minute meter reading and global settlement compliance requirement which will continue through to 2021;
- 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 availability of systems:
  - Application upgrades (version updates, patching, activating additional functionality);
  - Platforms and processing (servers, data storage and backup, Operating Systems, database mgt. systems);
  - End user services (PCs, productivity tools, field mobility equipment); and
  - Organic growth as the market and business grows

The 2016-20 regulatory outcome has approved $136.7 million (nominal $’s) for IT capital expenditure over the 5 year period. The actual and forecast annual IT capital expenditure for the 2016-2020 is shown in Table 5–13. Actuals are drawn from the RIN reporting and forecasts are drawn from the EDPR submission which has projected the Program of Work for IT out to 2025.

Table 5–13: IT Capital Expenditure Actuals and Forecasts 2016-2025

	Actual / Forecast Expenditure ($ millions)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
IT Capital Expenditure	14.2	30.9	21.3	21.5	22.5	33.6	19.8	26.1	14.4	7.5

Notes:

- Actuals for 2016-2018 are in nominal dollars.

- Data for 2016-2018 include IT project costs, accruals and other financial adjustments for those years and are aligned with the RIN data provided to the AER.
- Forecasts for 2019-2025 are in $2019 mid-year.
- All years are calendar years for this view of the forecast. It is recognised that the AER will in future years (post 2021) be basing the JEN regulatory year on financial-year boundaries.
- Compliance related projects are included in the figures. Notably the rule changes for Power of Choice ($21.3 million in 2016-18) and 5-minute metering and global settlement ($21.2 million in 2018-2021).
- SCADA OMS/DMS projects are included in the data as these are classified as non-network IT by the AER. A major replacement project is currently ongoing and is expected to be completed in the current period. Future periods will see lifecycle upgrades and maintenance of this replacement system.
- Future Network initiatives ($20.1 million in 2020-2025) are included in the forecast with most of the delivery occurring in the coming regulatory period. These projects prepare for the adoption and proliferation of Distributed Energy Resources across the distribution network.
- Forecasts for 2021 onwards are subject to review and approval by the AER and may alter as a result of their determintation.

5.8.2 METERING AND INFORMATION TECHNOLOGY INVESTMENT PLAN 2020 TO 2025

The metering and information technology (IT) program of work for the 2020-2025 can be summarised to represent the following five themes:

- Delivering new capabilities to the business that are aligned to market trends and changing industry focus;
- Improving existing capabilities to minimise risk and drive efficiencies;
- Enabling business transformation as a key to delivering Jemena's business plan;
- Responding to business needs in terms of implementing capabilities and enabling solutions that drive regulatory and other priorities; and
- Defending against cyber-threats.

The major projects planned for the 2020-2025, listed in Table 5–14 represent a mix of replacement projects and the introduction of new capability for Jemena. The purpose of establishing new system capabilities in JEN is to deliver services and efficiencies in accordance with current benchmarks set by Australian distribution energy businesses and to align Jemena with good industry practice in IT management.

Table 5–14: Metering and IT investment summary 2020-2025

Project	Investment Description
Customer Relationship Management	New capability in the current period followed by extending and integrating the current customer management services into a single customer experience hub in the coming period.
Outage Management and Distribution Management	The replacement this period of the Outage Management System as it reached end of life. The addition of Distribution Management capability to the system. Adding capability for outage and phase identification from smart devices on the network.

Project	Investment Description
	In the forthcoming period, this newly implemented system will require lifecycle upgrades and support.
Business Analytics	Replacing end of life business intelligence technologies in this period and extending capability and leverage the AMI data to improve the energy distribution services through analytics and decision support information. These services will be maintained and built upon in the forthcoming EDPR period.
Data Warehouse Replacement Project	Replace and extend the current AMI Data Warehouse to all of JEN's data in this period to underpin the business analytics. In the coming period, these systems will be maintained to continue their support of the analytics.
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 information through integration with systems sources for asset and image data.
Corporate and Field Mobility	New capability that provides devices, network communications and integration to IT systems to support provision of services to customers.
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 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 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 licenses and capacity growth.

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 Jemena and our customers.

The Victorian Government mandated a full roll out of AMI to small business and residential customers in 2006. By 2014, Jemena had successfully completed the deployment of smart meters to 98% of our residential and business customers with a consumption under 160 megawatt-hour per year.

While the primary aim of the AMI project was to enable customers to make choices about how much energy they use by allowing them to access accurate real-time information about their electricity consumption, many features of AMI are not yet fully realised that have the potential to provide additional customer benefits, such as:

- Real-time reports of supply outage and restoration, enabling faster fault detection and restoration;
- Customer supply quality monitoring, enabling pro-active 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;
- Emergency load limiting to maintain network integrity when discretionary load limiting fails; and
- Customer enabled load limiting.

In 2016, Jemena initiated plans to leverage the AMI to further develop a smart network and improve its service delivery to customers, including:

- Using AMI data (and SCADA data) to analyse the network and develop intelligence and insight for more efficient and effective network management and operation; and
- Deliver network benefits by using AMI, integrated with Jemena's network outage management system to deliver improved operational efficiency, enhanced asset safety, improved supply reliability and quality, and better customer service.

As outlined in Section 3.5.5, Jemena is currently undertaking a "supply monitoring" project. The upgrade to the AMI system to collect 5 minute synchronised data (voltage, current and power factor) was deployed at the end of October 2017 and performance testing for a small subset of meters started in November 2017. Data collection was extended to all AMI meters in June 2018 enabling regulation, supply impedance and connection phase to be assessed across the network.

Analytics functions are being built on an "R" platform independent of the existing and new enterprise data bases and analytic services. It is expected that some form of integration may occur in 2018/19 to further enhance Jemena's customer and network analysis capability.

5.9 DEMAND MANAGEMENT

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 technology innovations and consumer preferences, and, in line with these changes, Jemena'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 Australian Energy Regulator (AER)[15] 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 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 or in response to price signals, or by the DNSP through direct load control;
- Embedded generation;
- Energy storage and subsequent release at peak times, including electric vehicles fitted with vehicle-to-grid technology; 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. Distribution Businesses and their customers carry operational risks that can be quantified as the cost of expected unserved energy (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 and the DM technologies and business processes employed, which must react fast enough to mitigate the impacts of network outages.

5.9.1 DEMAND MANAGEMENT OBJECTIVES AND STRATEGY

Jemena'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

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15 AER, Final Framework and Approach for the Victorian Electricity Distributors, October 2014, p113

- Where economical, resolve network supply quality and capacity constraints using DM.

Jemena’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 in order to achieve “Investment Flexibility”, help non-network services grow for the future and to ensure uptake of a DM solution in the current market conditions;
  - Implementing DM where economically beneficial to customers and value maximising for Jemena; and
  - Collaborating with specialist providers and developing Jemena’s intellectual property.
- Lead the Australian electric utility sector in the successful 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; and
  - Supporting the development of demand management and alternative technology solutions as part of Jemena’s growth strategy for its regulated and unregulated businesses.
- Extend Jemena’s demand management capabilities in line with the long term corporate strategy for the business.

5.9.2 DEMAND MANAGEMENT INITIATIVES

Jemena’s proposal for an expanded demand management innovation program under the AER’s 'Demand Management and Embedded Generation Connection Incentive Scheme’ (DMEGCIS), for the 2016-2020 regulatory control period, was not accepted by the AER. In view of the significant reduction in the incentive allowance from its proposal, JEN has reviewed its demand management program and intends to focus on the following areas in 2020-2024:

- Efficient connection of micro-embedded generators;
- Manage peak demand through demand response from customers; and
- Explore the use of renewable embedded generation (PV) and energy storage for network peak demand support.

In 2017/18 and 2018/19 summer periods Jemena undertook a number of demand management initiatives:

Residential demand response (Power Changers) - a behavioural demand response for residential customers. The trial was jointly supported by Jemena and Vic. Gov. (DELWP). This provided significant learnings which were shared widely through stakeholder workshops and a public report. Also energy literacy events with Uniting Care for *Power Changers Community Connections* program were undertaken.

A proof of concept for direct load control (DLC) of residential air-conditioners was also part of the Power Changers program. In addition, a very limited trial of using commercially available infra red (IR) blaster technology to remotely control air-conditioners was also undertaken providing first hand knowledge of the technology.

Commercial and industrial (C&I) demand response – A 2 MW trial in Flemington zone substation area using a 3rd party agreegator was undertaken. At the request from AEMO (for load shed) on Friday 25th January 2019, Jemena deployed its demand response program. This event, running from just under three hours, helped to keep hundreds of local residents connected to the grid.

Voltage reduction demand response – A trial at four zone substation was conducted to acquire operational experience. Risk to customer's quality of supply was mananged by using 5 minutes data from smart meters. In addition, this technique was put in place to manange operational risks at Coburg South (CS) zone substation. This data has been analysed to estimate voltage-power relationship on a hot day in Jemena's electricity network.

The following demand management initiatives were commenced in 2019 and will continue into 2020:

Residential behavioural demand response 2.0 – A new DR program has been designed which will be put in place during 2019/20 summer. This program has the following elements:

Behavioural demand response: A number of areas have been identified with emerging network limitations such as Essendon, Somerton, Coolaroo, Coburg South, Yarraville, Footscray East and Airport West. The main aim of the new DR program is to achieve cost effective DR which can provide an alternate to network options. This program will be implemented in partnership with an energy retailer.

Voltage reduction DR – this will be implemented at Coolaroo and Coburg South zone substations to manange the risks from network limitations.

An update on the initiatives listed avobe will be provided in the next report.

Jemena continues the up-keep 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

Jemena has not identified any network projects in the forward planning period which can be deferred through demand management.

5.9.4 CUSTOMER PROPOSALS

In 2019, Jemena has received three connection enquiries for embedded generators that have a generation capacity greater than 5 MW. Jemena believes this low level of enquires for larger embedded generator is due to a reflection of:

- 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 roof top solar, for which the JEN network has seen an ongoing increase in installed capacity.

Notwithstanding this, Jemena will continue to investigate opportunities for embedded generation projects that can reduce network investment while maximising customer benefits.

Table 5–15 provides a quantitative summary of the connection enquiries and applications to connect EG systems received in 2019 under chapter 5 of the NER.

Table 5–15: Summary of embedded generation connections in 2019

Description	Quantity (>5 MW)
Connection enquiries under NER clause 5.3A.5	3
Applications to connect received under NER clause 5.3A.9	0
Average time taken to complete Applications to Connect	N/A

5.10 FACTORS THAT MAY MATERIALLY IMPACT THE NETWORK

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

Rapid Earth Fault Current Limiter (REFCL)

To limit the impact of earth fault currents acting as an ignition source in high risk bushfire areas, Jemena installed a REFCL at Sydenham (SHM) Zone Substation in 2017[16]. There are plans to install and commission a REFCL at Coolaroo (COO) Zone Substation by 30 April 2023. The REFCL at COO is required to meet the prescribed performance requirements in the Electricity Safety (Bushfire Mitigation) Regulations 2013. Installation of a REFCL at Sunbury (SBY) Zone Substation has been deferred beyond the forward planning period.

Under Victoria's Electricity Safety (Bushfire Mitigation) Regulations 2013[17] (including subsequent amendments made in 2016 and 2017) (**ES Regulations**), JEN is responsible for ensuring that all feeders originating from COO meet the Required Capacity by 1 May 2023. Additionally, JEN takes supply for three of its feeders in the nearby area from the Kalkallo zone substation (KLO), which is owned by AusNet Services and must also meet the Required Capacity by 1 May 2023. As well as overhead lines in high bushfire risk areas, the supply areas of both COO and KLO include a number of residential estates in Melbourne's northern growth corridor where the distribution network is underground, preventing the simple installation of REFCL equipment at either zone substation.

Recognising the interrelationships between COO and KLO, JEN and AusNet Services engaged consultant WSP to assist in a joint planning exercise to examine a number of 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. This exercise identified 24 options. Through this process, we identified that there was only one option which did not require any exemptions from the requirements of the Electricity Safety (Bushfire Mitigation) Regulations.

This option is significantly more costly than other options identified (which require partial exemptions from the Electricity Safety (Bushfire Mitigation) Regulations for underground sections of line which do not pose a bushfire ignition risk) yet does not provide any additional benefit to consumers or the broader community in terms of bushfire risk reduction. However, as neither JEN nor AusNet Services have obtained any exemptions to date from the Electricity Safety (Bushfire Mitigation) Regulations for COO or KLO, our forecast capital expenditure reflects

16 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.

17 Authorised Version incorporating amendments as at 1 May 2016. http://www.legislation.vic.gov.au/domino/Web_Notes/LDMS/LTObject_Store/ltobjst9.nsf/DDE300B846EED9C7CA257616000A3571/633C43B024A8E558CA257FA3007AD2ED/$FILE/13-62sra004%20authorised.pdf

the most prudent and efficient cost of complying with this regulatory obligation[18,19] without assuming we will successfully obtain an exemption in the future.

Our proposed scope of the works to comply with the Electricity Safety (Bushfire Mitigation) Regulations would result in REFCL protection of all overhead and underground lines originating from COO (and KLO) by 1 May 2023, through:

- Installing two REFCL devices at COO, plus associated network balancing[20] network and hardening[21] works on feeders supplied by COO;
- Constructing a new zone substation in the Greenvale area (referred to as GVE) and transferring some existing COO feeders to GVE. This is required as the REFCL equipment at COO would not be sufficient to meet the capacitance of all feeders in the area, noting that it is not possible to install more than two REFCLs at this zone substation. GVE would have two transformers and two REFCLs;
- Undertaking network hardening works on four JEN feeders which will be supplied by a new Kalkallo North zone substation[22] (to be constructed by AusNet Services) which will be REFCL protected; and
- Purchasing specialist test equipment and a heavy commercial vehicle (test truck) and installing testing points on the poles required for JEN to carry out the mandatory annual pre-summer earth fault testing activities[23], for COO including primary earth fault testing.

We recognise that expenditure to fully comply with the Electricity Safety (Bushfire Mitigation) Regulations represents a significant potential cost for our customers to bear. We are therefore committed to pursuing an exemption from the Electricity Safety (Bushfire Mitigation) Regulations for underground feeders originating from COO which would allow us to instead implement a lower cost option while still effectively mitigating bushfire risk in the relevant areas.

Note that this project is not yet committed and is therefore subject to the RIT-D process; however, a non-network solution is unlikely to be considered sufficient to mitigate the bushfire risk.

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 EDC. Where the regulatory requirements differ, Jemena plans its network to the most onerous standard. The estimated maximum prospective short-circuit level are included in the subsections of Section 5.11 for each of the Jemena owned zone substations.

Table 5–16 shows the maximum allowable short-circuit fault levels (by voltage), as specified in the EDC.

18 The Electricity Safety (Bushfire Mitigation) Regulations fall within the meaning of a regulatory obligation or requirement as set out in the *National Electricity Law* s 2D(1)(b)(v).

19 Consistent with *National Electricity Rules* s 6.5.7(a)(2).

20 Capacitance balancing to ensure the REFCL can operate correctly.

21 Replacing equipment with insufficient insulation ratings to ensure this equipment does not fail when the REFCL operates, as the operation raises the phase to ground voltage on non-faulted phases.

22 These JEN feeders are currently supplied by KLO.

23 These testing activities are required under *Electricity Safety (Bushfire Mitigation) Regulations 2013* s 7(1)(hb).,

Table 5–16: 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 result 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, Jemena 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 installation of 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 EDC limits.

Under the Electricity Safety (Bushfire Mitigation) Regulations 2013, all feeders originating from COO and KLO must meet the Required Capacity by 1 May 2023. This includes limiting fault current on the COO and KLO feeders to 0.5 amps or less in the event of a phase-to-ground fault on a polyphase electric line with a nominal voltage between 1kV and 22kV.

There are no single replacement projects in excess of $2.0 million within the forward planning work program that are driven by fault level issues.

Voltage levels

All customer equipment requires the supply voltage to remain within allowable bounds in order to function correctly. Jemena is required to maintain customer voltages within specified thresholds, which were presented in Table 3–6 JEN network voltages are affected by:

- The amount of generation supplying the JEN network – In recent years Jemena has been investigating voltage control challenges posed by 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. With completion of the smart meter rollout program, Jemena now has the capability to 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 Jemena is developing proactive measures to address voltage rise issues that are impacting on Jemena’s customer voltage supply.

- Impedance of transmission and distribution network equipment – higher impedance equipment, such as long sub-transmission 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.
- 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. Jemena installs capacitors at its zone substations to supply reactive power demand, and support network voltages.
- REFCL condition - Rapid Earth Fault Current Limiter (REFCL) is an enhanced earth fault detection and suppression device, 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. By doing so, however, it raises the voltage on the healthy phases by 73% (nominally from 12.7kV to 22kV). The implication of higher voltages on healthy phases means that deployment of REFCL may require significant asset replacement and network hardening to ensure that all assets are rated for the higher voltages that they would be exposed under earth fault conditions. Hence, customers directly connected to high voltage of REFCL protected networks may need to take action in response to REFCL deployment in Jemena Electricity Networks. The REFCL deployment at a zone substation generally impacts the assets connected to its high voltage (22kV) 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 5–17: Feeders which may experience a REFCL condition

Year	Current	2023
REFCL Zone Substation	SHM[24]	SHM, COO and KLO
Non-REFCL protected feeders which may experience a REFCL condition	SBY-32, SA-6, SA-10, SA-12, MLN-21	SBY-32, SA-6, SA-10, SA-12, MLN-21, AW-9, BD-9, BD-14, SBY-24, ST-12, ST-32, ST-33, ST-22

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

- Operate the on load tap changer (OLTC) of zone substation or the transmission connection point transformers to lift the customer side voltage, noting that Jemena 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, 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, Jemena will undertake one of the following corrective actions on an as needs basis:

- Operate distribution transformer off-load tap changer;
- Upgrade distribution substations;
- Balance load across LV circuits; or

[24] 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.

- Re-conductor LV circuits.

There is no single replacement project in excess of $2.0 million in the forward planning period that is driven by voltage level issues.

Power system security

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.

Jemena sets its asset limits to ensure power system security, and this is prioritised above power supply. Load transfer or shedding would be implemented, even under system normal conditions, if required to ensure secure operation of the network is achieved at all times. Any expected unserved energy required to ensure power system security would be included in the network risk identification and options analysis.

Quality of supply

Jemena is required to comply with the requirements in Section 4 of the EDC 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.

Jemena 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 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 on an as needs basis.

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

Power system reliability

Power system reliability refers to the capacity of the power system to deliver all customer load. Given that Jemena 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.

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

In the forward planning period, the following network augmentations in excess of $2.0 million include provision for the replacement of aged based on condition based assessment and unreliable assets:

- Conversion of the Preston and East Preston area from 6.6 kV to 22 kV. The conversion program of P and EP commenced in 2008 and is planned to be completed in stages by around 2024 (see Section 5.11.8). The conversion program upgrades the supply capacity to the area while addressing the 6.6 kV asset condition and reliability issues;
- Footscray East and Footscray West zone substation works, (see sections 5.11.13 and 5.11.14) include the replacement of obsolete and unreliable 22 kV switchgear;
- Heidelberg Zone Substation works (see section 5.11.10) include replacement of 66/11 kV transformers;
- Broadmeadows Zone Substation works (see section 5.11.3) replacement of 66/22 kV transformer; and
- Coburg North Zone Substation works (see section 5.11.5) replacement of outdoor 22 kV circuit breakers and associated protection relays.

5.11 ZONE SUBSTATION AND HV FEEDER LIMITATIONS

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 (2020-2024) and the annualised cost of expected unserved energy for identified zone substation limitations.

The section also includes recently completed projects and network developments that Jemena is committed to deliver within the forward planning period.

Zone substation limitations

Each of the identified zone substation limitations and network impacts incorporate 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 to the system normal (N secure) rating and N-1 rating. The maximum demand forecasts and zone substation ratings presented in these figures are for each zone substation's peak loading period (summer or winter);
- The 10% POE MD (presented in MVA), during each zone substation's peak demand period for existing and committed zone substations;
- Power factor at peak load (p.u), being the power factor at the time of peak 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 (%), being the maximum zone substation loading that is forecast to occur during the peak demand period following the worst credible contingency. This loading level is presented as a percentage of the substation's N-1 rating for the peak demand period;
- Maximum load at risk (MVA), being the load that would be lost if the worst credible outage occurred at the time of peak demand;
- Hours at risk (h), being the number of hours where the zone substation loading is forecast to exceed the N-1 rating in a given year and is therefore at risk of not being supplied if the worst credible outage occurs;
- The EUSE (MWh), being the expected unserved energy associated with a network outage in a given year and the probability of that network outage actually 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), being the cost of expected unserved energy in a given year (see Section 2.4.2.4 for more information);
- Embedded generation, being the known amount of large (units above 2 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, Jemena 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 6.20% and an asset life of 50 years.

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 give an indication of the additional support that can potentially be provided under emergency conditions.

Feeder limitations

Each zone substation limitation assessment outlines the identified feeder limitations, with utilisation levels based on 10% POE conditions, and the preferred solutions proposed. Assessing feeder limitations typically include consideration of the following risk mitigation options:

- Installing new feeders to offload existing heavily loaded feeders;
- Reconfiguring feeders to balance loading between existing feeders and to ensure sufficient transfer capability in the case of a network outage;
- Thermally uprating existing feeders (or existing feeder sections) to enable them to safely carry more load;
- Replacing the conductor (or conductor sections) of an existing feeder with higher capacity conductor to enable it to safely carry more load;
- Installing embedded generation suitably located in the feeder supply area to offload the existing feeder; and
- Introducing demand management schemes suitably located in the feeder supply area to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads, as negotiated with customers, by offering customer incentives in the form of reduced electricity prices or outage rebates.

Feeder ratings

In the preceding 12 months, Jemena has also undertaken a review of its HV distribution feeder ratings. A detailed analysis, using cable modelling software tool (CYMCAP), was conducted to review the correct thermal rating based on feeder exit cable size, construction and actual layout (i.e. depth and clearance to adjacent cables) from as-built construction drawings. This analysis resulted in the revision of 40 distribution feeders thermal rating.

5.11.1 AIRPORT WEST ZONE SUBSTATION (AW)

Background

The Airport West Zone Substation (AW) comprises three 66/22 kV 20/30 MVA transformers, one 66/22 kV 20/40 MVA transformer, and three 22 kV buses supplying twelve 22 kV feeder lines. AW supplies the areas of Airport West, Tullamarine, Keilor East and Avondale Heights. Airport West is a critical zone substation that supplies ten of Jemena's high-voltage customers.

Substation limits

Consistent with the ratings listed in Table 5–18, AW's summer and winter capacities are limited by the 66/22 kV transformer thermal limits.

Table 5–18: Airport West Zone Substation ratings

	Summer	Winter
Substation N rating	130.0 MVA	130.0 MVA
Substation N-1 rating	100.5 MVA	120.7 MVA

Substation fault levels

Table 5–19 presents AW's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–19: Airport West Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	13.7 kA	9.6 kA
LV 22 kV	12.4 kA	2.5 kA

Network impact

There is adequate capacity under N-1 conditions to meet the forecast maximum demand under 10% POE and 50% POE conditions for the forward planning period.

Figure 5-3 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-3: Airport West Zone Substation maximum demand forecast loading

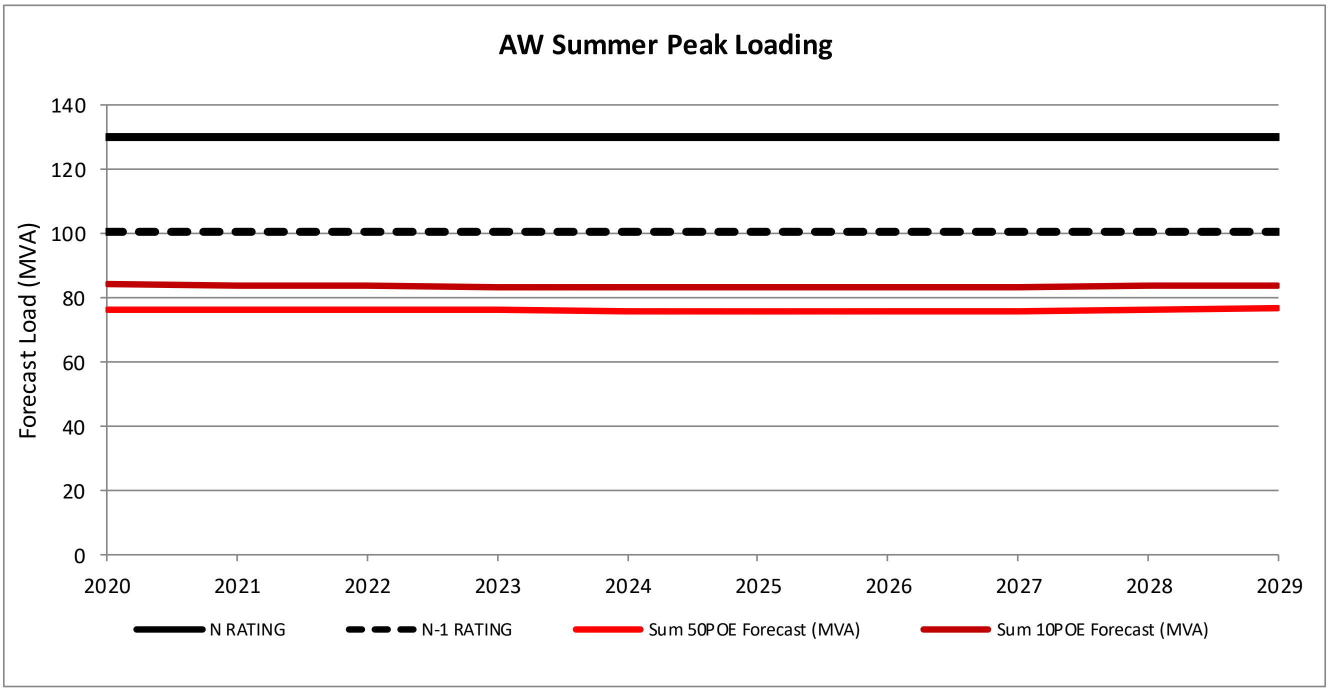

Table 5–20 shows the system normal maximum demand forecast, 95% of which is expected to be reached two hours per year, and the power factor at the time of peak load. It also shows the forecast N-1 loading, and that there is no load at risk forecast at AW.

Table 5–20: Airport West Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	84.3	83.6	83.8	83.0	83.1
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
10% POE N-1 loading (%)	84%	83%	83%	83%	83%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

This substation does not have any large embedded generation connected to it but has up to 35.1 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

There is no forecast load at risk.

Proposed preferred solution

No further solutions are required.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the twelve AW feeders is forecast to reach 66.7% in 2020, increasing to 67.1% by 2024.

With utilisation rates on feeders AW-01, AW-06 and AW-07 forecast to reach 105.0%, 128.1%, and 121.8% (respectively) by 2024, Jemena is proposing to undertake a network augmentation projects to manage AW feeder loadings during the forward planning period:

- Reconfigure the AW-01, AW-05, AW-06, AW-07 and AW-08 feeders to balance load across them by November 2020, at an estimated cost of $463 thousand. This project involves:
  - Installation of 3 remote controlled gas switches.
  - Reconductor approximately 800m overhead HV made from 65SR to 19/3.25 AAC.
  - Reconfiguring the AW-01, AW-05, AW-06, AW-07, AW-08 and TMA-11 feeders to balance their loads.

Following reconfiguration, load will be balanced between these feeders and there will be sufficient transfer capacity under single contingency conditions for feeder AW-01, AW-06, AW-07 and all adjoining feeders. Without implementation of this option, up to 5.9 MVA of load reduction under system normal conditions and 10.2 MVA of load reduction under outage conditions would be required at AW-06 and AW-07 feeders.

An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $30 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.2 BRAYBROOK ZONE SUBSTATION (BY)

Background

Braybrook Zone Substation (BY) comprises one 66/22 kV 20/30 MVA transformer, one 66/22 kV 20/33 MVA transformer and two 22 kV buses supplying five 22 kV feeder lines. BY supplies the areas of Braybrook, Maidstone, Maribyrnong and Footscray.

Substation limits

Consistent with the ratings listed in Table 5–21, BY's summer and winter capacities are the 66/22 kV transformer thermal limits.

Table 5–21: Braybrook Zone Substation ratings

	Summer	Winter
Substation N rating	45.0 MVA	45.0 MVA
Substation N-1 rating	32.0 MVA	39.6 MVA

Substation fault levels

Table 5–22 presents BY's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–22: Braybrook Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	10.5 kA	6.6 kA
LV 22 kV	8.6 kA	1.6 kA

Network impact

The load supplied by the substation under 10% POE and 50% POE summer maximum demand conditions already exceeds the substation's N-1 capacity. Based on the 10% POE summer maximum demand, outage of a 66/22 kV transformer will result in involuntary load shedding of up to 10.0 MVA in 2020.

With both transformers in service, there is adequate capacity to meet the anticipated maximum demand for the forward planning period.

Figure 5-4 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-4: Braybrook Zone Substation maximum demand loading

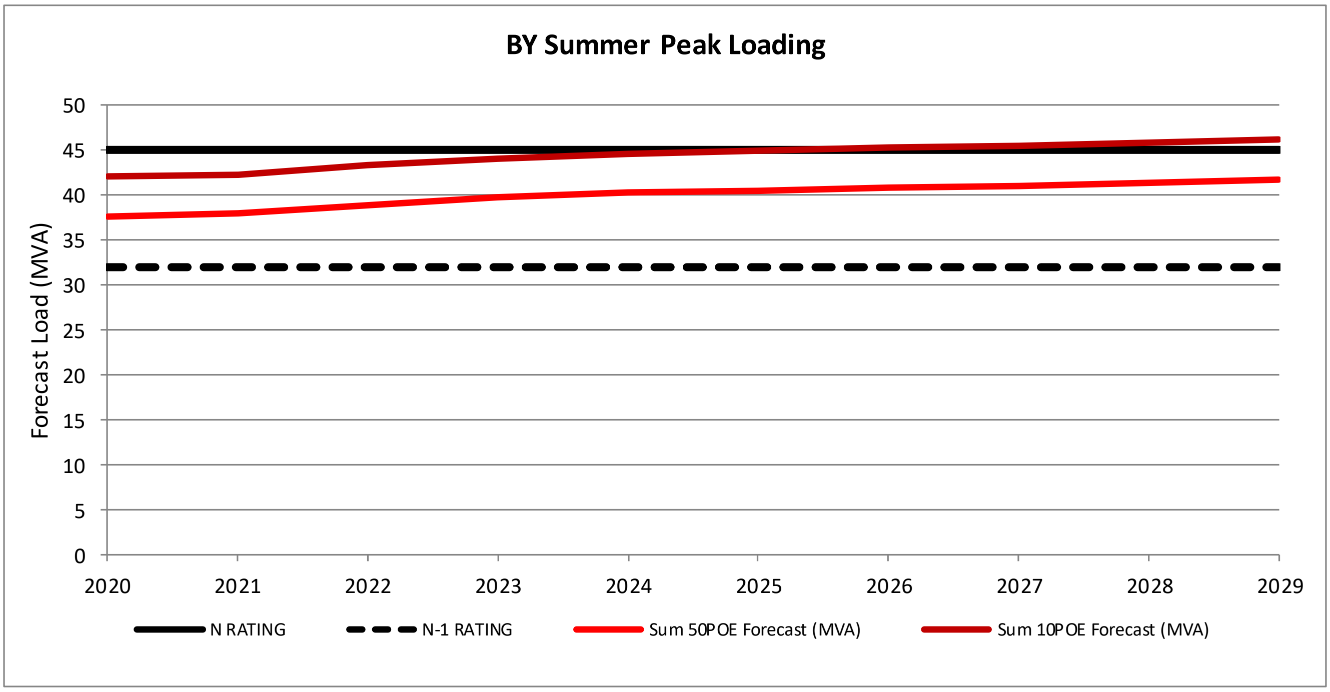

Table 5–23 shows the system normal maximum demand forecast, 95% of which is expected to be reached seven hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–23: Braybrook Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	42.0	42.2	43.3	44.0	44.7
Power factor at peak load (p.u)	0.94	0.94	0.94	0.94	0.94
10% POE N-1 loading (%)	131%	132%	135%	137%	140%
Max load at risk (MVA)	10.0	10.2	11.3	12.0	12.7
Hours at risk (h)	50	53	64	77	85
EUSE (MWh)	0.5	0.6	0.8	1.0	1.2
Cost of EUSE ($ thousand)	22.3	24.0	32.8	41.1	47.6

The table shows that a load reduction of 10 MVA in 2020 would defer any forecast limitation by 12 months, even under N-1 conditions.

This substation has no large embedded generation connected to it but has up to 24.8 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

Five options have been considered for managing the identified network limitations:

- Option 1: Piggyback off the establish feeder TMA-015 project to provide additional load transfer capacity away from BY;
- Option 2: Establish feeder Tie's between BY and FW feeders to permanently transfer load away from BY to FW zone substation;
- Option 3: Establish a new zone substation in Avondale Heights. This option will provide sufficient capacity to meet anticipated load growth in the Braybrook area to alleviate existing and emerging constraints;
- Option 4: Establish embedded generation suitably located in the BY supply area; and
- Option 5: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves the introduction of interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

Jemena has identified that Option 1 maximises the net economic benefits over the life of the assets. The establishment of new feeder TMA-015 will primary address the capacity constraints on AW feeders, however, this project will also provide additional transfer capacity away from BY to AW feeders. This additional transfer capacity together with the existing transfer capability under emergency condition will reduce and manage the impact of supply outage under N-1 conditons at BY. The project is currently proposed to be completed by November 2024 at an estimated cost of $2,330 thousand.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the five existing 22 kV BY feeders is forecast to reach 50.2% in 2020, and increasing to just 57.1% by 2024. Feeder BY-13 is the heaviest loaded with utilisation forecast to reach 91.2% by 2024.

With modest utilisation and a relatively flat demand forecast, Jemena is not planning any feeder augmentation at BY for the forward planning period..

5.11.3 BROADMEADOWS ZONE SUBSTATION (BD)

Background

Broadmeadows Zone Substation (BD) comprises three 66/22 kV 20/30 MVA transformers, one 66/22 kV 20/33 MVA transformer and three 22 kV buses supplying fourteen 22 kV feeder lines. BD supplies areas of Broadmeadows, Meadow Heights, Jacana and Campbellfield.

Substation limits

Consistent with the ratings listed in Table 5–24 BD's summer and winter capacities are limited by the 66/22 kV transformer thermal limits.

Table 5–24: Broadmeadows Zone Substation ratings

	Summer	Winter
Substation N rating	123.0 MVA	123.0 MVA
Substation N-1 rating	123.7 MVA	125.1 MVA

Substation fault levels

Table 5–25 presents BD's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–25: Broadmeadows Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	13.7 kA	8.5 kA
LV 22 kV	12.2 kA	2.2 kA

Network impact

There is adequate capacity under N-1 conditions to meet the forecast maximum demand under 10% POE and 50% POE conditions for the forward planning period. Figure 5-6 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-5: Broadmeadows Zone Substation maximum demand loading

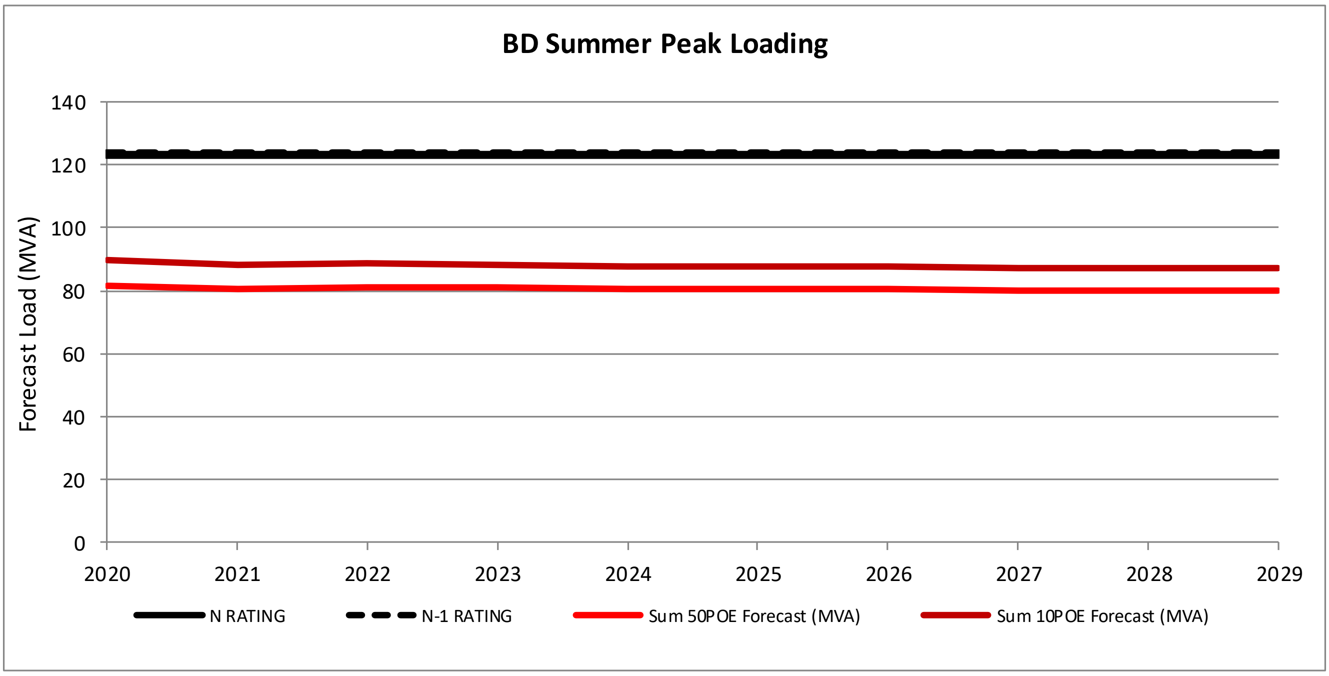

Table 5–26 shows the system normal maximum demand forecast, 95% of which is expected to be reached nineteen hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–26: Broadmeadows Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	89.7	88.3	88.8	88.0	88.0
Power factor at peak load (p.u)	0.97	0.97	0.97	0.97	0.97
10% POE N-1 loading (%)	73%	71%	72%	71%	71%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

This substation has no large embedded generation connected to it and up to 36.5 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

There is no forecast load at risk.

Proposed preferred solution

No solutions are required.

Zone substation replacements

The existing No 1 and No 2 BD transformers are at a high risk of failure due to their poor condition. The condition based risk management (CBRM) health indices and poor paper sample degree of polymerisation (DP) transformer tests indicated that the transformers are in their end of life stage. The transformers require replacement within the forward planning period to maintain acceptable levels of supply reliability. To manage the risk of damage to key assets within BD Zone Substation due to condition-related failure, it is proposed to replace the existing No.2 66/22kV transformer with standard 20/33 MVA unit and make the existing No.1 66/22kV transformer a hot standby.

Four options have been considered to manage the risk associated with the aging transformers at BD:

- Option 1: Replace both No 1 and No 2 66/22 kV 20/30 MVA transformers with modern equivalent 20/33 MVA units;
- Option 2: Replace only 1 transformer of the existing 66/22 kV 20/30 MVA transformers with a new 20/33 MVA transformers and keep the other 20/30 MVA transformer as a hot spare;
- Option 3: Refurbish transformers; and
- Option 4: Installation of battery banks to offset the load demand in the event of failure of one of the in-service transformers at zone substation BD.

Jemena has identified that Option 2 maximises net economic benefits of the project whilst achieving an appropriate level of environmental, safety and operational risk and is therefore the preferred option for addressing the issues of two aging transformers.

This project has an estimated cost of $4.1 million and is scheduled for completion by November 2022.

There are also relay replacement works planned at BD as described in section 5.4.8.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the fourteen BD feeders is forecast to reach 56.9% in 2020, increasing to 57.6% by 2024.

BD-03 is the heaviest loaded feeder and is forecast to reach 94.0% utilisation by 2024; however, load on this feeder can be managed via existing transfers. Feeders BD-08, BD-13 and ST-34, supplying commercial/industrial customers in Campbellfield, are also highly loaded and have insufficient transfer capacity under contingency conditions. Jemena is proposing to undertake one feeder augmentation project at BD within the forward planning period:

- Reconfigure feeder BD-15 by November 2024 at an estimated cost of $578 thousand. This project involves installation of approximately 210 metres of underground cable and transferring load from BD-13 to BD-15. Without implementation of this project, up to 1.6 MVA of load reduction will be required under single contingency conditions in summer 2024-25.

  An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $38 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.4 BROADMEADOWS SOUTH ZONE SUBSTATION (BMS)

Background

Broadmeadows South Zone Substation (BMS) comprises two 66/22 kV 20/33 MVA transformers and two 22 kV buses, supplying six 22 kV feeder lines. BMS supplies the areas of Broadmeadows and Gladstone Park and provides support to neighboring areas of Campbellfield and Coburg.

Substation limits

Consistent with the ratings listed in Table 5–27, BMS's summer and winter capacities are limited by the transformer circuit breaker rating.

Table 5–27: Broadmeadows South Zone Substation ratings

	Summer	Winter
Substation N rating	47.6 MVA	47.6 MVA
Substation N-1 rating	38.0 MVA	39.6 MVA

Substation fault levels

Table 5–28 presents BMS's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–28: Broadmeadows South Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	12.8 kA	7.9 kA
LV 22 kV	8.9 kA	1.7 kA

Network impact

As a relatively new establishment to offload Broadmeadows Zone Substation, load is not expected to be at risk at BMS under system normal or N-1 conditions within the forward planning period.

Figure 5-6 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-6: Broadmeadows South zone substation maximum demand loading

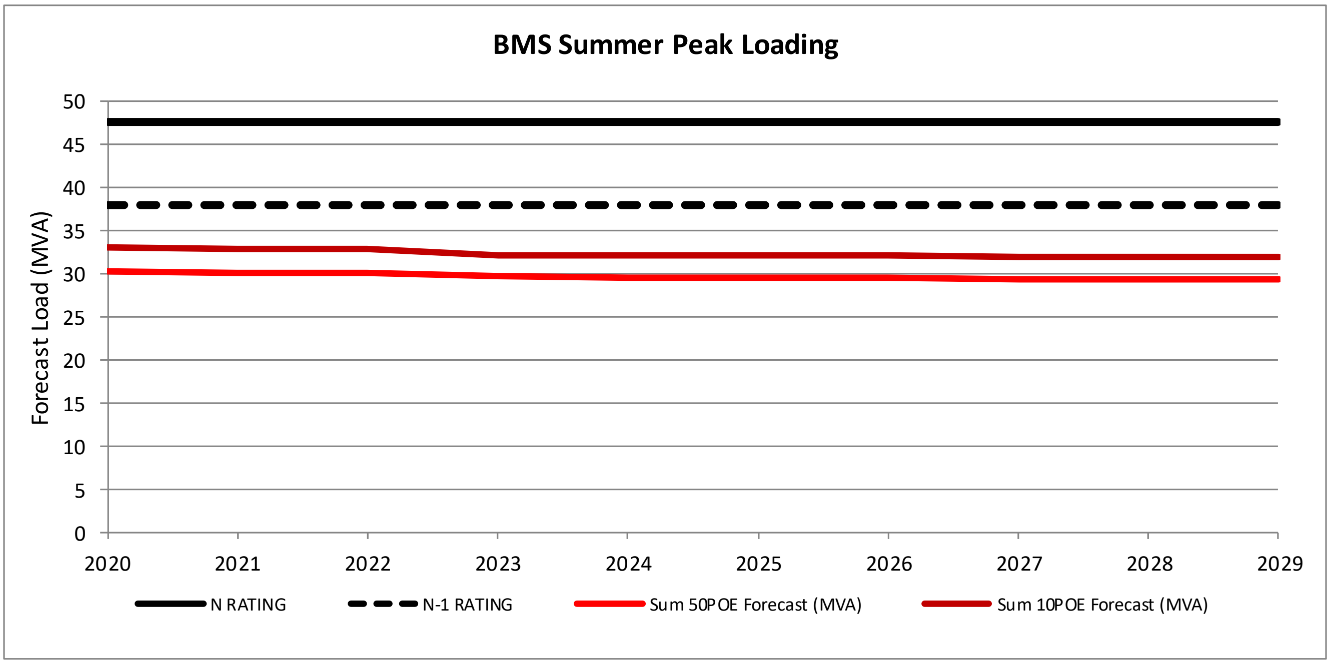

Table 5–29 shows the system normal maximum demand forecast, 95% of which is expected to be reached nineteen hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–29: Broadmeadows South Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	33.1	32.9	32.8	32.2	32.2
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	87%	86%	86%	85%	85%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

This substation has 6.4 MW of large embedded generation connected to it and up to 5.3 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

There is no forecast load at risk.

Proposed preferred solution

No solutions are required.

Zone substation replacements

No major replacement projects are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the six BMS feeders is forecast to reach 55.8% in 2020 and 57.1% by 2024. Feeder BMS-21 is the heaviest loaded with utilisation forecast to reach 78.9% by 2024. With modest utilisation and a relatively flat demand forecast, Jemena is not planning any feeder augmentations at BMS for the forward planning period.

5.11.5 COBURG NORTH ZONE SUBSTATION (CN)

Background

Coburg North Zone Substation (CN) comprises two 66/22 kV 20/30 MVA transformers, one 66/22 kV 20/33 MVA transformer, and three 22 kV buses supplying eleven 22 kV feeder lines. CN supplies areas of Coburg North, Fawkner, Reservoir and Preston.

Substation limits

Consistent with the ratings listed in Table 5–30, CN zone substation summer and winter capacities are limited by the 66/22 kV transformer thermal limits.

Table 5–30: Coburg North Zone Substation ratings

	Summer	Winter
Substation N rating	93.0 MVA	93.0 MVA
Substation N-1 rating	72.5 MVA	83.6 MVA

Substation fault levels

Table 5–31 presents CN zone substation estimated maximum prospective fault levels at the HV and LV buses.

Table 5–31: Coburg North Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	12.3 kA	7.6 kA
LV 22 kV	11.7 kA	2.5 kA

Network impact

There is adequate capacity under N-1 conditions to meet the forecast maximum demand under 10% POE and 50% POE conditions for the forward planning period.

Figure 5-7 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to substation limits (MVA).

Figure 5-7: Coburg North Zone Substation maximum demand loading

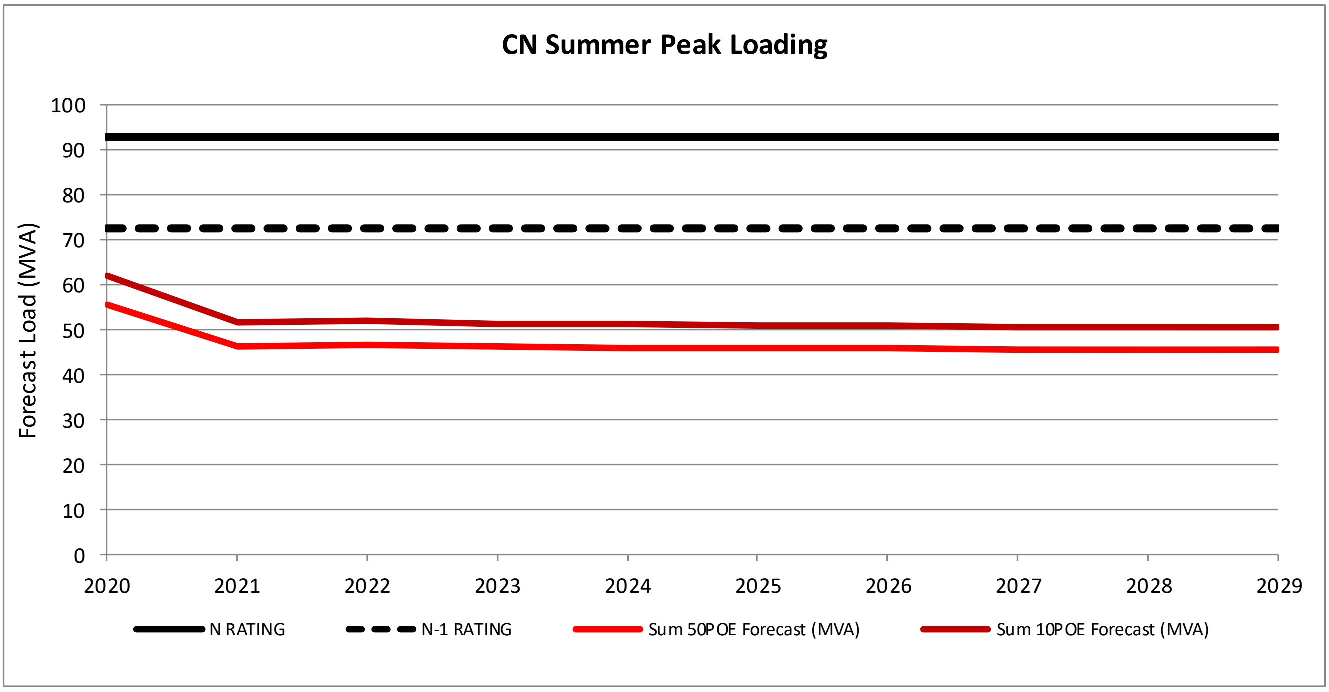

Table 5–32 shows the system normal maximum demand forecast, 95% of which is expected to be reached two hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–32: Coburg North Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	62.0	51.7	51.9	51.3	51.1
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
10% POE N-1 loading (%)	86%	71%	72%	71%	71%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

This station has 2.0 MW of large embedded generation connected to it and up to 12.6 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

There is no forecast load at risk.

Proposed preferred solution

No solutions are required.

Zone substation replacements

The 22kV, 66kV switchgear and capacitor bank at CN is at risk of failure due to its age and deteriorating condition. As the condition continues to deteriorate it poses serious safety and security of supply concerns. To manage the risks, this project involves replacement of three outdoor 22kV buses, two 66kV bus tie circuit breakers and zone substation capacitor banks. The existing outdoor 22kV CBs are also non-compliant with current switchgear standards for electrical arc fault containment standards. This presents a health and safety risk to Jemena personnel. In the event that the insulation fails, the resulting electrical arc and pressure wave will not be contained within the circuit breaker, and consequently the risk to employee health and safety is elevated. To address these prominent risks, the outdoor 22kV switchgear at CN is planned to be replaced with new indoor switchgear. A new building will be constructed to house all 22kV switchgear and protection and control schemes.

Three options have been considered to manage the risk associated with the aging 22 kV, 66 kV CB's and capacitor bank at CN:

- Option 1 – Do nothing, run to fail;
- Option 2 – Increased maintenance & monitoring for these types of CBs; and
- Option 3 – Replace 22 kV, 66 kV Circuit Breakers and capacitor banks.

Jemena has identified that Option 3 to replace the existing outdoor 22kV switchgear, 66 kV bus-tie CB's and capacitor banks at CN zone substation with new modern equivalents and installing them to current standards will address all the condition issues identified and maintain safety, reliability and security of customer supply.

This option is seen as the most technically viable and is the preferred network option. Jemena intends to complete this by November 2023 at an estimated cost of $6,775 thousand.

An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $442 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

There are also relay replacement works planned at CN as described in section 5.4.8.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the eleven CN feeder is forecast to reach 53.1% in 2020, and 45.2% by 2024. Feeder CN-07 and CN-08 are the heaviest loaded forecasted over the forward planning period. However, both CN-07 and CN-08 feeders will be reconfigured with load to be transferred away onto new PTN Zone Substation as part of the committed Preston Conversion Stage 6 project in 2020. Therefore Jemena is not planning any feeder augmentations projects at CN for the forward planning period.

5.11.6 COBURG SOUTH ZONE SUBSTATION (CS)

Background

Coburg South Zone Substation (CS) consists of two 66/22 kV 20/30 MVA transformers and two 22 kV buses supplying seven 22 kV feeder lines. CS supplies areas of Coburg, Coburg East, Moreland, Pascoe Vale and Pascoe Vale South.

Substation limits

Consistent with the ratings listed in Table 5–33, CS zone substation summer and winter capacities are limited by the 66/22 kV transformer thermal limits. It is noted that the transformer 22 kV circuit breakers limit the N secure rating of this station to 45.7 MVA. To manage this N secure risk under peak load conditions, there is an operation instruction in place to transfer load away from CS onto CN feeders by utilising existing emergency feeder transfer capability and demand response using voltage management on days of peak demand during summer.

Table 5–33: Coburg South Zone Substation ratings

	Summer	Winter
Substation N rating	60.0 MVA	60.0 MVA
Substation N-1 rating	42.2 MVA	47.3 MVA

Substation fault levels

Table 5–34 presents CS's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–34: Coburg South Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	11.2 kA	6.7 kA
LV 22 kV	8.5 kA	1.6 kA

Network impact

The load supplied by the substation under 10% POE and 50% POE summer maximum demand conditions already exceeds the substation's N-1 capacity. Based on the 10% POE summer maximum demand, outage of a 66/22 kV transformer will result in involuntary load shedding of up to 15.4 MVA in 2020.

With the proposed load transfer from CS to new PTN Zone Substation as part of the committed Preston Conversion Stage 6 project which is scheduled to be completed in 2020, from summer 2021, there is adequate capacity to meet the anticipated maximum demand for under 10% POE conditions for the forward planning period with both transformers in service.

Figure 5-8 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to substation limits (MVA).

Figure 5-8: Coburg South Zone Substation maximum demand loading

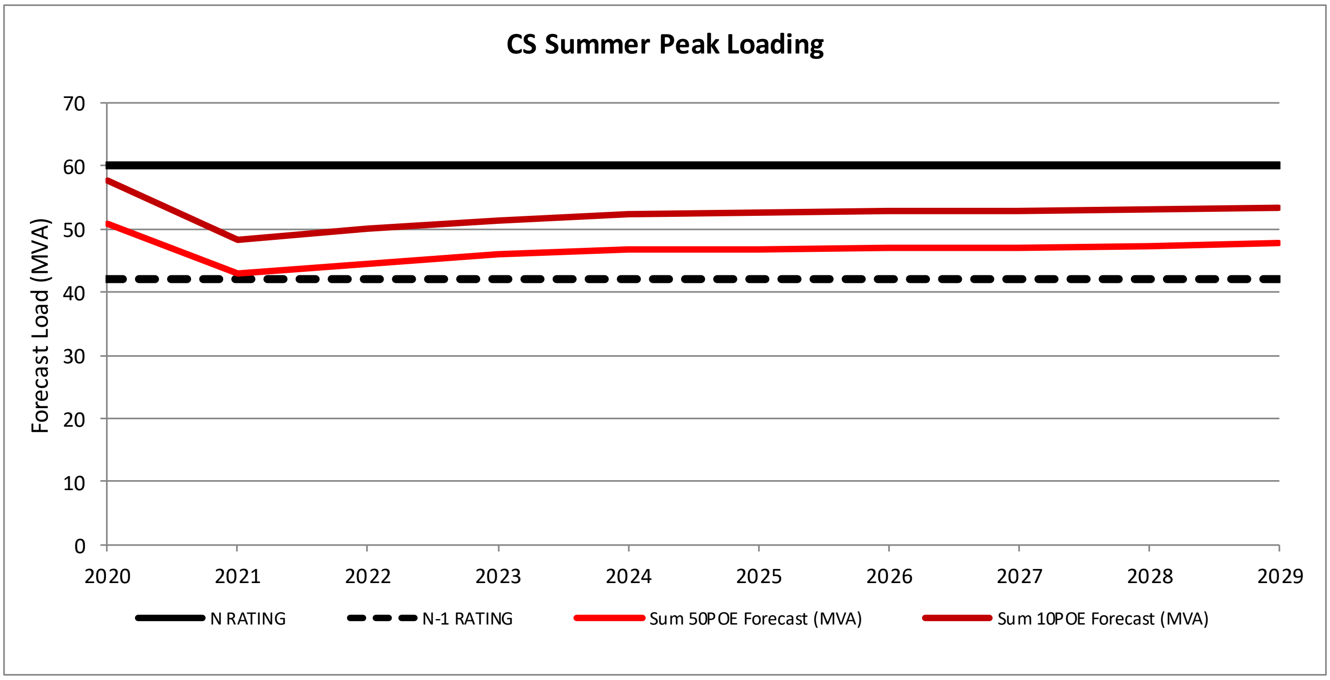

Table 5–35 shows the system normal maximum demand forecast, 95% of which is expected to be reached three hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–35: Coburg South Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	57.6	48.4	50.2	51.4	52.5
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	136%	115%	119%	122%	124%
Max load at risk (MVA)	15.4	6.2	8.0	9.2	10.3
Hours at risk (h)	37	6	10	16	18
EUSE (MWh)	0.7	0.1	0.1	0.2	0.2
Cost of EUSE ($ thousand)	29.8	2.4	4.6	6.9	9.6

The table shows that a load reduction of 15.4 MVA in 2020 will defer any forecast limitation by 12 months.

This substation has no large embedded generation connected to it but has up to 13.5 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

Five options have been considered for managing the identified network limitation:

- Option 1: Transfer load to new Preston Zone Substation (PTN) as part of the Preston conversion program;
- Option 2: Install a new 8 MVAR capacitor bank at CS;
- Option 3: Establish a third transformer at CS. This option will alleviate the emerging constraints;
- Option 4: Establish embedded generation suitably located in the CS supply area; and
- Option 5: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced charges or outage rebates.

Proposed preferred solution

As part of the overall Preston area network development strategy, Jemena has identified that Option 1 will maximise the net economic benefit over the total lifecycle capital cost for the wider area. This option relies on establishing a new Preston Zone Substation (PTN), as part of the committed P Conversion Stage 6 project which is scheduled to be completed in 2020 (see section 5.11.21).

Zone substation replacements

There are relay replacement works planned at CS as described in section 5.4.8.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the seven CS feeders is forecast to reach 63.9% in 2020 and slightly decreasing to 63.5% by 2024.

Feeders CS-02 and CS-05 are the heaviest loaded and are forecast to reach 91% and 84% utilisation respectively by 2022, Jemena is proposing to undertake a feeder augmentation project to manage CS-02 and CS-05 feeder loadings during the forward planning period:

- Augment section of CS-05 and CN-05 by reconductoring approximately 800m of HV 105SR conductors with new 19/3.25AAC conductors on CS-05, and reconductoring approximately 130m of HV 65Cu conductors with new 19/3.25AAC conductors on CN-05. As CN-05 feeder is adjacent to CS-02, augmenting section of CN-05 will provide adequate transfer capability to manage the loading on CS-02. This project is planned to be completed by November 2021, at an estimated cost of $274 thousand. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $18 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.7 COOLAROO ZONE SUBSTATION (COO)

Background

Coolaroo Zone Substation (COO) comprises two 66/22 kV 20/33 MVA transformers and two 22 kV buses supplying six 22 kV feeder lines. COO supplies areas of Coolaroo, Meadow Heights, Greenvale, Roxburgh Park and Oaklands Junction.

With some open paddocks within its supply area, COO is at a higher bushfire risk than most of Jemena's supply area. Jemena is required to install Rapid Earth Fault Current Limiters (REFCL) at COO by 1 May 2023 to comply with the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013 and avoid penalty under the Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017.

Substation limits

Consistent with the ratings presented in Table 5–36, COO's summer and winter capacities are limited by the rating of the 66/22 kV transformer circuit breakers i.e. to maintain secure operation, the total station load should not exceed the rating of each of the transformer circuit breakers.

Table 5–36: Coolaroo Zone Substation ratings

	Summer	Winter
Substation N rating	47.6 MVA	47.6 MVA
Substation N-1 rating	38.0 MVA	39.6 MVA

Substation fault levels

Table 5–37 presents COO's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–37: Coolaroo Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	12.4 kA	7.3 kA
LV 22 kV	8.8 kA	1.7 kA

Network impact

The load supplied by the substation under 10% POE and 50% POE summer maximum demand conditions already exceeds the substation's N-1 capacity. Based on the 10% POE summer maximum demand, outage of a 66/22 kV transformer will result in involuntary load shedding of up to 8.7 MVA in 2020.

With both transformers in service, there is adequate capacity to meet the anticipated maximum demand for 10% POE conditions until 2022, and under 50% POE conditions for the forward planning period.

Figure 5-9 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-9: Coolaroo Zone Substation maximum demand loading

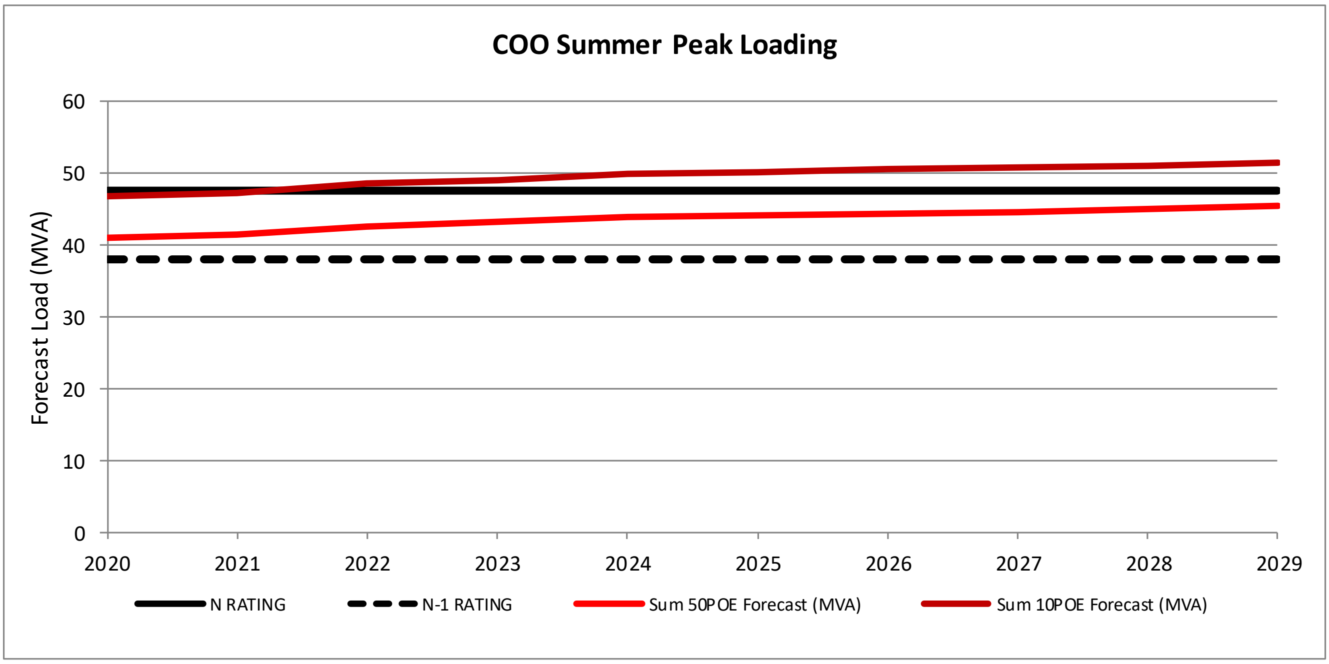

Table 5–38 shows the system normal maximum demand forecast, 95% of which is expected to be reached two hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–38: Coolaroo Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	46.7	47.3	48.5	48.9	49.8
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
10% POE N-1 loading (%)	123%	124%	128%	129%	131%
Max load at risk (MVA)	8.7	9.3	10.5	10.9	11.8
Hours at risk (h)	7	8	11	13	16
EUSE (MWh)	0.1	0.1	0.4	0.6	1.0
Cost of EUSE ($ thousand)	3.0	3.7	16.3	22.9	42.6

The table shows that a load reduction of 8.7 MVA in 2020 will defer any forecast limitation by 12 months.

This substation does not have any large embedded generation connected to it but has up to 14.5 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

Five options have been considered for managing the identified network limitation:

- Option 1: Split the COO 22 kV bus by opening the 22 kV bus-tie circuit breaker when the station load increases beyond 45 MVA;
- Option 2: Permanent load transfers of underground sections to adjacent zone substations (REFCL exemption may be required). This option will reduce the risk of overloading assets at COO;
- Option 3: Establish a new zone substation and transfer some load from COO to the new zone substation (REFCL exemption may be required). This option will reduce the risk of overloading assets at COO;
- Option 4: Establish embedded generation suitably located in the COO supply area; and
- Option 5: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

In order to comply with the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013 and avoid penalty under the Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017, Jemena is proposing to construct a new REFCL zone substation at Greenvale (GVE), transfer a portion of the COO feeders to GVE, and install REFCL at COO by 1 May 2023. Refer to section 5.10 for further information.

Due to the planned transfer of load from COO to GVE as part of the REFCL project, the risk of overloading assets at COO will also be reduced from 1 May 2023. Jemena is proposing to implement Option 1 as an operational measure to manage the system normal (i.e. 'N') risk at COO under peak demand until completion of the REFCL project. While this 22 kV bus split arrangement allows each half of the zone substation to carry up to 33 MVA (transformer thermal limit) for a total zone substation capacity of 66 MVA, the trade-off is an increased consequence if a transformer outage does occur. The zone substation effectively operates as two stations, and a sub-transmission line or transformer outage would therefore result in involuntary load shedding of half of the zone substation load.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the six COO feeders is forecast to reach 70.2% in 2020 and 82.0% by 2024.

COO-11 and COO-22 are the heaviest loaded feeders and are forecast to reach 153.6% and 105.1% utilisation respectively by 2024. COO-11 is one of the critical feeders supplying the area to the west of Craigieburn. Following the commissioning of the second 66kV line to KLO in 2018, load has been permanently transferred from COO-11 to KLO-22 to prevent overloading of feeder COO-11. Load has also been temporarily transferred from COO-11 to SBY-24. Jemena is proposing to undertake two feeder augmentation projects at COO within the forward planning period:

- Mitigate the COO and ST feeder capacity constraint. Based on identified constraints at COO-11 and ST-32, two options have been considered for managing the identified network limitation:

- Option 1: Augment feeders COO-11 and COO-21 to enable load transfer from feeder COO-11 to feeder COO-21 and augment feeders ST-24 and ST-32 to enable load transfer from feeder ST-32 to feeder ST-24 and from feeder ST-33 to feeder ST-32; and
- Option 2: Install a new feeder, likely at COO-23.

The preferred solution is Option 1, to augment feeders COO-11, COO-21, ST-24 and ST-32, at an estimated cost of $2.77 million. This project is required to meet ongoing growth due to significant number of new housing estate developments in the northern growth corridor, and prepare the area for forecasted constraints. Without implementation of this option, up to 3.8 MVA of load reduction will be required under system normal conditions in summer 2020-21.

An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $181 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

- Mitigate the COO-22, ST-32 and ST-33 feeder capacity constraint. Based on identified constraints at COO-22, ST-32 and ST-33, two options have been considered for managing the identified network limitation:
  - Option 1: Reconfigure feeders COO-13, COO-22, ST-31, ST-32 and ST-33; and
  - Option 2: Establish a new zone substation in Craigieburn

A detailed options analysis will be completed in the forward planning period, however at this stage the likely preferred solution is Option 1, to reconfigure feeders COO-13, COO-22, ST-31, ST-32 and ST-33 by November 2024, at an estimated cost of $3.66 million. This project is required to meet ongoing growth due to significant number of new housing estate developments in the northern growth corridor, and prepare the area for forecasted constraints.

An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $239 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.8 EAST PRESTON ZONE SUBSTATION (EP)

Background

East Preston Zone Substation (EP) comprises two 66/6.6 kV 20/27 MVA transformers, two 66/6.6 kV 10/13.5 MVA transformers and six 6.6 kV buses supplying fourteen 6.6 kV feeder lines. The substation is electrically split between two switch houses, EP-A and EP-B. EP supplies areas of Preston, East Preston and Heidelberg West.

EP was originally commissioned in 1920s and underwent extensive refurbishment in the 1960s. Due to age and poor condition, many of the substation and distribution assets require replacement over the next five to ten years to maintain acceptable levels of safety and supply reliability. To ensure continued reliability and to avoid inefficient maintenance works and like-for-like replacements of poor condition assets, Jemena developed a strategic plan for conversion of the Preston and East Preston area from 6.6 kV to 22 kV (Preston conversion program). As part of this program, the existing EP Zone Substation is planned to be retired within the forward planning period as outlined below.

Substation limits

In line with the ratings presented in Table 5–39, the station plant items limiting EP-A's summer and winter capacity is the 66/22 kV transformer thermal limits. Both EP-A and EP-B are operated with an auto-close bus-tie circuit breaker, which will close in the event of a transformer outage, which gives a higher N-1 substation rating.

Table 5–39: East Preston-A Zone Substation ratings

	Summer	Winter
Substation N rating	22.5 MVA	22.5 MVA
Substation N-1 rating	28.5 MVA	28.5 MVA

Consistent with the ratings listed in Table 5–40, EP-B's summer and winter capacities are limited by the 66/22 kV transformer thermal limits.

Table 5–40: East Preston-B Zone Substation ratings

	Summer	Winter
Substation N rating	27.0 MVA	27.0 MVA
Substation N-1 rating	28.5 MVA	28.5 MVA

Substation fault levels

Table 5–41 presents EP-A's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–41: East Preston-A Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	10.5 kA	8.8 kA
LV 6.6 kV	15.9 kA	15.8 kA

Table 5–42 presents EP-B's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–42: East Preston-B Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	10.5 kA	8.8 kA
LV 6.6 kV	15.5 kA	15.4 kA

Network impact

As part of the Preston conversion program, load have already been transferred away from EP to EPN, and further to PTN once it is planned to be completed in 2020. Therefore at both EP-A and EP-B, there is adequate capacity to meet the forecast maximum demand under 10% POE and 50% POE conditions for the forward planning period under N-1 conditions.Figure 5-10 and Figure 5-11 show the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA) at EP-A and EP-B respectively.

Figure 5-10: East Preston-A Zone Substation maximum demand loading

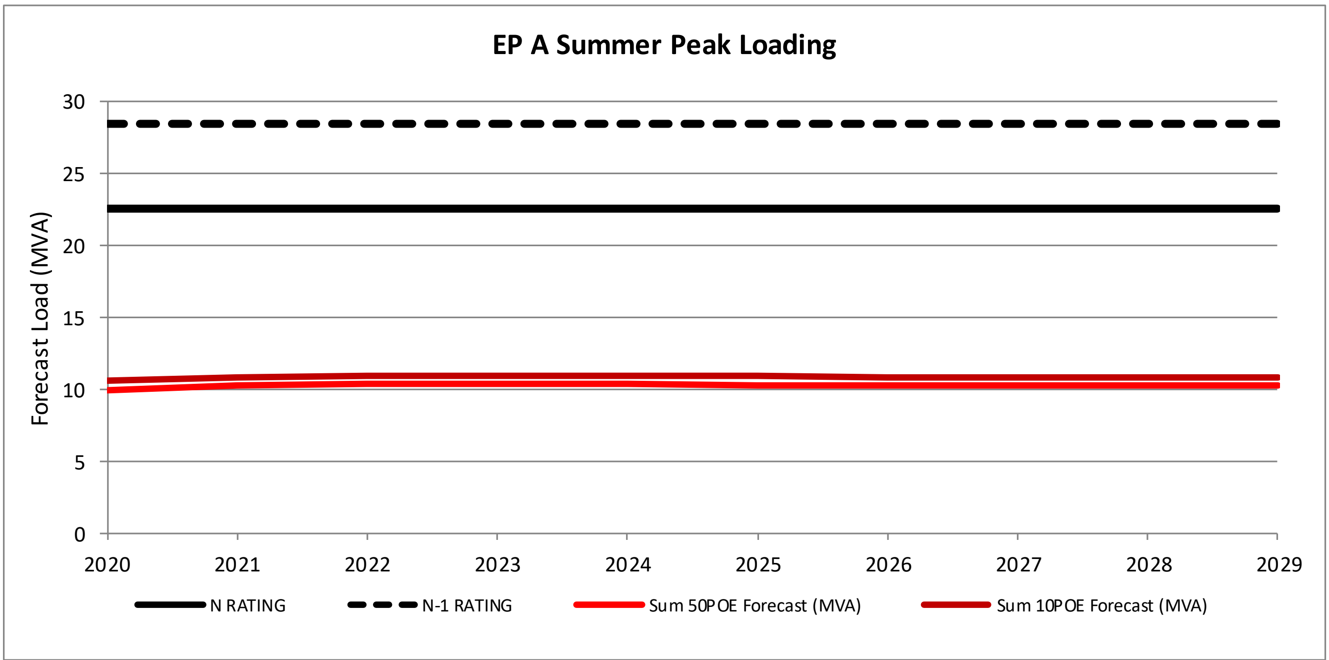

Table 5–43 shows the system normal maximum demand forecast for EP-A, 95% of which is expected to be reached eighteen hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–43: East Preston-A Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	10.6	10.8	11.0	10.9	10.9
Power factor at peak load (p.u)	0.97	0.97	0.97	0.97	0.97
10% POE N-1 loading (%)	37%	38%	38%	38%	38%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

Figure 5-11: East Preston-B Zone substation maximum demand loading

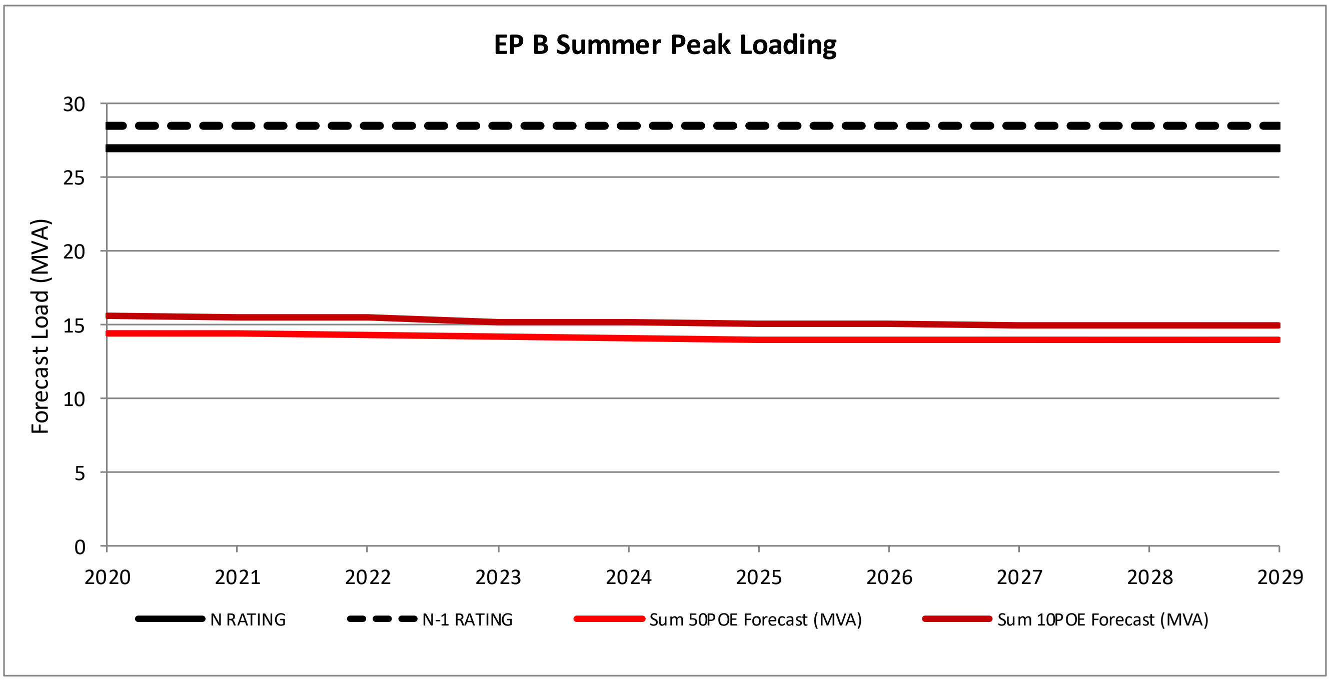

Table 5–44 shows the system normal maximum demand forecast for EP-B, 95% of which is expected to be reached ten hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–44: East Preston-B Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	15.6	15.5	15.5	15.2	15.1
Power factor at peak load (p.u)	0.98	0.98	0.98	0.98	0.98
10% POE N-1 loading (%)	55%	54%	54%	53%	53%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

EP-A and EP-B do not have any large embedded generation connected to them. EP-A has up to 2.1 MVA of emergency transfer capacity and EP-B has up to 4.6 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

There is no forecast load at risk.

Proposed preferred solution

No solution is required to address load at risk.

Zone substation replacements

The Preston conversion program to convert EP and P from 6.6 kV to 22 kV commenced in 2008 and is planned to be completed in stages by 2024. The program comprises six P conversion stages and eight EP conversion stages. The stages, indicative timings and status of the conversion program are:

- P Stage 1, EP Stage 1 and EP Stage 2: Conversion of P and EP feeders and distribution substations was completed in November 2008.
- P Stage 2: Conversion of P feeders and distribution substations was completed in November 2009.
- P Stage 3: Conversion of P feeders and distribution substations was completed in December 2012.
- EP Stage 3: Establishment of a new East Preston Zone Substation (EPN) on the existing EP site, consisting of one 66/22 kV 20/33 MVA transformer and three new EPN feeders, was completed in November 2015.
- P and EP Stage 4: Conversion of P and EP feeders and distribution substations was completed in November 2016.
- P Stage 5: Conversion of P feeders and distribution substations was completed in August 2017.
- P Stage 6: Decommission P and establish a new Preston Zone Substation (PTN) on the existing site, consisting of two 66/22 kV 20/33 MVA transformers. P was decommissioned in November 2017 and PTN is currently in the devlivery phase and is planned to be commissioned in 2020 (refer to Section 5.11.21). Note that this is a committed project.
- EP Stage 5: Conversion of EP feeders and distribution substations is planned for completion by June 2021. This project has an estimated cost of $5.97 million. Note that this project has now completed the RIT-D process. Refer to section 5.7 for further details.

- EP Stage 6: Decommissioning of EP-A and installation of a second EPN 66/22 kV 20/33 MVA transformer is planned for completion by November 2022. This project has an estimated cost of $7.65 million. Note that this project is not yet committed and is therefore subject to the RIT-D process. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $499 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment. However, given that it is part of the ongoing conversion program, and with the completion of the RIT-D process for EP Stage 5, it is unlikely that there will be a viable non-network solution to defer the planned replacements.
- EP Stage 7: Conversion of EP feeders and distribution substations is planned for completion in 2023. This project has an estimated cost of $13.18 million. Note that this project is not yet committed and is therefore subject to the RIT-D process. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $860 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment. However, given that it is part of the ongoing conversion program, it is unlikely that there will be a viable non-network solution to defer the planned replacements.
- EP Stage 8: Conversion of EP feeders and distribution substations and decommissioning of EP-B is planned for completion in 2024. This project has an estimated cost of $8.39 million. Note that this project is not yet committed and is therefore subject to the RIT-D process. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $547 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment. However, given that it is part of the ongoing conversion program, it is unlikely that there will be a viable non-network solution to defer the planned replacements.

Zone substation feeder limitations

Two EP feeders were decommissioned at the end of 2016 as part of EP Conversion Stage 4 described above. The average feeder utilisation across the remaining fourteen EP feeders is forecast to reach 48.4% in 2020 and 52.4% by 2024. It is noted that there are currently fifteen EP feeders as one acts as a back-up feeder with no load. EP-09, EP-34 and EP-37 are the heaviest loaded feeders and are forecast to reach 101%, 103% and 91% utilisation respectively by 2022. Subsequent and remaining stages of the Preston conversion program will address these loading issues and see the remaining feeders converted to 22 kV and supplied out of PTN and EPN Zone Substations.

5.11.9 EAST PRESTON ZONE SUBSTATION (EPN)

Background

The new East Preston Zone Substation (EPN) was commissioned in 2015 and comprises one 66/22 kV 20/30 MVA transformer and one 22 kV bus supplying four 22 kV feeder lines.

Establishing EPN was part of the ongoing strategic plan for conversion of the Preston and East Preston area from 6.6 kV to 22 kV (see Sections 5.11.8 and 5.11.21), to ensure continued reliability and to avoid inefficient maintenance works and like-for-like replacements of poor condition assets.

Substation limits

In line with the ratings presented in Table 5–45, the station plant items limiting EPN's summer and winter capacity is the 66/22 kV transformer thermal limits.

Table 5–45: East Preston Zone Substation ratings

	Summer	Winter
Substation N rating	33.0 MVA	33.0 MVA
Substation N-1 rating	0.0 MVA	0.0 MVA

Substation fault levels

Table 5–46 presents EPN's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–46: East Preston Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	10.0 kA	8.6 kA
LV 22 kV	4.9 kA	1.5 kA

Network impact

As part of the Preston conversion program, some load is planned to be transferred from EPN to PTN once PTN is planned to completed in 2020. Figure 5-12 below has taken this load transfer into account. Based on this planned load transfer, there is adequate capacity to meet the forecast maximum demand under 10% POE and 50% POE conditions at EPN for the forward planning period with the one transformer in service. However, since EPN is a one transformer zone substation, based on the 10% POE summer maximum demand, outage of the 66/22 kV transformer will result in involuntary load shedding of up to 23.6 MVA in 2020.

Figure 5-12 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA) at EPN.

Figure 5-12: East Preston Zone Substation maximum demand loading

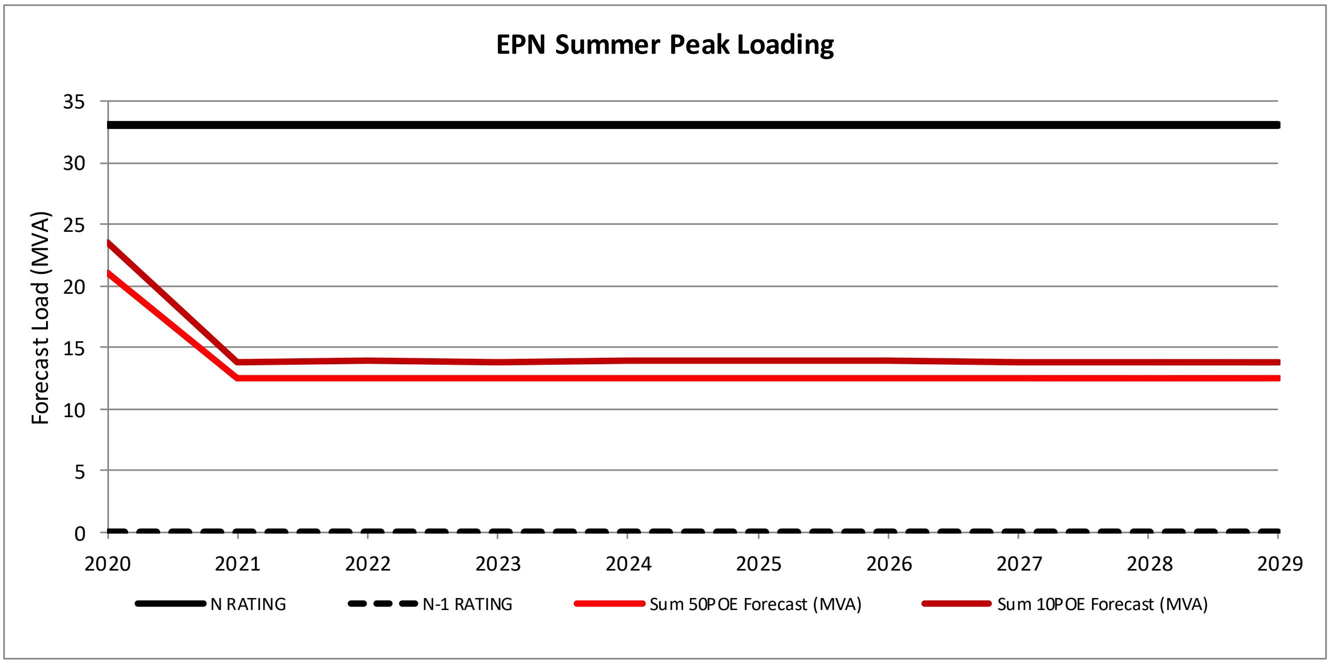

Table 5–47 shows the system normal maximum demand forecast for EPN, 95% of which is expected to be reached eighteen hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–47: East Preston Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	23.6	13.8	13.9	13.8	13.9
Power factor at peak load (p.u)	1.00	0.97	0.97	0.97	0.97
10% POE N-1 loading (%)	N/A	N/A	N/A	N/A	N/A
Max load at risk (MVA)	23.6	13.8	13.9	13.8	13.9
Hours at risk (h)	8,784	8,784	8,784	8,784	8,784
EUSE (MWh)	174.9	91.5	92.0	92.1	92.5
Cost of EUSE ($ thousand)	7,230	3,784	3,803	3,805	3,821

EPN does not have any large embedded generation connected to it. EPN has up to 7.2 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

There is high expected unserved energy forecast at EPN since the station has only one zone substation transformer. Given the 7.2 MVA of emergency transfer capacity, there is 16.4 MVA of load at risk in 2020 that will need to be shed under a loss of the single transformer until the fault is cleared.

Proposed preferred solution

It is proposed that a second transformer will be installed at EP Zone Substation by November 2022 as part of EP Stage 6 of the Preston conversion program as described in section 5.11.8. This augmentation will address the risk of EUSE associated with loss of a single transformer.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the four EPN feeders is only forecast to reach 46.2% in 2020, decreasing to 29.2% by 2024.

With very modest utilisation and a relatively flat demand forecast, other than the works associated with the Preston conversion program, Jemena is not planning any feeder augmentations at EPN for the forward planning period.

5.11.10 ESSENDON ZONE SUBSTATION (ES)

Background

Essendon Zone Substation (ES) presently comprises two 66/11 kV 20/27 MVA transformers and two 11 kV buses supplying eleven 11 kV feeder lines. ES supplies areas of Essendon, Moonee Ponds, Ascot Vale and Niddrie.

Substation limits

ES's summer and winter capacities are limited by the 66/11 kV transformer circuit breakers i.e. to maintain secure operation, the total station load should not exceed each of the transformer circuit breakers. It is noted that the transformer circuit breakers limit the N secure rating of this station to 47.6 MVA.

Table 5–48: Essendon Zone Substation ratings

	Summer	Winter
Substation N rating	54.0 MVA	54.0 MVA
Substation N-1 rating	36.0 MVA	37.3 MVA

Substation fault levels

Table 5–49 presents ES's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–49: Essendon Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	11.8 kA	7.8 kA
LV 11 kV	13.7 kA	2.0 kA

Network impact

The load supplied by the substation under 50% and 10% POE summer maximum demand conditions already exceeds the substation's N-1 capacity. Based on the 10% POE summer maximum demand, outage of a 66/11 kV transformer would result in involuntary load shedding of up to 9.1 MVA in 2020.

With both transformers in service, there is adequate capacity to meet the anticipated maximum demand for the forward planning period.

Figure 5-13 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to substation limits (MVA).

Figure 5-13: Essendon Zone Substation maximum demand forecast loading

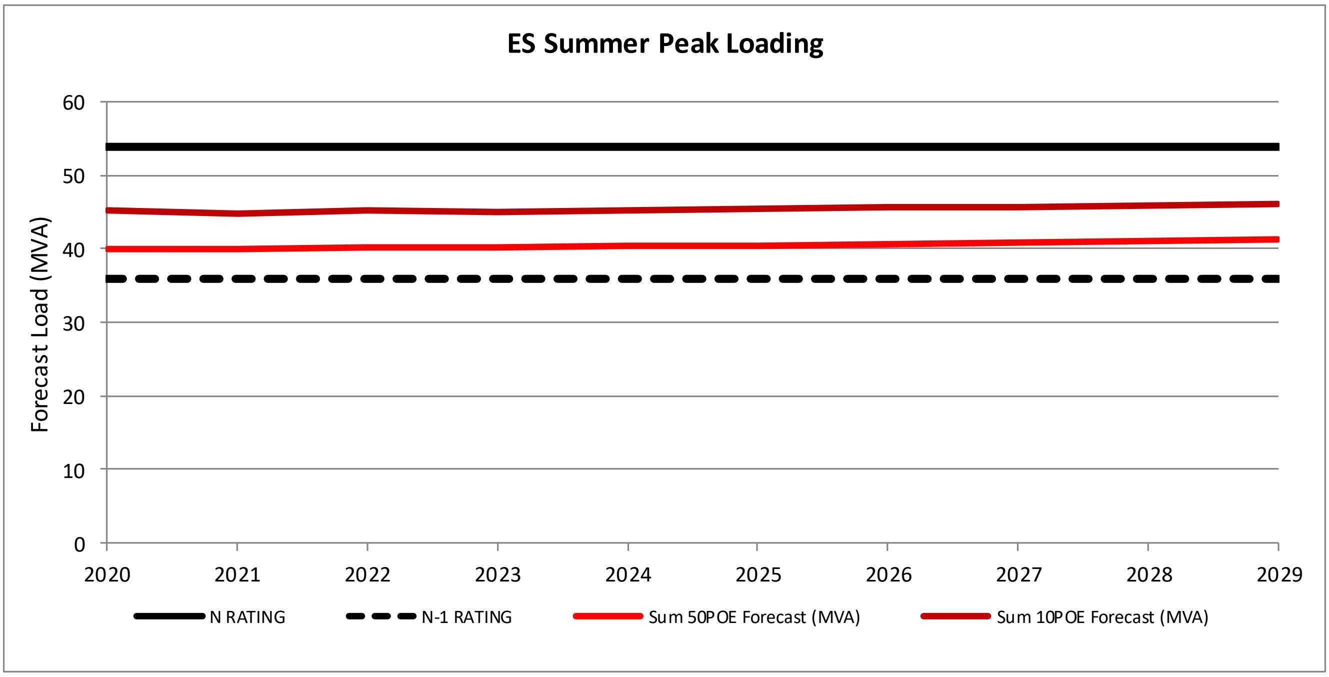

Table 5–50 shows the system normal maximum demand forecast, 95% of which is expected to be reached eleven hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–50: Essendon Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	45.1	44.8	45.2	45.0	45.2
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	125%	125%	126%	125%	126%
Max load at risk (MVA)	9.1	8.8	9.2	9.0	9.2
Hours at risk (h)	26	26	26	26	26
EUSE (MWh)	0.3	0.3	0.3	0.3	0.4
Cost of EUSE ($ thousand)	13.8	12.9	14.3	14.2	14.7

The table shows a load reduction of 9.1 MVA in 2020 will defer any forecast limitation for the forward planning period, even under N-1 conditions.

This substation does not have any large embedded generation connected to it but has up to 8.6 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

Despite some existing load at risk, due to the low probability of a transformer outage concurrent with the peak demand period, there is only a small amount of expected unserved energy each year for the forward planning period. With the load being relatively flat over the next five years, there is insufficient risk to economically justify network augmentation on this basis. However, as described below, there is a plan to replace the two existing transformers with 66/11 kV 20/33 MVA modern equivalent units by March 2020, which will also address the risk of unserved energy.

Zone substation replacements

The existing ES transformers were manufactured in 1965. Due to their age and condition, as indicated by the condition based risk management (CBRM) health indices and poor paper sample degree of polymerisation (DP) transformer tests, the transformers require replacement within the forward planning period to maintain acceptable levels of supply reliability.

Five options have been considered for managing the identified network limitation:

- Option 1: Replace the existing 66/11 kV 20/27 MVA transformers with modern equivalent 20/33 MVA units;
- Option 2: Replace the existing 66/11 kV 20/27 MVA transformers with modern equivalent 20/33 MVA units, and install a third 11 kV switchboard to allow connection of future feeders;
- Option 3: Replace the existing 66/11 kV 20/27 MVA transformers with equivalent units and establish a third transformer and a third 11 kV bus at ES;
- Option 4: Establish embedded generation suitably located in the ES supply area; and
- Option 5: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This would involve the introduction of interruptible loads, as negotiated with customers, by offering incentives in the form of reduced electricity charges or outage rebates.

Jemena has identified that Option 2 will maximise the net economic benefit because it provides the additional transformer capacity required to supply the forecast demand, and minimises the long term costs by using project setup cost synergies for installation of a third 11 kV switchboard. Since all 11 kV circuit breakers at ES are already being utilised, the third 11 kV switchboard is required for connection of future feeders.

This is a committed project that is currently in construction and is due for completion by March 2020.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the eleven ES feeders is forecast to reach 80% in 2020, increasing to 85% in 2024. Feeders ES-15 and ES-22 are the heaviest loaded and are forecast to reach 101.7% and 115.9% utilisation respectively by 2024. Feeder ES-23 is particularly lightly loaded with forecast utilisation of just 26.3% in 2020 and 66.1% by 2024.

To ensure supply security to our customers, Jemena is proposing to undertake the following feeder augmentation project at ES within the forward planning period. This project will offload ES-22 by increasing loading on the underutilised ES-23 feeder:

- Reconfigure ES-23 feeder loads by November 2021, at an estimated cost of $2.6 million. This project involves reconfigure existing feeder ES-23 by installation of approximately 1300 metres of underground cables, 780 metres of new overhead conductor, reconductoring of approximately 1060 metres and thermal uprate of approximately 420 metres of existing overhead conductor. This option will also create a feeder tie between, ES-15, ES-22, ES-24 and NS-11 feeders by extending approximately 780 metres of overhead conductor. As part of the feeder ES-23 extension / reconfiguration, this option also will reconfigure the load between ES-23, ES-15, ES-22, ES-24 and NS-11 feeders. Following reconfiguration, there will be sufficient transfer capacity to meet demand under single contingency conditions. Without implementation of this option up to 1.3 MVA of load reduction at ES will be required under normal operating conditions and 4.6 MVA under outage conditions.

An annual maximum possible payment to non-network service providers to address the risk of EUSE is up to $169 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.11 FAIRFIELD ZONE SUBSTATION (FF)

Background

Fairfield Zone Substation (FF) comprises three 22/6.6 kV 10/13.5 MVA transformers and three 6.6 kV buses supplying six Jemena 6.6 kV feeders. The substation also supplies six CitiPower 6.6 kV feeders. FF supplies areas of Fairfield, Alphington and Ivanhoe.

Station limits

Consistent with the ratings listed in Table 5–51 FF's summer and winter N-1 capacities are limited by a 22 kV overvoltage limit on the 22/6.6 kV transformers.

Table 5–51: Fairfield Zone Station Ratings

	Summer	Winter
Station N rating	40.5 MVA	40.5 MVA
Station N-1 rating	25.7 MVA	31.7 MVA

Substation fault levels

Table 5–52 presents FF's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–52: Fairfield Zone Substation fault levels

	Three phase	Single phase to ground
HV 22 kV	7.6 kA	4.2 kA
LV 6.6 kV	17.8 kA	2.1 kA

Network impact

There is adequate capacity under N-1 conditions to meet the forecast maximum demand for 50% POE conditions until 2023. However the load supplied by the substation under 10% POE summer maximum demand conditions will exceed the substation's N-1 capacity by 2020.

Figure 5-14 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-14: Fairfield Zone Substation maximum demand loading

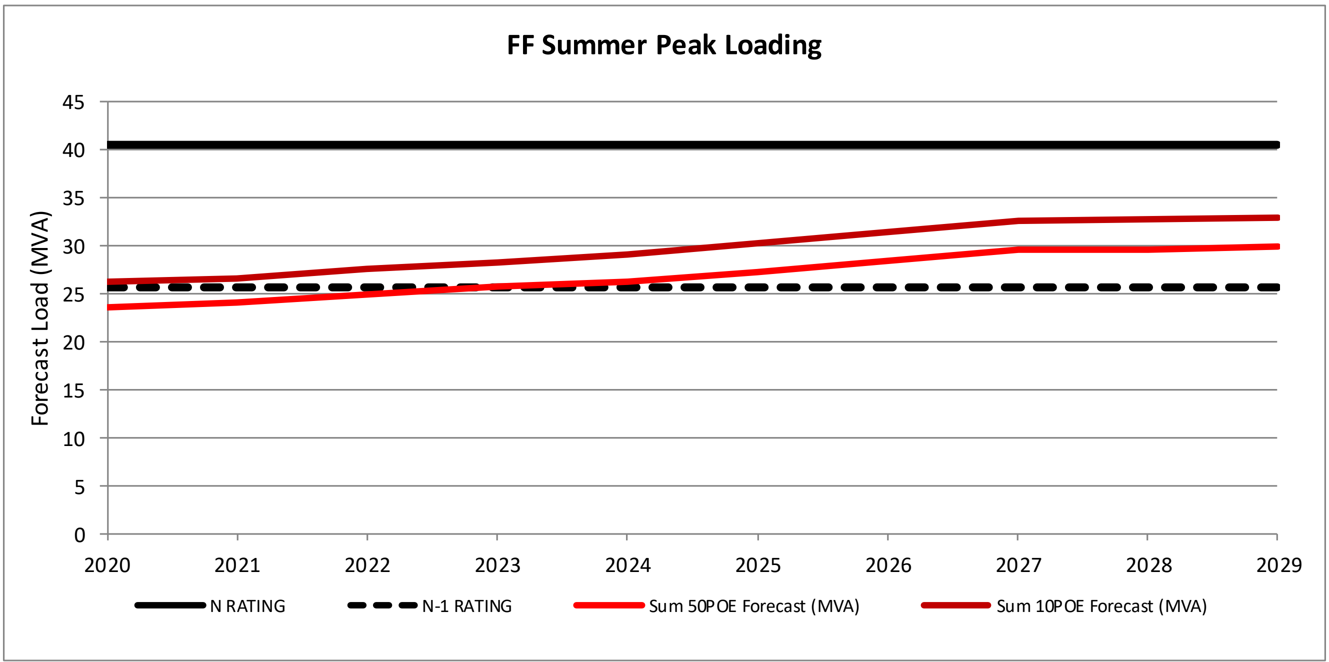

Table 5–53 shows the system normal maximum demand forecast, 95% of which is expected to be reached ten hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–53: Fairfield Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	26.3	26.6	27.5	28.2	29.0
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	102%	103%	107%	110%	113%
Max load at risk (MVA)	0.6	0.9	1.8	2.5	3.3
Hours at risk (h)	1	2	5	6	12
EUSE (MWh)	0.0	0.0	0.0	0.1	0.1
Cost of EUSE ($ thousand)	0.1	0.3	1.2	2.2	4.1

This substation does not have any large embedded generation connected to it, and there is no emergency transfer capacity available in 2019.

Risk mitigation options considered

Despite some emerging load at risk from 2020 onwards, due to the low probability of a transformer outage concurrent with the peak demand period, there is only a small amount of expected unserved energy in 2020 to 2024 in the forward planning period. There is insufficient risk to economically justify network augmentation on this basis.

Proposed preferred solution

No solutions are required.

Zone substation replacements

The existing FF transformers were manufactured in 1955 and due to their age and condition, as confirmed by paper samples taken from the winding leads of the No.1, No.2 and No.3 transformers in 2013 and 2014, will require replacement within the forward planning period to maintain acceptable levels of supply reliability. Much of the distribution substations and network assets within the FF supply area are similarly aged and in a degraded condition requiring replacement.

Three options have been considered to manage the risk associated with the aging transformers at FF:

- Option 1: Replace the existing three 10/13.5 MVA transformers with three new 12/18 MVA transformers;
- Option 2: Replace two of the existing three 10/13.5 MVA transformers with two new 12/18 MVA transformers and keep the third 10/13.5 MVA transformer as a hot spare; and
- Option 3: Replace the existing three 10/13.5 MVA transformers with two new 28.5 MVA transformers.

Jemena has identified that Option 2 maximises net economic benefits of the project whilst achieving an appropriate level of environmental, safety and operational risk and is therefore the preferred option for replacement of the aging transformers. This project has an estimated cost of $12.73 million and is in construction stage and due for completion by June 2020. Note that this is a committed project.

Although there is minimal forecast load at risk in the forward planning period, there are a number of significant residential developments planned for this area including the redevelopment of the former Australian Paper Fairfield (APF) site. It is forecast that this site will require a supply of up to 6.8 MVA by 2024, with a further 6.6 MVA after 2024. Replacement of the third transformer at FF may also be required soon after 2024 to accommodate this load growth (as per Option 1 above). The exact timing of this replacement will be driven by customer requirements.

Zone substation feeder limitations

The feeders supplying Jemena’s customers in the Fairfield and surrounding areas are highly utilised. Following an outage there is insufficient transfer capacity available to meet forecast demand. Additionally, with the ongoing conversion of its neighbouring zone substations, Preston and East Preston, from 6.6 kV to 22 kV, the FF supply area will become an isolated 6.6 kV network. With further expected reductions in emergency transfer capacity to adjacent zone substation under outage conditions, the duration of outages is expected to increase in the Fairfield area following completion of the East Preston conversion.

Jemena’s ultimate plan is to convert the FF distribution network from 6.6 kV to 11 kV. However, this is a longer-term option that will be completed when it is optimally economic to do so. Conversion of FF to 11 kV will provide backup feeder capability to the isolated 11 kV network supplied by Heidelberg Zone Substation (HB) and provide the required capacity to meet the existing and forecast demand at FF. Conversion from 6.6 kV to 11 kV will help with the retirement of aged 6.6 kV assets, which are in poor condition and in need of replacement.

The average summer 10% POE feeder utilisation across Jemena’s six FF feeder lines is forecast to reach 84.3% in 2020, increasing to 120.5% in 2024. Feeders FF-95 and FF-96 are the heaviest loaded and are forecast to reach 299.35% and 95.98% utilisation respectively in 2024. The growth on these two feeders are mainly driven by the redevelopment of the former APF site.

To ensure supply security to our customers, Jemena is proposing to undertake three feeder augmentation projects at FF within the forward planning period. However these projects are specifically driven by a new customer development.

5.11.12 FLEMINGTON ZONE SUBSTATION (FT)

Background

Flemington Zone Substation (FT) comprises two 66/11 kV 20/30 MVA transformers, two 11 kV buses and ten 11 kV feeder lines. It supplies around 15,000 domestic, commercial and industrial customers in the Flemington, Kensington, Ascot Vale and surrounding areas, with major customers including Flemington Race Course and the Melbourne Showgrounds.

Consistent with the ratings in Table 5–54, FT's summer and winter capacities are limited by the 66/11 kV transformer thermal rating i.e. to maintain secure operation, the total station load should not exceed each of the transformer thermal rating. It is noted that the transformer emergency rating limits the N secure rating of this station to 45.0 MVA.

Table 5–54: Flemington Zone Substation ratings

	Summer	Winter
Substation N rating	45.0 MVA	45.0 MVA
Substation N-1 rating	34.8 MVA	34.8 MVA

Substation fault levels

Table 5–55 presents FT's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–55: Flemington Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	16.5 kA	13.1 kA
LV 11 kV	14.5 kA	2.7 kA

Network impact

The load supplied by the substation under 10% POE and 50% POE summer maximum demand conditions exceeds the substation's N-1 capability. Based on the 10% POE summer maximum demand, outage of a 66/11 kV transformer will result in involuntary load shedding of up to 1.3 MVA in 2020.

With both transformers in service, there is adequate capacity to meet the anticipated maximum demand for the forward planning period.

Figure 5-15 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to substation limits (MVA).

Figure 5-15: Flemington Zone Substation maximum demand forecast loading

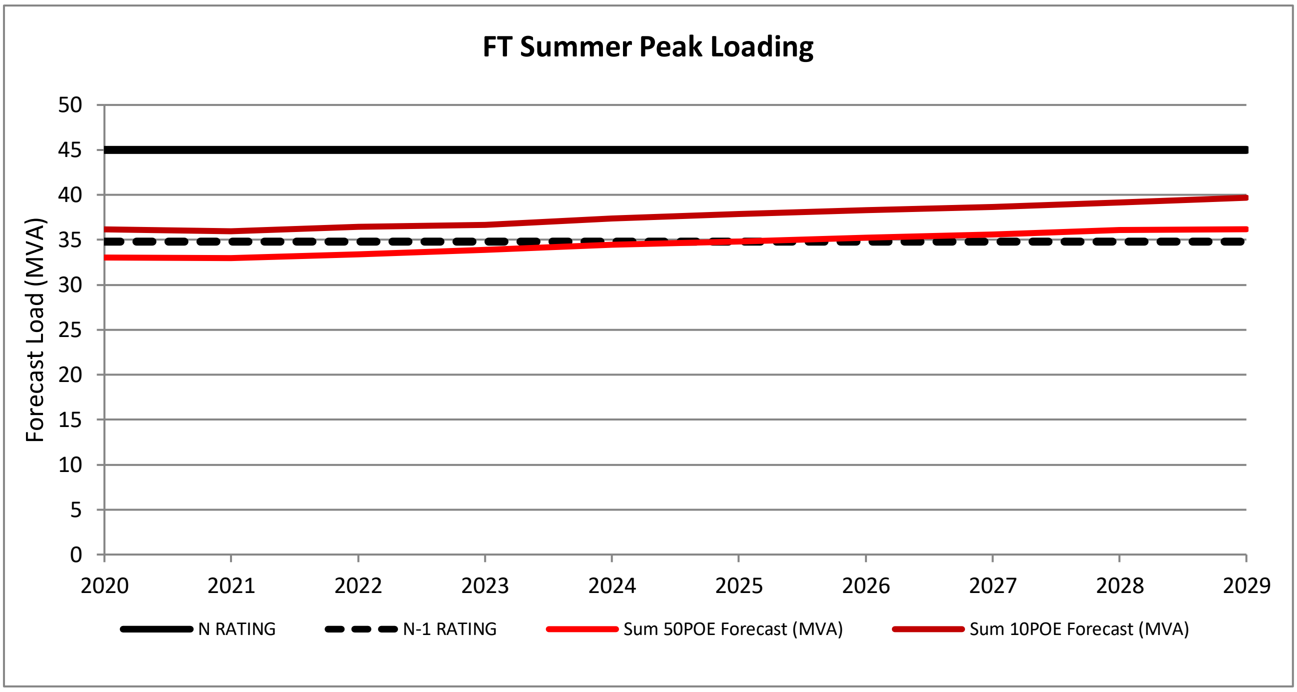

Table 5–56 shows the system normal maximum demand forecast, 95% of which is expected to be reached seven hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–56: Flemington Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	36.1	36.0	36.5	36.7	37.4
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	104%	103%	105%	105%	107%
Max load at risk (MVA)	1.3	1.2	1.7	1.9	2.6
Hours at risk (h)	1	1	2	2	4
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.1	0.1	0.2	0.3	0.7

Risk mitigation options considered

Despite some load at risk following the FT augmentation, due to the low probability of a transformer outage concurrent with the peak demand period and available load transfer capacity (0.9MVA in 2020), there is only a small amount of expected unserved energy each year for the forward planning period. With the load being relatively flat over the next five years, there is insufficient risk to economically justify any further network augmentation.

However, Jemena already has a demand management solution set up pre- augmentation at FT, and is currently working with GreenSync to continue with the existing demand management solution to manage the supply risk under summer 10% POE condition if it is economically justified.

Zone substation replacements

FT is a multi-level indoor zone substation that was originally commissioned in the 1960s using air insulated switchgear (AIS) for the 66 kV assets. Due to its age and condition, many of the primary assets and the protection and control assets are due for replacement over the next five to ten years to maintain acceptable levels of supply reliability and many of these replacements had been completed in 2018 with the previously committed augmentation project. There is no significant replacement project planned in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE FT feeder utilisation across the ten FT feeders is now forecast to reach 66% in 2020 and growing to 70% by 2024.

FT-21 and FT-31 are the heaviest loaded feeders and are forecast to reach 89.0% and 101.0% utilisation respectively by 2024. Load on these feeders can be managed via existing transfers, therefore Jemena is not planning any feeder augmentations at FT for the forward planning period.

5.11.13 FOOTSCRAY EAST ZONE SUBSTATION (FE)

Background

Footscray East Zone Substation (FE) comprises one 66/22 kV 20/30 MVA transformer, one 66/22 kV 20/33 MVA transformer and two 22 kV buses supplying five 22 kV feeder lines. FE supplies areas of Footscray, Footscray East, Yarraville and Spotswood.

Substation limits

Consistent with ratings listed in Table 5–57, FE's summer and winter N-1 capacities are limited by 22 kV transformer circuit breaker and cable limits. It is noted that the transformer circuit breakers limit the N secure rating of this station to 30.5 MVA. To manage this risk under peak load conditions, there is an operation instruction in place to transfer load onto YVE Zone Substation via remote switching on the distribution feeders when the station load exceeds 29 MVA.

Table 5–57: Footscray East Zone Substation Ratings

	Summer	Winter
Substation N rating	61.0 MVA	61.0 MVA
Substation N-1 rating	30.5 MVA	30.5 MVA

Substation fault levels

Table 5–58 presents FE's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–58: Footscray East Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	14.7 kA	10.4 kA
LV 22 kV	9.3 kA	2.2 kA

Network impact

The load supplied by the substation under 50% POE summer maximum demand conditions already exceeds the substation's N-1 capacity. Based on the 10% POE summer maximum demand, outage of a 66/22 kV transformer would result in involuntary load shedding of up to 10.6 MVA in 2020.

With both transformers in service, there is adequate capacity to meet the anticipated maximum demand for the forward planning period (with the 22 kV bus-tie open during periods of peak demand).

Figure 5-16 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-16: Footscray East Zone Substation maximum demand loading

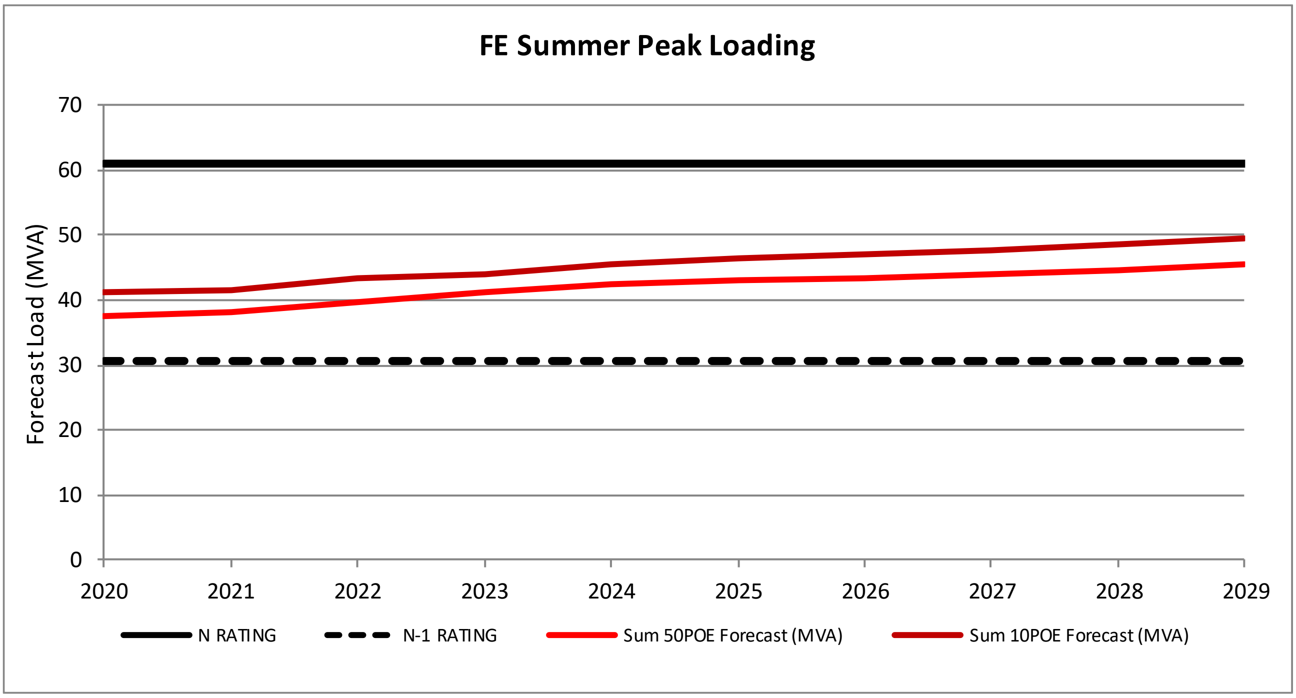

Table 5–59 shows the system normal maximum demand forecast, 95% of which is expected to be reached eight hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–59: Footscray East Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	41.1	41.6	43.3	43.9	45.5
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	135%	136%	142%	144%	149%
Max load at risk (MVA)	10.6	11.1	12.8	13.4	15.0
Hours at risk (h)	93	108	143	207	291
EUSE (MWh)	1.2	1.4	2.1	2.8	4.0
Cost of EUSE ($ thousand)	48.2	57.5	85.5	116.4	165.9

The table shows a load reduction of 10.6 MVA in 2020 will defer any forecast limitation for 12 months.

This substation does not have any large embedded generation connected to it but has up to 22.9 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

Three options have been considered for managing the identified network limitation:

- Option 1: Establish embedded generation suitably located in the FE supply area;

- Option 2: Install third 20/33MVA 66/22kV transformer at FE zone substation; and
- Option 3: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

Despite some existing load at risk, due to the low probability of a transformer outage concurrent with the peak demand period, and sufficient load transfer capacity, there is only a small amount of expected unserved energy each year for the forward planning period. With the moderate load growth over the next five years, there is insufficient risk to economically justify any network augmentation.

Zone substation replacements

Jemena intends to complete two network replacement projects at FE in the forward planning period:

- Replace 22 kV switchgear at FE in 2021. Using our condition based reliability management (CBRM) model, we have identified thirteen 22 kV circuit breakers that are in poor condition and require replacement. These circuit breakers are aged beyond their expected useable life, have a history of failure, and have deteriorated bushings and mechanism problems.

  Four options have been considered to manage the risk associated with the aging 22kV buses and associated switchgear at FE:

  - Option 1: Do nothing, run to fail;
  - Option 2: Increased maintenance and monitoring;
  - Option 3: Full Load Transfer; and
  - Option 4: Replace buses and associated switchgear.

  Jemena has identified that Option 4 to replace the buses and associated switchgear at FE Zone Substation with modern equivalents will address all issues identified at an estimated cost of $5.2 million. It should be noted the RIT-D for this has now been completed (see section 5.7) and the project is expected to be completed by 2021.

- Replace 66 kV 1-2 bus-tie circuit breaker (CB) in November 2020. The existing 1-2 66kV bus-tie CB at FE are no longer supported by the manufacturer and consequently spare components such as 66kV bushings, turbulators, solenoids and mechanism components are no longer available. The lack of spare parts translates to not being able to repair defects and recover from major faults. Furthermore, there has been a defect identified. An inspection of all of these types of breakers has been undertaken and a plant defect notice issued.

  Three options have been considered to manage the risk associated with the aging 66 kV CB at FE:

  - Option 1: Do nothing, run to fail;
  - Option 2: Increased maintenance and monitoring for these types of CBs; and
  - Option 3: Replace 66 kV CB with SF6 dead tank CB.

Jemena has identified that Option 3 to replace the existing 1-2 66kV bus-tie CB at FE zone substation with new modern equivalents and installing them to current standards will address all the condition issues identified and maintain safety, reliability and security of customer supply. This option is seen as the most technically viable and is the preferred option and has an estimated cost of $343 thousand. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $22 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the five FE feeders is forecast to reach 66.5% in 2020, increasing to 81.6% by 2024. FE-06 is the heaviest loaded feeder with utilisation forecast to increase from 86.0% in 2020 to 117.0% in 2024.

To ensure supply security to our customers, Jemena is proposing to undertake the following feeder augmentation project at FE within the forward planning period:

- Augment feeder FE-06, by November 2023, at an estimated cost of $2.8 million. The loading on feeder FE-006 is forecasted to be above its rating by summer 2022 and has limited capability to transfer load during an outage condition. The forecast loading on FE-06 is expected to increase from 83.6% in 2020 to 142.9% in 2025. Without implementation of this project up to 3.3 MVA of load reduction will be required under system normal condition during summer 2024. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $182 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.14 FOOTSCRAY WEST ZONE SUBSTATION (FW)

Background

Footscray West Zone Substation (FW) comprises three 66/22 kV 20/30 MVA transformers and three 22 kV buses supplying eight 22 kV feeder lines. FW supplies areas of Footscray West, Yarraville, Spotswood and Brooklyn.

Substation limits

Consistent with the ratings listed in Table 5–60, FW's summer and winter N-1 capacities are limited by a 66 kV transformer overvoltage limit, a line drop compensation limit and metering limit.

Table 5–60: Footscray West Zone Substation Ratings

	Summer	Winter
Substation N rating	90.0 MVA	90.0 MVA
Substation N-1 rating	70.3 MVA	77.2 MVA

Substation fault levels

Table 5–61 presents FW's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–61: Footscray West Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	17.9 kA	14.8 kA
LV 22 kV	12.7 kA	3.5 kA

Network impact

There is adequate capacity under N-1 conditions to meet the forecast maximum demand for 10% POE and 50% POE conditions for the forward planning period.

Figure 5-17 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to substation limits (MVA).

Figure 5-17: Footscray West Zone Substation maximum demand loading

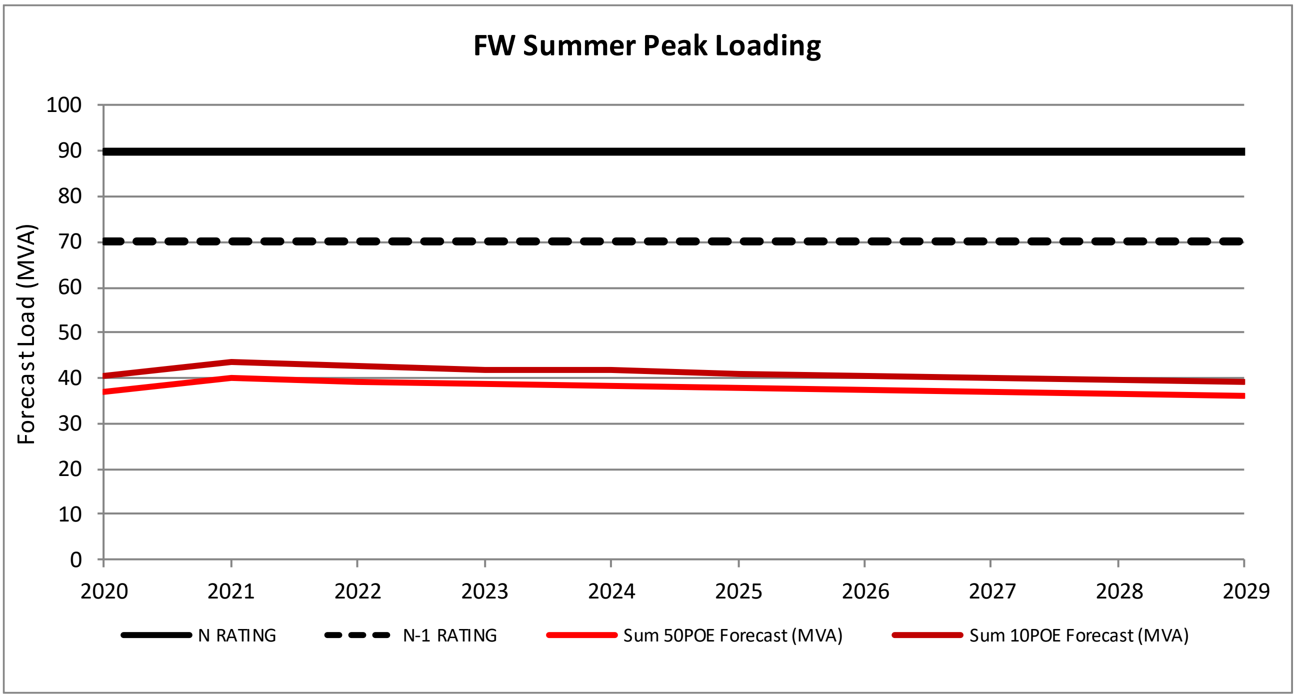

Table 5–62 shows the system normal maximum demand forecast, 95% of which is expected to be reached eight hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–62: Footscray West Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	40.3	43.4	42.7	41.6	41.6
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
10% POE N-1 loading (%)	57%	62%	61%	59%	59%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

This substation does not have any large embedded generation connected to it but has up to 27.1 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

There is no forecast load at risk.

Proposed preferred solution

No solutions are required.

Zone substation replacements

Jemena intends to complete two primary plant related asset replacement projects within the forward planning period:

- Replace 22 kV switchgear by November 2022 - using our condition based reliability management (CBRM) model, we have identified that the three 22 kV buses and nineteen 22 kV circuit breakers at FW are in poor condition and require replacement. These circuit breakers are aged beyond their expected useable life, have a history of failure, and have deteriorated bushings and mechanism problems.

  Four options have been considered to manage the risk associated with the aging buses and switchgear at FW:

  - Option 1: Replace the existing three existing 22 kV buses and associated switchgear with three new 22 kV buses and modern equivalent switchgear;
  - Option 2: Replace the existing three existing 22 kV buses and associated switchgear with two new 22 kV buses and modern equivalent switchgear;
  - Option 3: Replace the existing three existing 22 kV buses and associated switchgear with one new 22 kV buses and modern equivalent switchgear and permanently transfer up to 17 MVA of load to Tottenham (TH) Zone Substation; and
  - Option 4: permanently transfer FW load to neighbouring zone substations and retire FW Zone Substation.

  Jemena is in the process of completing a detailed options assessment to determine the preferred solution as part of the RIT-D process for this project (see section 5.7). The preferred option is Option 2 at an estimated cost of $8.0 million by November 2022.

- Replace 66 kV bus-tie circuit breakers by November 2021 - The existing 1-2 and 2-3 66 kV bus-tie CBs at FW are no longer supported by the manufacturer and consequently spare components such as 66 kV bushings, turbulators, solenoids and mechanism components are no longer available. The lack of spare parts translates to not being able to repair defects and recover from major faults. Three options have been considered to manage the risk associated with the aging 66 kV CB at FW:

  - Option 1 – Do nothing, run to fail;
  - Option 2 – Increased maintenance and monitoring for these types of CBs; and
  - Option 3 – Replace both CBs with SF6 dead tank CBs.

  Jemena has identified that Option 3 to replace the existing 1-2 and 2-3 66kV bus-tie CBs at FW zone substation with new modern equivalents and installing them to current standards will address all the condition issues identified and maintain safety, reliability and security of customer supply. The estimated cost to replace these circuit breakers is $510 thousand. An annual maximum possible payment to non-network service providers to address the increased risk of EUSE resulting from asset failure is approximately $33 thousand (annualised project cost). A non-network solution would need to provide an equivalent level of capacity.

There are also relay replacement works planned at FW as described in section 5.4.8.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the eight FW feeders is forecast to reach 54.6% in 2020, decreasing to 53.2% by 2024.

With modest utilisation and declining demand, Jemena is not planning any feeder augmentations at FW for the forward planning period.

5.11.15 HEIDELBERG ZONE SUBSTATION (HB)

Background

Heidelberg Zone Substation (HB) comprises two 66/11 kV 20/27 MVA transformers and three 11 kV buses supplying seven 11 kV Jemena feeder lines. HB supplies the areas of Heidelberg and Ivanhoe.

Substation limits

Consistent with the ratings listed in Table 5–63, HB's summer and winter N-1 capacities are limited by an overvoltage limit. The HB N rating has been revised down from 54.0 MVA to 45.0 MVA in 2016 following the review of the Jemena substation N secure ratings (refer Section 2.4.2.2)

Table 5–63: Heidelberg Zone Substation Ratings

	Summer	Winter
Substation N rating	45.0 MVA	45.0 MVA
Substation N-1 rating	29.2 MVA	35.6 MVA

Substation fault levels

Table 5–64 presents HB's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–64: Heidelberg Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	8.3 kA	5.6 kA
LV 11 kV	12.0 kA	1.6 kA

Network impact

There is adequate capacity under N-1 conditions to meet the forecast maximum demand under 50% POE conditions for the forward planning period. However the load supplied by the substation under 10% POE summer maximum demand conditions will exceed the substation's N-1 capacity by 2022.

This substation does not have any large embedded generation or emergency transfer capacity.

Figure 5-18: Heidelberg Zone Substation maximum demand loading

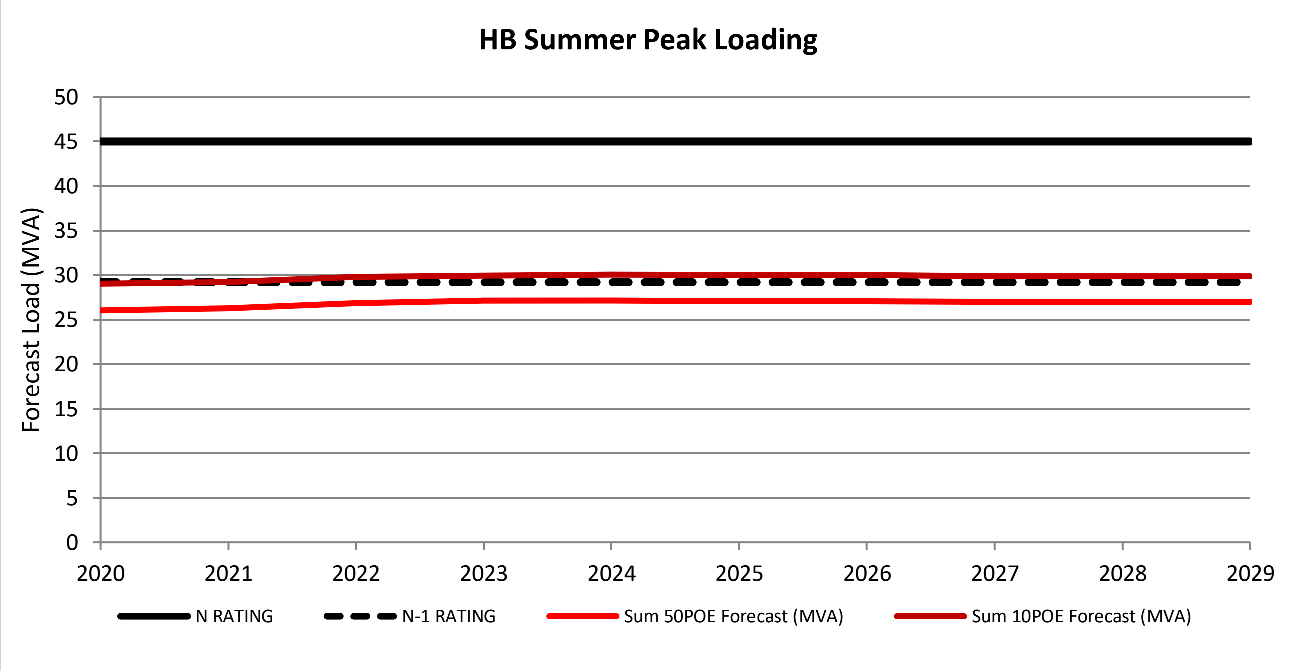

Table 5–65 shows the system normal maximum demand forecast, 95% of which is expected to be reached fifteen hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–65: Heidelberg Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	29.0	29.2	29.8	29.9	30.1
Power factor at peak load (p.u)	0.96	0.96	0.96	0.96	0.96
10% POE N-1 loading (%)	99%	100%	102%	102%	103%
Max load at risk (MVA)	0.0	0.0	0.6	0.7	0.9
Hours at risk (h)	0	0	2	2	4
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	-	0.0	0.1	0.2	0.2

Risk mitigation options considered

Despite some emerging load at risk from 2022 onwards, due to the low probability of a transformer outage concurrent with the peak demand period, there is only a small amount of expected unserved energy each year at the end of the forward planning period. With the load being relatively flat over the next five years, there is insufficient risk to economically justify network augmentation on this basis. However, as described below, there is a plan to replace the two existing transformers with modern equivalent units in 2022, which will also address the risk of unserved energy.

Proposed preferred solution

Despite having some emerging energy at risk from 2022 onwards, augmentation works are not considered economically justified within the forward planning period.

Zone substation replacements

To ensure reliability of supply, Jemena intends to complete two replacement projects at HB in the forward planning period:

- Replace 66 kV 1-2 bus-tie circuit breaker (CB) by November 2020. The existing 1-2 66kV bus-tie CB at HB is no longer supported by the manufacturer and consequently spare components such as 66kV bushings, turbulators, solenoids and mechanism components are no longer available. The lack of spare parts translates to not being able to repair defects and recover from major faults. Furthermore, there has been a defect identified. An inspection of all of these types of breakers has been undertaken and a plant defect notice issued.

  Three options have been considered to manage the risk associated with the aging 66 kV CB at HB:

  - Option 1: Do nothing, run to fail;
  - Option 2: Increased maintenance and monitoring for these types of CBs;
  - Option 3: Replace 66 kV CB with SF6 dead tank CB.

  Jemena has identified that Option 3 to replace the existing 1-2 66kV bus-tie CB at HB zone substation with new modern equivalents and installing them to current standards will address all the condition issues identified and maintain safety, reliability and security of customer supply. This option is seen as the most technically viable and is the preferred option and has an estimated cost of $256 thousand. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $17 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

- Replace 66/11 kV 20/27 MVA transformers by November 2022. The existing HB transformers were manufactured in 1966 and due to their age and condition, as confirmed by a paper moisture content and paper sample degree of polymerisation (DP) test conducted on the No.1 transformer in 2013, the transformers require replacement within the forward planning period to maintain acceptable levels of supply reliability

  The estimated cost to replace the transformers is $9.2 million. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $603 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment. A detailed options analysis will be undertaken as part of the RIT-D process to determine the preferred replacement option (see section 5.7).

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the seven HB feeders is forecast to reach 76.1% in 2020, increasing to 85.1% in 2024. Feeders HB-14, HB-15, HB-22 and HB-24 do not have sufficient back-up transfer capacity to meet the forecast demand under outage conditions.

To ensure supply security to our customers, Jemena is proposing to undertake the following feeder augmentation project at HB within the forward planning period:

- Install a new HB feeder (HB-21) by November 2023, at an estimated cost of $3.0 million. This project involves installing approximately 2.8 kilometres of underground cable and feeder re-configuration works. Following commissioning of the new HB feeder, there will be sufficient transfer capacity under single contingency conditions for HB-14, HB-15, HB-22 and HB-24. Without implementation of this option, up to 5.4 MVA of load reduction at HB will be required under feeder outage conditions.

  An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $197 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.16 KALKALLO ZONE SUBSTATION (KLO)

Background

Kalkallo Zone Substation (KLO) is an AusNet Services owned substation. KLO was constructed by AusNet Services to supply a new industrial park and residential developments in the Merrifield development located along Donnybrook Road. Jemena currently has three feeders in service from KLO: KLO-13, KLO-21 and KLO-22. KLO-22 leads south of KLO and was established in 2013 to offload the developing residential area to the far north of the Somerton Zone Substation (ST) supply area around Mount Ridley Road. The other two feeders were constructed in 2014 for customers in the Donnybrook road development area.

KLO is supplied from South Morang Terminal Station (SMTS). AusNet services have commissioned a new 66 kV line from KLO to Doreen (DRN) in 2018 to complete the SMTS-KLO-DRN 66 kV loop[25]. This augmentation provides a secure 66 kV supply to KLO and significantly improve reliability for loads supplied out of this substation.

KLO substation does not have any embedded generation connected to it but has up to 5.0 MVA of emergency load transfer capacity in 2020.

AusNet Services is required to install Rapid Earth Fault Current Limiters (REFCL) at KLO by 1 May 2023 to comply with the requirements of the Electricity Safety (Bushfire Mitigation) Regulations 2013 and avoid penalty under the Electricity Safety Amendment (Bushfire Mitigation Civil Penalties Scheme) Act 2017. Refer to section 5.10 for additional details.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the three KLO feeders is forecast to reach 37.9% in 2020, increasing to 60.7% by 2024. KLO-13 and KLO-22 are the heaviest loaded feeders and are forecast to reach 83.5% and 90.7% utilisation respectively by 2024. Jemena is proposing to undertake one feeder augmentation project at KLO within the forward planning period:

- Mitigate the KLO and ST feeder capacity constraints. Based on identified constraints at KLO-13, KLO-22 and ST-32, two options have been considered for managing the identified network limitation:
  - Option 1: Augment feeder KLO-21; and
  - Option 2: Establish a new zone substation in Craigieburn

  A detailed options analysis will be completed in the forward planning period, however at this stage the likely preferred solution is Option 1, to augment feeder KLO-21 by November 2022, at an estimated cost of $3.93 million. This project is required to meet ongoing growth due to significant number of new housing estate developments in the northern growth corridor, and prepare the area for forecasted constraints. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $256 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

[25] AusNet Services “Distribution Annual Planning Report 2016-2020” December 2015.

5.11.17 NEWPORT ZONE SUBSTATION (NT)

Background

Newport Zone Substation (NT) comprises two 66/22 kV 35/38 MVA transformers and three 22 kV buses supplying seven 22 kV feeder lines. NT supplies areas of Newport and Williamstown.

Substation limits

Consistent with the rating listed in Table 5–66, NT's summer and winter capacities are limited by the 66/22 kV transformer thermal limits.

Table 5–66: Newport Zone Substation ratings

	Summer	Winter
Substation N rating	57.0 MVA	57.0 MVA
Substation N-1 rating	41.5 MVA	41.5 MVA

Substation fault levels

Table 5–67 presents NT's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–67: Newport Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	14.4 kA	13.5 kA
LV 22 kV	12.2 kA	2.0 kA

Network impact

With all transformers in service, and even under N-1 conditions, there is adequate capacity to meet the forecast maximum demand under 10% POE and 50% POE conditions for the forward planning period.

Figure 5-19 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-19: Newport Zone Substation maximum demand loading

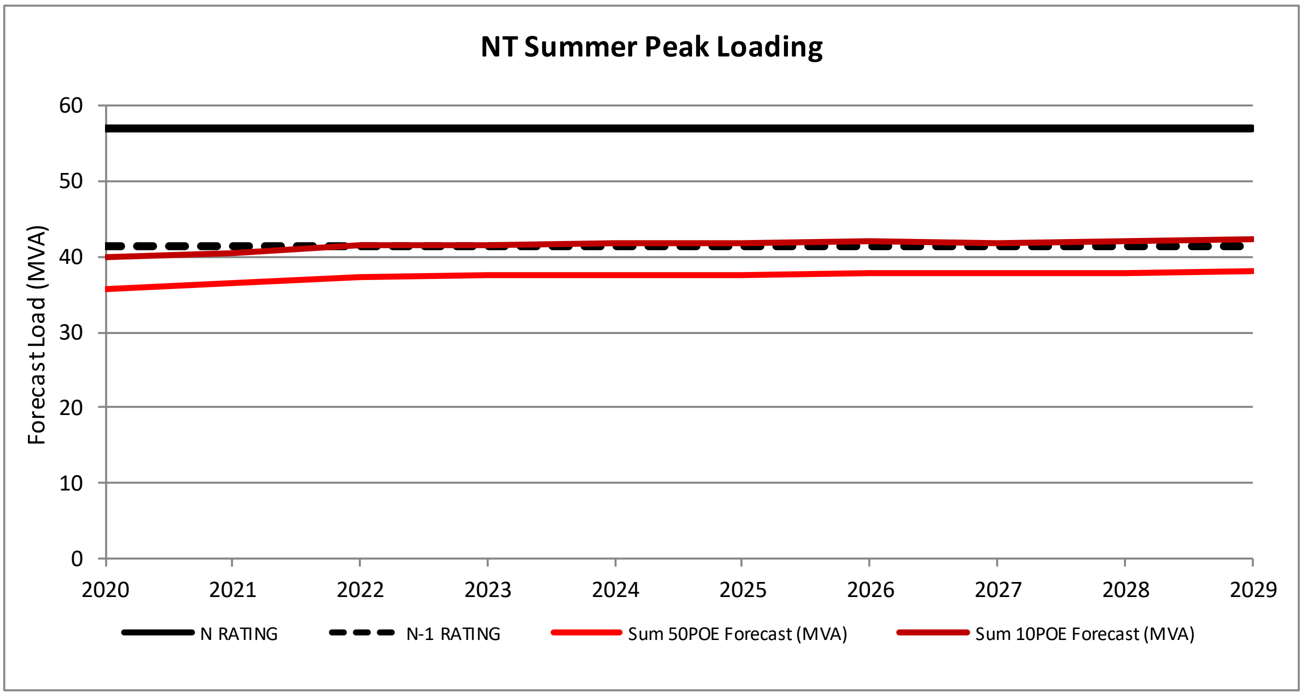

Table 5–68 shows the system normal maximum demand forecast, 95% of which is expected to be reached five hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–68: Newport Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	40.1	40.6	41.5	41.5	41.8
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
10% POE N-1 loading (%)	97%	98%	100%	100%	101%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.3
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0	0	0	0	0

This substation does not have any large embedded generation connected to it but has up to 6.1 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

Despite having a small amount of load at risk, due to the low probability of a transformer outage concurrent with the peak demand period, there is a negligible amount of expected unserved energy each year for the forward planning period.

Proposed preferred solution

No solutions are required.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the seven NT feeders is forecast to reach 63.4% in 2020 increasing to 68.7% by 2024. NT-17 is already operating above its N-rating and is currently managed by temporary feeder transfers. Based on the current demand forecast, NT-15 and NT-17 will be loaded to 90% and 118% by 2022/23. To ensure supply security to our customers, Jemena is proposing to undertake the following feeder augmentation project at NT within the forward planning period:

- Augment feeder NT-11 in 2022 to address capacity constraint on feeder NT-15, NT-17 and NT-11 at an estimated cost of $2.99 million. Without implementation of this project, up to 1.7 MVA of load reduction would be required under system normal conditions.

An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $195 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.18 NORTH ESSENDON ZONE SUBSTATION (NS)

Background

North Essendon Zone Substation (NS) comprises three 22/11-6.6 kV 12/18 MVA dual winding transformers and three 11 kV buses supplying ten Jemena 11 kV feeders. The substation also supplies two CitiPower 11 kV feeders. NS supplies the areas of North Essendon, Strathmore, Moonee Ponds and Ascot Vale.

Substation limits

Consistent with ratings listed in Table 5–69, NS's summer and winter capacities are limited by the 22/11 kV transformer thermal limits.

Table 5–69: North Essendon Zone Substation ratings

	Summer	Winter
Substation N rating	54.0 MVA	54.0 MVA
Substation N-1 rating	36.0 MVA	36.0 MVA

Substation fault levels

Table 5–70 presents NS's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–70: North Essendon Zone Substation fault levels

	Three phase	Single phase to ground
HV 22 kV	5.6 kA	2.5 kA
LV 11 kV	9.7 kA	1.6 kA

Network impact

There is adequate capacity under N-1 conditions to meet the forecast maximum demand for 50% POE conditions for the forward planning period. However the load supplied by the substation under 10% POE summer maximum demand conditions already exceeds the substation's N-1 capacity. Based on the 10% POE summer maximum demand, outage of a 22/11 kV transformer will result in involuntary load shedding of up to 4.5 MVA in 2020.

With all three transformers in service, there is adequate capacity to meet the anticipated maximum demand for the forward planning period.

Figure 5-20 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-20: North Essendon Zone Substation maximum demand loading

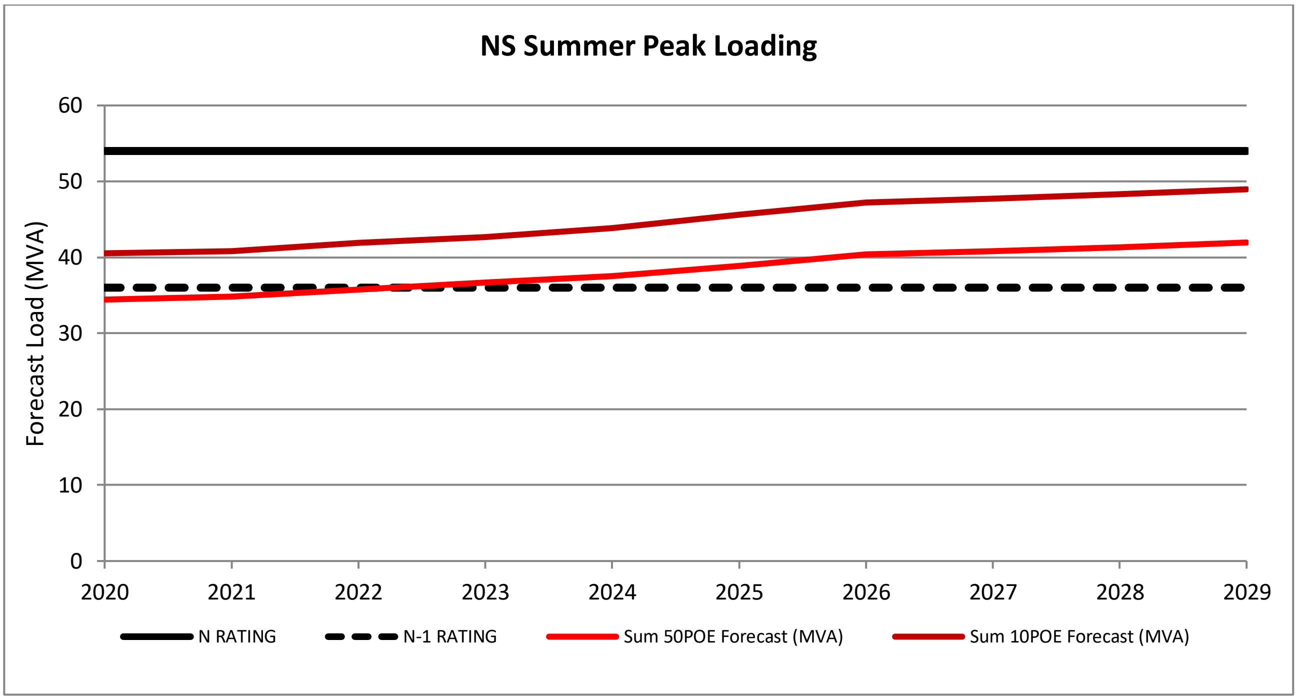

Table 5–71 shows the system normal maximum demand forecast, 95% of which is expected to be reached ten hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–71: North Essendon Zone Substation loading risk and limitation cost

	2019	2020	2021	2022	2023
10% POE MD (MVA)	40.5	40.8	41.9	42.7	43.9
Power factor at peak load (p.u)	0.96	0.96	0.96	0.96	0.96
10% POE N-1 loading (%)	113%	113%	117%	119%	122%
Max load at risk (MVA)	4.5	4.8	5.9	6.7	7.9
Hours at risk (h)	6	7	9	12	19
EUSE (MWh)	0.1	0.1	0.2	0.2	0.3
Cost of EUSE ($ thousand)	4.1	4.7	7.1	9.3	13.8

The table shows that a load reduction of 4.5 MVA in 2020 will defer any forecast limitation by 12 months.

This substation does not have any large embedded generation connected to it but has up to 5 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

Despite having a small amount of load at risk, due to the low probability of a transformer outage concurrent with the peak demand period, there is a negligible amount of expected unserved energy each year for the forward planning period.

Proposed preferred solution

No solutions are required.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the ten NS feeders is forecast to reach 68.1% in 2020, increasing to 77.1% by 2024. Feeders NS-11, NS-15, NS-17 and NS-18 are the heaviest loaded feeders with utilisation forecast to reach 100.8%, 87.4%, 93.4% and 119.6% in 2024.To ensure supply security to our customers, Jemena is proposing to undertake the following feeder augmentation projects at NS within the forward planning period:

- Augment feeder NS-18 by November 2023 at an estimated cost of $1.28 million. This project involves installation of approximately 0.8 kilometres of underground cable, thermal capacity upgrades and feeder load reconfigurations to meet forecast demand growth in the area. Without implementation of this project up to 0.5 MVA of load reduction would be required under system normal conditions and up to 4.7 MVA under outage conditions.

  An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $84 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.19 NORTH HEIDELBERG ZONE SUBSTATION (NH)

Background

North Heidelberg Zone Substation (NH) comprises two 66/22 kV 20/30 MVA transformers, one 66/22 kV 20/33 MVA transformer and three 22 kV buses supplying ten 22 kV feeder lines. NH supplies areas of Yallambie, Viewbank, Macleod, Rosanna, Heidelberg Heights and Heidelberg West.

Substation limits

Consistent with the ratings listed in Table 5–72, NH's summer and winter capacities are limited by the 66/22 kV transformer thermal limits.

Table 5–72: North Heidelberg Zone Substation ratings

	Summer	Winter
Substation N rating	93.0 MVA	93.0 MVA
Substation N-1 rating	75.2 MVA	76.0 MVA

Substation fault levels

Table 5–73 presents NH's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–73: North Heidelberg Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	11.3 kA	6.1 kA
LV 22 kV	11.1 kA	2.0 kA

Network impact

There is adequate capacity under N-1 conditions to meet the forecast maximum demand for 10% POE and 50% POE conditions for the forward planning period.

Figure 5-21 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-21: North Heidelberg Zone Substation maximum demand loading

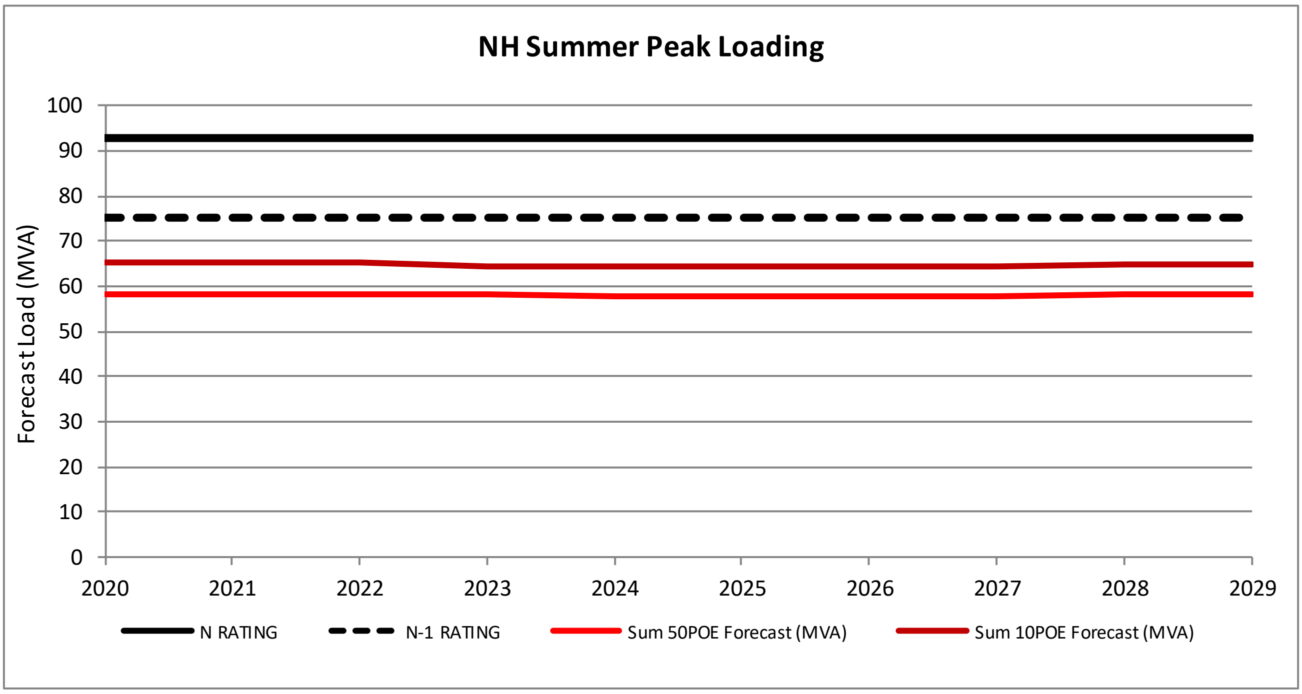

Table 5–74 shows the system normal maximum demand forecast, 95% of which is expected to be reached ten hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–74: North Heidelberg Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	65.4	65.1	65.2	64.3	64.3
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	87%	87%	87%	86%	86%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

This substation has 1.5 MW of large embedded generation connected to it and has up to 9.5 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

There is no forecast load at risk.

Proposed preferred solution

No solutions are required.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average feeder utilisation across the ten NH feeders is forecast to reach 58.1% in 2020 and 58.5% in 2024.

The heaviest loaded feeder is NH-02, which is forecast to reach utilisation of 101.7% in 2024. However the peak load on this feeder is predominately caused on by traction load with insufficient risk to justify network augmentation in the forward planning period.

5.11.20 PASCOE VALE ZONE SUBSTATION (PV)

Background

Pascoe Vale Zone Substation (PV) comprises two 66/11 kV 20/33 MVA transformers, one 66/11 kV 10 MVA and three 11 kV buses supplying nine 11 kV feeder lines. PV supplies areas of Pascoe Vale, Glenroy, Strathmore and Oak Park.

Substation limits

Consistent with the ratings listed in Table 5–75, PV's summer and winter capacities are limited by the 66/11 kV transformer thermal limits.

Table 5–75: Pascoe Vale Zone Substation ratings

	Summer	Winter
Substation N rating	64.0 MVA	64.0 MVA
Substation N-1 rating	45.6 MVA	45.6 MVA

Substation fault levels

Table 5–76 presents PV's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–76: Pascoe Vale Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	11.1 kA	7.1 kA
LV 11 kV	12.5 kA	1.6 kA

Network impact

There is adequate capacity under N-1 conditions to meet the forecast maximum demand for 10% POE and 50% POE conditions for the forward planning period. Accordingly, no substation capacity augmentation is planned.

Figure 5-22 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to substation limits (MVA).

Figure 5-22: Pascoe Vale Zone Substation maximum demand loading

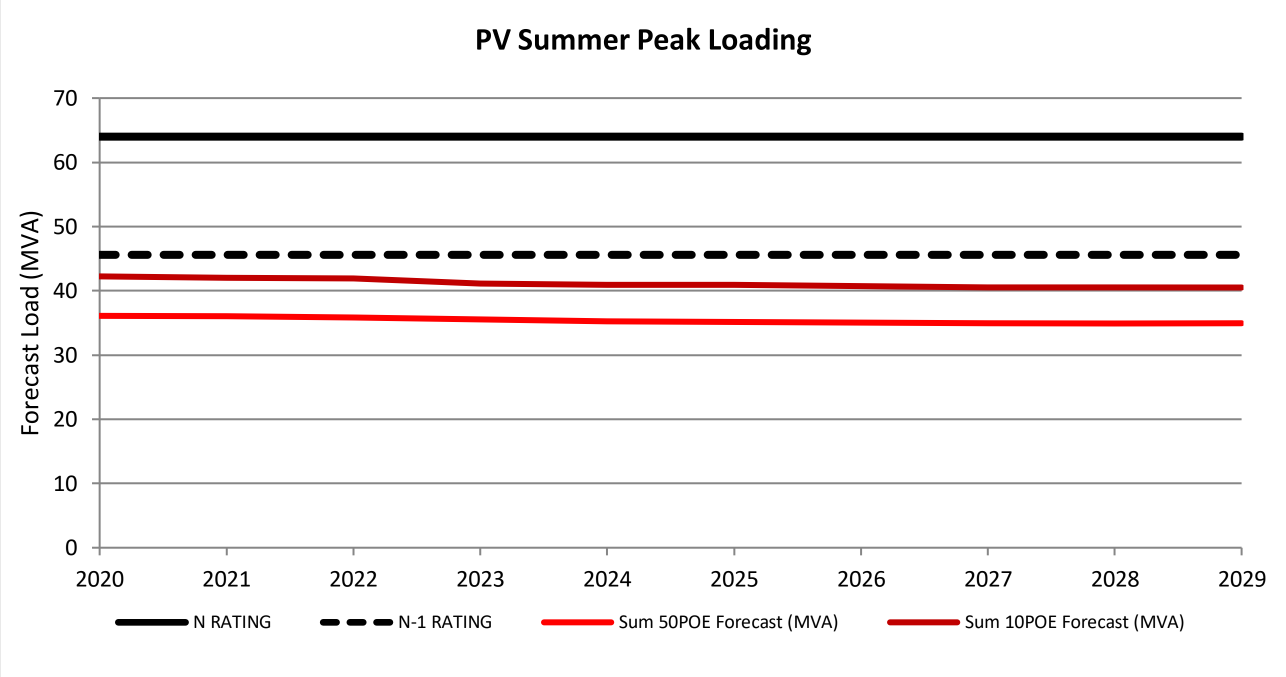

Table 5–77 shows the system normal maximum demand forecast, 95% of which is expected to be reached six hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–77: Pascoe Vale Zone Substation loading risk and limitation cost

	2019	2020	2021	2022	2023
10% POE MD (MVA)	42.2	42.0	41.9	41.2	41.0
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
10% POE N-1 loading (%)	93%	92%	92%	90%	90%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	-	-	-	-	-

This substation does not have any large embedded generation connected to it but has up to 1.5 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

There is no forecast load at risk.

Proposed preferred solution

No solutions are required.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the nine PV feeders is forecast to reach 76.2% in 2020 and 75.2% in 2024.

PV-13, PV-14 and PV-22 are the heaviest loaded feeders and are forecast to reach 91.7%, 92.9% and 92.2% utilisation respectively by 2024. Load on these feeders can be managed via existing transfers, therefore Jemena is not planning any feeder augmentations at PV for the forward planning period.

5.11.21 PRESTON ZONE SUBSTATION (P)

Background

Preston Zone Substation (P) previously supplied areas of Preston and was comprised of two 66/6.6 kV 20 MVA transformers and two 6.6 kV buses supplying five 6.6 kV feeder lines. P was decommissioned in November 2017 as part of the Preston Conversion Stage 6 project (as described in Section 5.11.8). The remaining load was transferred to EPN Zone Substation. The new 66/22 kV Preston Zone Substation (PTN) on the existing Preston site is currently in the delivery phase and is expected to be completed in 2020.

5.11.22 SOMERTON ZONE SUBSTATION (ST)

Background

Somerton Zone Substation (ST) is a fully developed substation comprising three 66/22 kV 20/33 MVA transformers and three 22 kV buses supplying twelve 22 kV feeder lines. ST supplies areas of, and surrounding, Somerton, Campbellfield, Craigieburn and Roxburgh Park.

Substation limits

Consistent with the ratings listed in Table 5–78, ST's summer and winter capacities are limited by the transformer 22 kV circuit breaker limits.

Table 5–78: Somerton Zone Substation Ratings

	Summer	Winter
Substation N rating	95.2 MVA	95.2 MVA
Substation N-1 rating	79.7 MVA	89.3 MVA

Substation fault levels

Table 5–79 presents ST's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–79: Somerton Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	12.3 kA	10.6 kA
LV 22 kV	12.0 kA	2.1 kA

Network impact

There is adequate capacity to meet the forecast maximum demand under N-1 conditions for 50% POE conditions until 2027. The 10% POE summer maximum demand is forecast to exceed the substation's N-1 capacity from 2020, and an outage of a 66/22 kV transformer would result in involuntary load shedding of up to 0.1 MVA in 2020.

Figure 5-23 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to substation limits (MVA).

Figure 5-23: Somerton Zone Substation Maximum Demand Loading

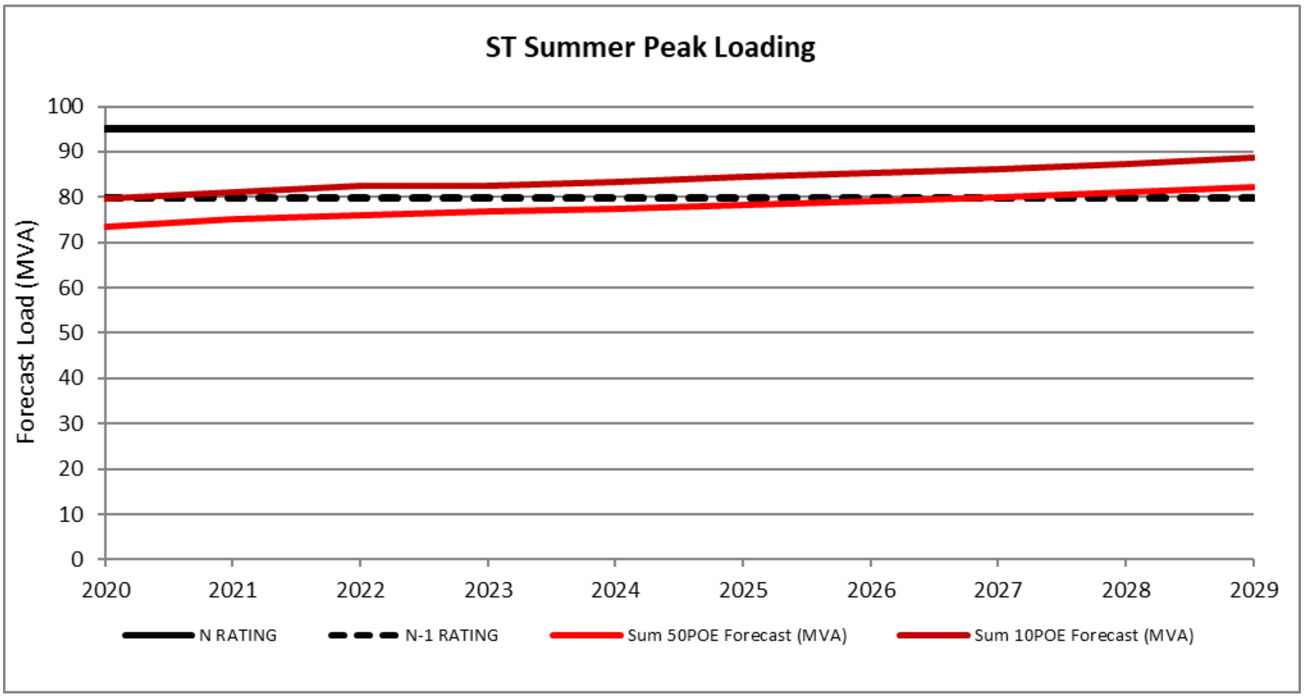

Table 5–80 shows the system normal maximum demand forecast, 95% of which is expected to be reached ten hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–80: Somerton Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	79.8	81.1	82.4	82.5	83.4
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	100%	102%	103%	104%	105%
Max load at risk (MVA)	0.1	1.4	2.7	2.8	3.7
Hours at risk (h)	0	1	2	2	3
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.3	0.7	0.7	1.2

This substation does not have any large embedded generation connected to it but has up to 15.6 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

Somerton is one of three zone substations which supply the fast developing Craigieburn area. Options considered to manage the emerging network risk in the Northern Growth Corridor are outlined below.

Six options have been considered for managing the identified network limitation:

- Option 1: Establish a new zone substation in Craigieburn (CBN). This option will provide sufficient transformation and distribution capacity to meet anticipated load growth in the Craigieburn and Roxburgh Park areas, to alleviate the emerging constraints;
- Option 2: Permanent load transfers to adjacent zone substations to reduce the risk of overloading assets at ST;
- Option 3: Establish a third bus and two new feeder lines from Kalkallo Zone Substation (KLO) to defer the need for CBN;
- Option 4: Establish a third bus and two new KLO feeder lines, as per Option 3, and also establish a third bus and two new feeder lines from Coolaroo Zone Substation (COO), to supply the new load growth areas;
- Option 5: Establish embedded generation suitably located in the ST supply area; and
- Option 6: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

Due to sufficient emergency transfer capacity and the relatively low cost of EUSE, augmentation to alleviate the limitation at COO is not justified in the forward planning period. Jemena is proposing to implement option 2 to reduce the load on ST zone substation.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the twelve ST feeders is forecast to reach 53.8% in 2020, increasing to 59.3% in 2024. Feeders ST-32 and ST-33 are the heaviest loaded with utilisation forecast to reach 142.7% and 105.5% respectively by 2024.

Despite the relatively low average utilisation levels of ST feeders, there is a significant limitation emerging on the ST-32 and ST-33 feeders. This feeder supplies the rapidly developing residential area to the north-west of ST. In the short term, this risk will be managed by load transfers to KLO and reconfiguring the ST feeders.

Jemena is planning to undertake the following two feeder augmentation projects in the forward planning period:

- Mitigate the KLO and ST feeder capacity constraints. Based on identified constraints at KLO-13, KLO-22 and ST-32, two options have been considered for managing the identified network limitation:
  - Option 1: Augment feeder KLO-21; and
  - Option 2: Establish a new zone substation in Craigieburn

A detailed options analysis will be completed in the forward planning period, however at this stage the likely preferred solution is Option 1, to augment feeder KLO-21 by November 2022, at an estimated cost of $3.93 million. This project is required to meet ongoing growth due to significant number of new housing estate developments in the northern growth corridor, and prepare the area for forecasted constraints. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $256 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

- Mitigate the COO and ST feeder capacity constraints. Based on identified constraints at COO-22, ST-32 and ST-33, two options have been considered for managing the identified network limitation:
  - Option 1: Reconfigure feeders COO-13, COO-22, ST-31, ST-32 and ST-33; and
  - Option 2: Establish a new zone substation in Craigieburn

  A detailed options analysis will be completed in the forward planning period, however at this stage the likely preferred solution is Option 1, to reconfigure feeders COO-13, COO-22, ST-31, ST-32 and ST-33 by November 2024, at an estimated cost of $3.66 million. This project is required to meet ongoing growth due to significant number of new housing estate developments in the northern growth corridor, and prepare the area for forecasted constraints. An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $239 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.23 SUNBURY ZONE SUBSTATION (SBY)

Background

Sunbury Zone Substation (SBY) comprises two 66/22 kV 10/16 MVA transformers, one 66/22 kV 20/33 MVA transformer and three 22 kV buses supplying seven 22 kV feeder lines. SBY supplies the areas of Sunbury, Diggers Rest, Bulla, Clarkefield and Gisborne South. The 20/33MVA transformer was commissioned in November 2018 which replaced the old 10 MVA transformer.

The SBY supply area has seen strong demand growth in the past ten years and the substation has become much more critical than its original design allowed for. It is now a key switching substation for five sub-transmission lines, three of which are owned by Powercor and two by Jemena. As a result of urban sprawl and the recent rezoning of the Urban Growth Boundary we expect to see continued strong demand growth in the areas currently supplied by SBY. As a substation on the urban fringe, the SBY supply area is at a higher bushfire risk than most of Jemena's supply area.

Substation limits

Consistent with the ratings listed in Table 5–81, SBY's summer and winter capabilities will be limited by 66/22kV transformer thermal limits

Table 5–81: Sunbury Zone Substation Ratings

	Summer	Winter
Substation N rating	65.0 MVA	65.0 MVA
Substation N-1 rating	38.0 MVA	38.0 MVA

Substation fault levels

Table 5–82 presents SBY's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–82: Sunbury Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	7.1 kA	4.0 kA
LV 22 kV	7.8 kA	1.6 kA

Network impact

Figure 5-24 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to substation limits (MVA). Despite strong continued growth in the forecast maximum demand for the SBY supply area, load is not expected to be at risk under system normal conditions within the forward planning period. The N-1 load at risk can be managed using available load transfer capacity to SHM.

Figure 5-24: Sunbury Zone Substation maximum demand loading

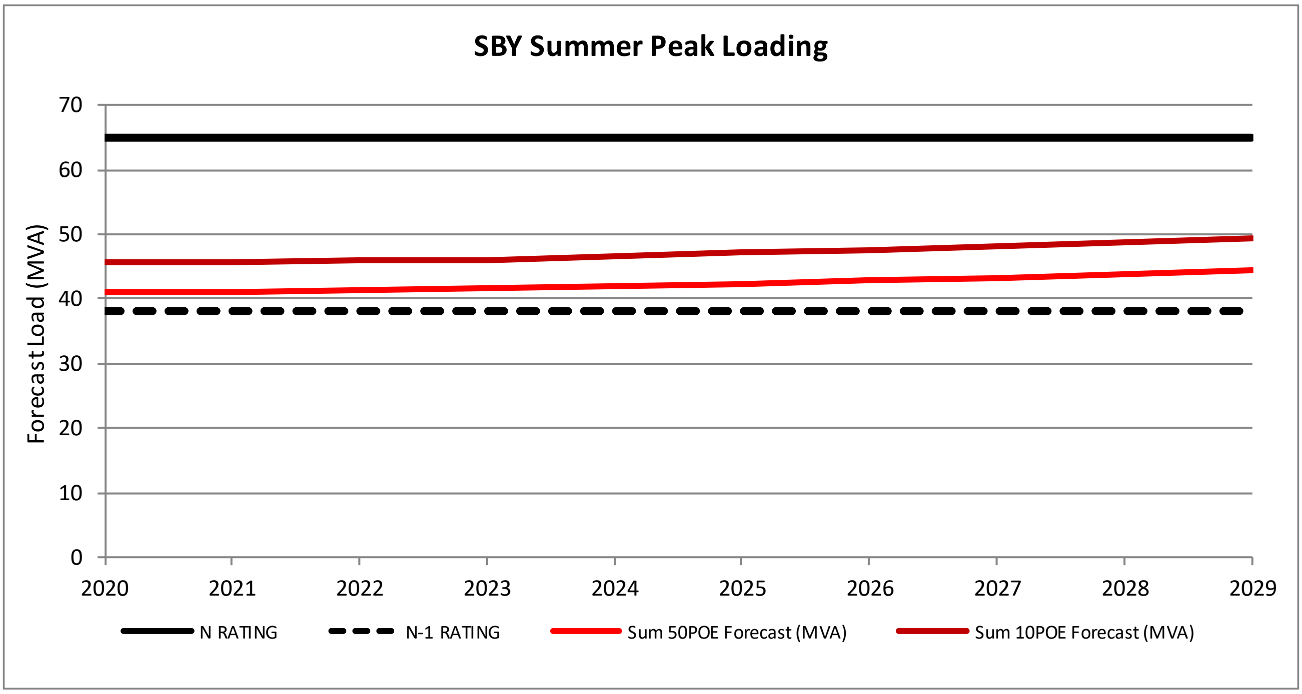

Table 5–83 shows the system normal maximum demand forecast, 95% of which is expected to be reached three hours per year, and the power factor at the time of peak demand. It also shows the forecast N loading, maximum load at risk and hours at risk for system normal conditions, along with the expected unserved energy and the cost of that expected unserved energy. It can be seen that the expected unserved energy is negligible.

Table 5–83: Sunbury Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	45.8	45.7	46.0	45.9	46.5
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	120%	120%	121%	121%	122%
Max load at risk (MVA)	7.8	7.7	8.0	7.9	8.5
Hours at risk (h)	11	12	12	12	13
EUSE (MWh)	0.2	0.2	0.2	0.2	0.2
Cost of EUSE ($ thousand)	6.9	6.9	7.5	7.9	9.3

This substation does not have any large embedded generation connected to it but has up to 7.6 MVA of emergency transfer capacity in 2020, which will continue being used to manage the system normal limitation risk until the augmentation is complete.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the six SBY feeders is forecast to reach 50.5% in 2020, increasing to 52.8% in 2024.

Despite relatively low utilisation forecast on most of the feeder lines, there is insufficient back-up transfer capacity between feeders due to the vast area they supply and their geographical remoteness from one another. Many of the feeder lines are also relatively long and experience excessive voltage drop.

To ensure supply quality and security to our customers, Jemena is proposing to undertake two feeder augmentation projects at SBY within the forward planning period:

- Reconfigure feeder SBY-24 by November 2024, at an estimated cost of $1.4 million. This project involves installing approximately 1 kilometre of underground cable to transfer the load from feeder SBY-24 to feeder SBY-35. Without implementation of this project approximately 5.4 MVA of load reduction will be required under SBY-24 outage conditions.

  An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $94 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

- Establish a tie-line between feeders SBY-23 and SBY-13 by November 2020, at an estimated cost of $1.8 million. This project involves installing approximately 600 meters of underground cable and replacing approximately 5.5 kilometres of overhead conductor. Implementation of this project will provide additional transfer capacity under single contingency conditions to supply the forecast load on SBY-23 and SBY-13. Without implementation of this project approximately 1.5 MVA of load reduction at SBY will be required under outage conditions.

  An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $115 thousand. It is noted however, that this project is driven primarily by reliability considerations (i.e. customer numbers) rather than EUSE, so it is unlikely that there will be a viable non-network solution to defer the augmentation.

5.11.24 SYDENHAM ZONE SUBSTATION (SHM)

Background

Sydenham Zone Substation (SHM) comprises two 66/22 kV 20/33 MVA transformers and two 22 kV buses supplying six 22 kV feeder lines. SHM supplies areas of Sydenham, Hillside and Taylors Lakes.

With some open paddocks and rural areas within its supply area, SHM is at a higher bushfire risk than most of Jemena's supply area. Jemena has installed a REFCL at SHM in 2017[26]. The REFCL is designed to limit short circuit levels that occur during a fault, reducing the likelihood of a fault igniting a bushfire.

Substation limits

Consistent with the ratings listed in Table 5–84, SHM's summer and winter capacities are limited by the 66/22 kV transformer thermal limits.

Table 5–84: Sydenham Zone Substation ratings

	Summer	Winter
Substation N rating	47.6 MVA	47.6 MVA
Substation N-1 rating	38.0 MVA	39.6 MVA

Substation fault levels

Table 5–85 presents SHM's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–85: Sydenham Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	7.1 kA	4.0 kA
LV 22 kV	7.5 kA	1.7 kA

Network impact

The load supplied by the substation under 10% POE and 50% POE summer maximum demand conditions is forecast to exceed the substation's N-1 capacity from 2020. Based on the 10% POE summer maximum demand, outage of a 66/22 kV transformer would result in involuntary load shedding of up to 6.9 MVA in 2020, increasing to 9.9 MVA by 2024.

Figure 5-25 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

[26] 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.

Figure 5-25: Sydenham Zone Substation maximum demand loading

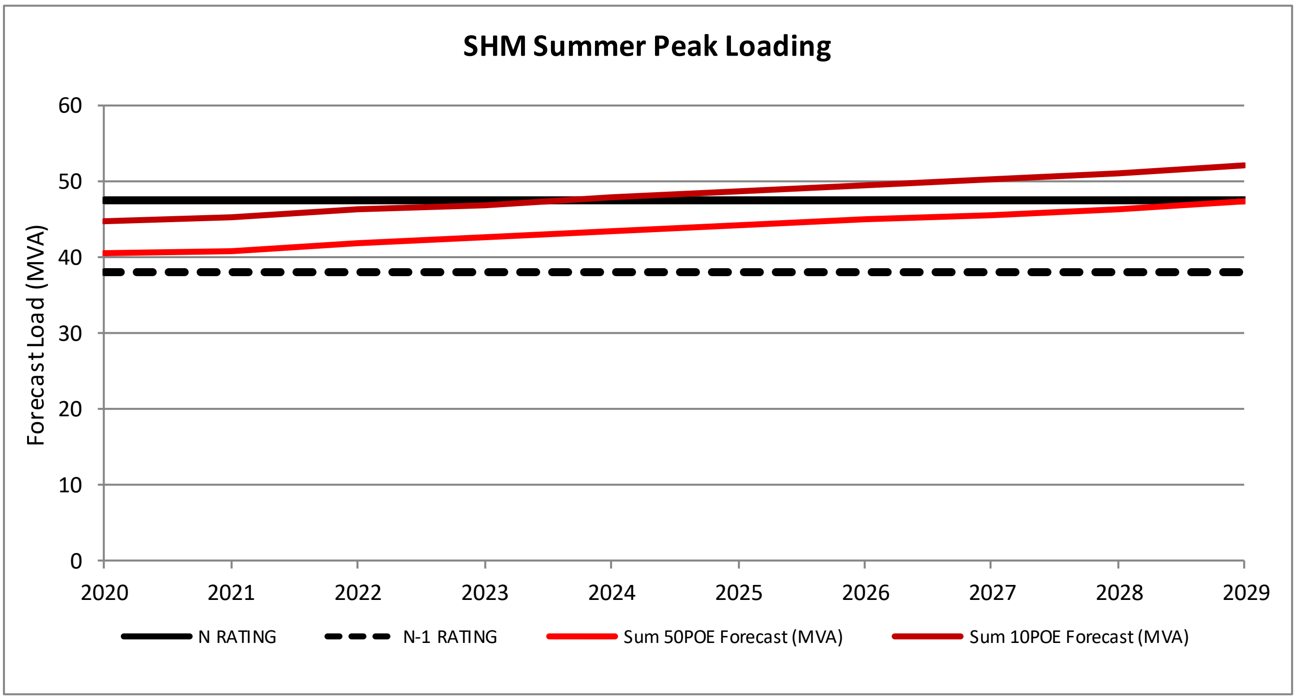

Table 5–86 shows the system normal maximum demand forecast, 95% of which is expected to be reached five hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–86: Sydenham Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	44.9	45.2	46.4	46.9	47.9
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
10% POE N-1 loading (%)	118%	119%	122%	123%	126%
Max load at risk (MVA)	6.9	7.2	8.4	8.9	9.9
Hours at risk (h)	7	7	7	10	11
EUSE (MWh)	0.1	0.1	0.1	0.1	0.3
Cost of EUSE ($ thousand)	3.3	3.7	5.0	5.9	11.1

The table shows that a load reduction of 6.9 MVA in 2020 will defer any forecast limitation by 12 months.

This substation does not have any large embedded generation connected to it but has up to 5.3 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

Four options have been considered for managing the identified network limitation:

- Option 1: Establish a new zone substation in Plumpton (PLN). This option will provide sufficient transformation and distribution capacity to meet anticipated load growth in the Plumpton area, to alleviate the emerging limitations;
- Option 2: Install a new (third) 66/22 kV 20/33 MVA transformer at SHM;
- Option 3: Establish embedded generation suitably located in the SHM supply area; and
- Option 4: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

Jemena has identified that Option 1 maximises the net economic benefits over the life of the assets. Due to its proximity to the high load growth area, a new zone substation in the Plumpton area will reduce high voltage feeder and distribution asset costs, compared to expansion of SHM which was ultimately designed as a two transformer zone substation.

Jemena will continue monitoring the loading on SHM and its feeder lines to identify the optimal timing for establishment of PLN, which is currently estimated at approximately 2026 based on existing demand forecasts.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the six SHM feeders is now forecast to reach 56.2% in 2020, increasing to 62.1% by 2024. With modest utilisation, Jemena is not planning any feeder augmentations at SHM for the forward planning period.

5.11.25 THOMASTOWN ZONE SUBSTATION (TT)

Background

Thomastown Zone Substation (TT) is an AusNet Services owned substation that supplies four 22 kV Jemena feeder lines, TT-03, TT-08, TT-10 and TT-11.

This substation does not have any large embedded generation connected to it and up to 8.4 MVA of emergency transfer capacity in 2020.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the four TT feeders is forecast to reach 72.0% in 2020, decreasing to 71.5% by 2024.

Feeders TT-03 and TT-10, supplying Thomastown and Reservior are forecast to reach 77.0% and 77.2% utilisation respectively in 2024 and does not have sufficient transfer capacity to meet the forecast demand following a network outage. However the optimal economic timing for augmentation is not within this forward planning period.

5.11.26 TOTTENHAM ZONE SUBSTATION (TH)

Background

Tottenham Zone Substation (TH) comprises two 66/22 kV 30/45 MVA transformers and two 22 kV buses supplying six 22 kV feeder lines. TH supplies areas of Tottenham and Brooklyn.

Substation limits

Consistent with the ratings listed in Table 5–87, TH's summer and winter N and N-1 capacities are limited by the transformer 22 kV circuit breaker ratings.

Table 5–87: Tottenham Zone Substation ratings

	Summer	Winter
Substation N rating	47.6 MVA	47.6 MVA
Substation N-1 rating	47.6 MVA	47.6 MVA

Substation fault levels

Table 5–88 presents TH's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–88: Tottenham Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	16.4 kA	13.0 kA
LV 22 kV	9.3 kA	2.0 kA

Network impact

With all transformers in service, and even under N-1 conditions, there is adequate capacity to meet the forecast maximum demand for 10% POE and 50% POE conditions for the forward planning period. Accordingly, no substation capacity augmentation is planned at TH during the forward planning period.

Figure 5-26 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-26: Tottenham Zone Substation maximum demand loading

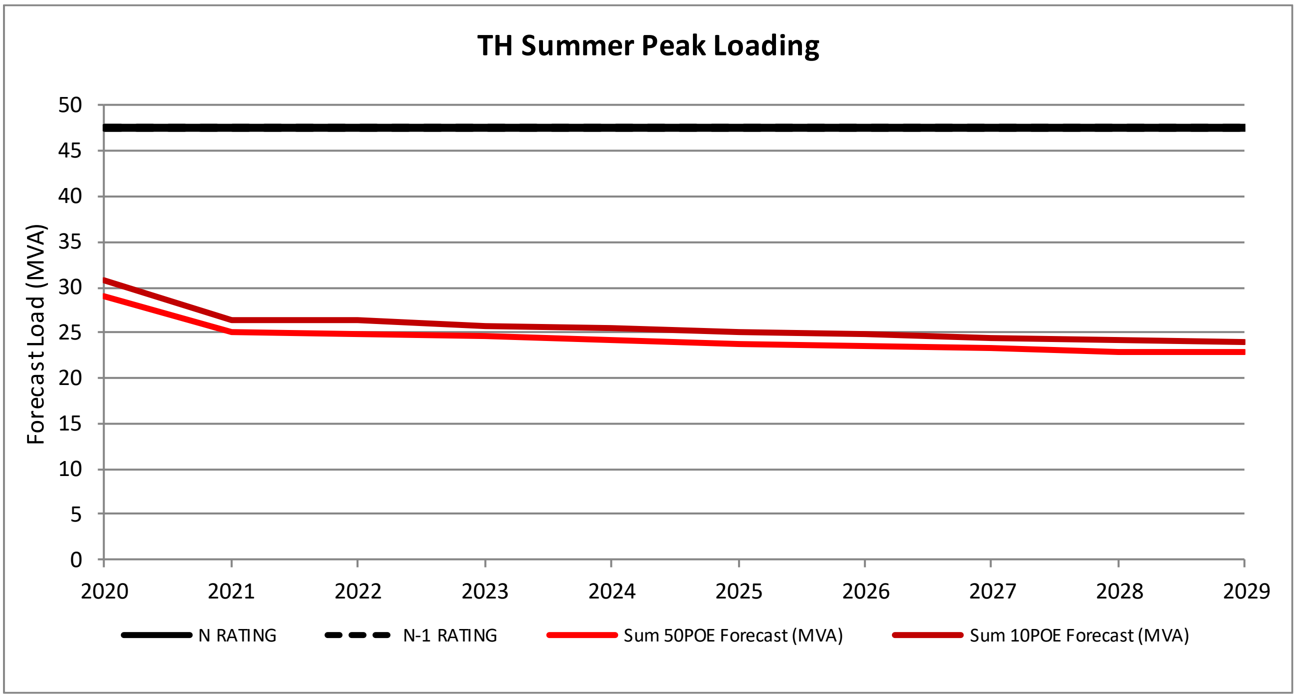

Table 5–89 shows the system normal maximum demand forecast, 95% of which is expected to be reached six hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–89: Tottenham Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	30.8	26.4	26.3	25.8	25.4
Power factor at peak load (p.u)	0.97	0.99	0.99	0.99	0.99
10% POE N-1 loading (%)	65%	55%	55%	54%	53%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

This substation has 3.0 MW of large embedded generation connected to it and up to 17.6 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

There is no forecast load at risk.

Proposed preferred solution

No solutions are required.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average feeder utilisation across the six TH feeders is forecast to reach 50.5% in 2020, decreasing to 43.7% by 2024. Feeder TH-14 is the most heavily loaded with utilisation forecast to reach 114.1% in 2020, decreasing to 104.4% by 2024. No feeder augmentation works are proposed within the forward planning period.

5.11.27 TULLAMARINE ZONE SUBSTATION (TMA)

Background

Tullamarine Zone Substation (TMA) was commissioned in 2015 and comprises two 66/22 kV 20/33 MVA transformers and two 22 kV buses supplying five 22 kV feeder lines. TMA supplies areas of Tullamarine and Keilor Park, including approximately 20 MVA of load previously supplied by Airport West Zone Substation.

TMA will not only supply future growth in Tullamarine and Keilor Park, but also provides support to neighbouring areas of Airport West and Melbourne Airport.

Substation limits

Consistent with the ratings listed in Table 5–90, TMA's summer and winter capacities will be limited by 66/22 kV transformer thermal limits.

Table 5–90: Tullamarine Zone Substation ratings

	Summer	Winter
Substation N rating	49.5 MVA	49.5 MVA
Substation N-1 rating	38.0 MVA	39.6 MVA

Substation fault levels

Table 5–91 presents TMA's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–91: Tullamarine Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	12.8 kA	8.6 kA
LV 22 kV	8.7 kA	1.6 kA

Network impact

There is adequate capacity under N-1 conditions to meet the forecast maximum demand for 10% POE and 50% POE conditions for the forward planning period. Accordingly, no substation capacity augmentation is planned at TMA during the forward planning period.

Figure 5-27 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-27: Tullamarine Zone Substation maximum demand loading

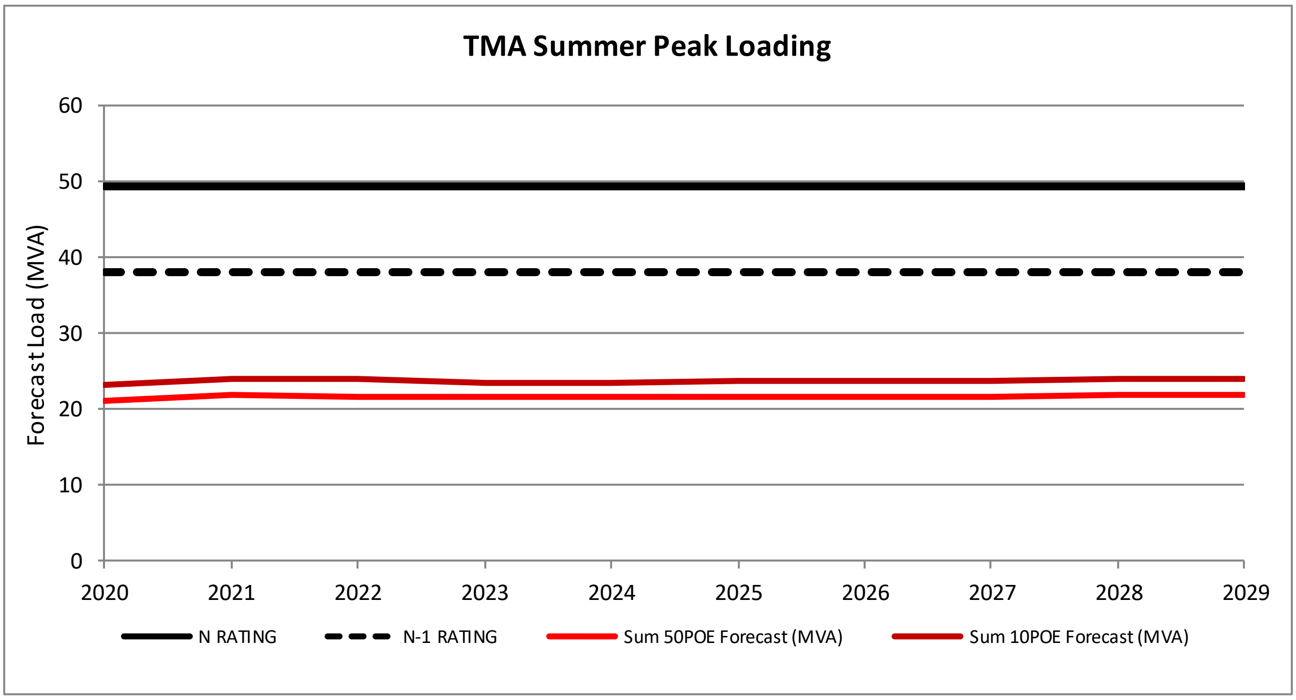

Table 5–92 shows the system normal maximum demand forecast, 95% of which is expected to be reached two hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–92: Tullamarine Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	23.3	24.0	23.9	23.6	23.6
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
10% POE N-1 loading (%)	61%	63%	63%	62%	62%
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

This substation has no large embedded generation connected to it but has up to 8.4 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

There is no forecast load at risk.

Proposed preferred solution

No solutions are required.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the six TMA feeders is forecast to reach 34.9% in 2020. and is forecast to reach 36.2% in 2024. None of these feeders are forecast to reach their capacity within the forward planning period.

Although there is modest utilisation and relatively flat forecast demand for TMA , Jemena is proposing to undertake a network augmentation project -New feeder TMA-15 to manange adjoining AW and BY feeder loading during the forward planning period.

The project New feeder TMA-15 will balance customer numbers and load across feeders TMA-11, TMA-15, AW-08, BY-11 by November 2024, at an estimated cost of $2.3 million. Following new feeder TMA-15, load and customer number will be balanced between adjoing TMA, AW and BY feeders and there will be sufficient transfer capacity under single contingency conditions for feeder TMA-11, AW-08 and BY-11. Without implementation of this option, up to 5.2 MVA of load reduction under a feeder outage condition would be required at AW-08 feeder.

An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $152 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.11.28 WATSONIA ZONE SUBSTATION (WT)

Background

Watsonia Zone Substation (WT) is an AusNet Services owned substation that supplies one 22 kV Jemena feeder line, WT-04. Feeder WT-04 supplies the Watsonia area, including the Simpsons Army Barracks, and has ties with the North Heidelberg Zone Substation (NH).

This substation does not have any embedded generation connected to it and does not have any emergency transfer capacity in 2020.

Zone substation feeder limitations

Feeder WT-04 has a forecast utilisation of 26.7% in 2020, increasing to 30.7% by 2024.

Due to the relatively light loading forecast on WT-04, no feeder augmentation works are proposed within the forward planning period.

5.11.29 YARRAVILLE ZONE SUBSTATION (YVE)

Background

Yarraville Zone Substation (YVE) comprises two 66/22 kV 20/33 MVA transformers and two 22 kV buses supplying nine 22 kV feeder lines. YVE supplies areas of Yarraville, Spotswood and Maribyrnong.

Substation limits

Consistent with the ratings listed in Table 5–93, YVE's summer and winter capacities are limited by the 66/22 kV transformer thermal limits.

Table 5–93: Yarraville Zone Substation ratings

	Summer	Winter
Substation N rating	49.5 MVA	49.5 MVA
Substation N-1 rating	38.0 MVA	39.6 MVA

Substation fault levels

Table 5–94 presents YVE's estimated maximum prospective fault levels at the HV and LV buses.

Table 5–94: Yarraville Zone Substation fault levels

	Three phase	Single phase to ground
HV 66 kV	14.3 kA	12.3 kA
LV 22 kV	9.3 kA	1.6 kA

Network impact

With all transformers in service, there is adequate capacity to meet the forecast maximum demand for 10% POE and 50% POE conditions for the forward planning period. There is adequate capacity to meet the forecast maximum demand under N-1 conditions for 50% POE conditions until 2023. The 10% POE summer maximum demand is forecast to exceed the substation's N-1 capacity from 2021, and an outage of a 66/22 kV transformer would result in involuntary load shedding of up to 1.2 MVA in 2021.

Figure 5-28 shows the 10% POE and 50% POE peak (summer) loading forecast (MVA) compared to the substation limits (MVA).

Figure 5-28: Yarraville Zone Substation maximum demand loading

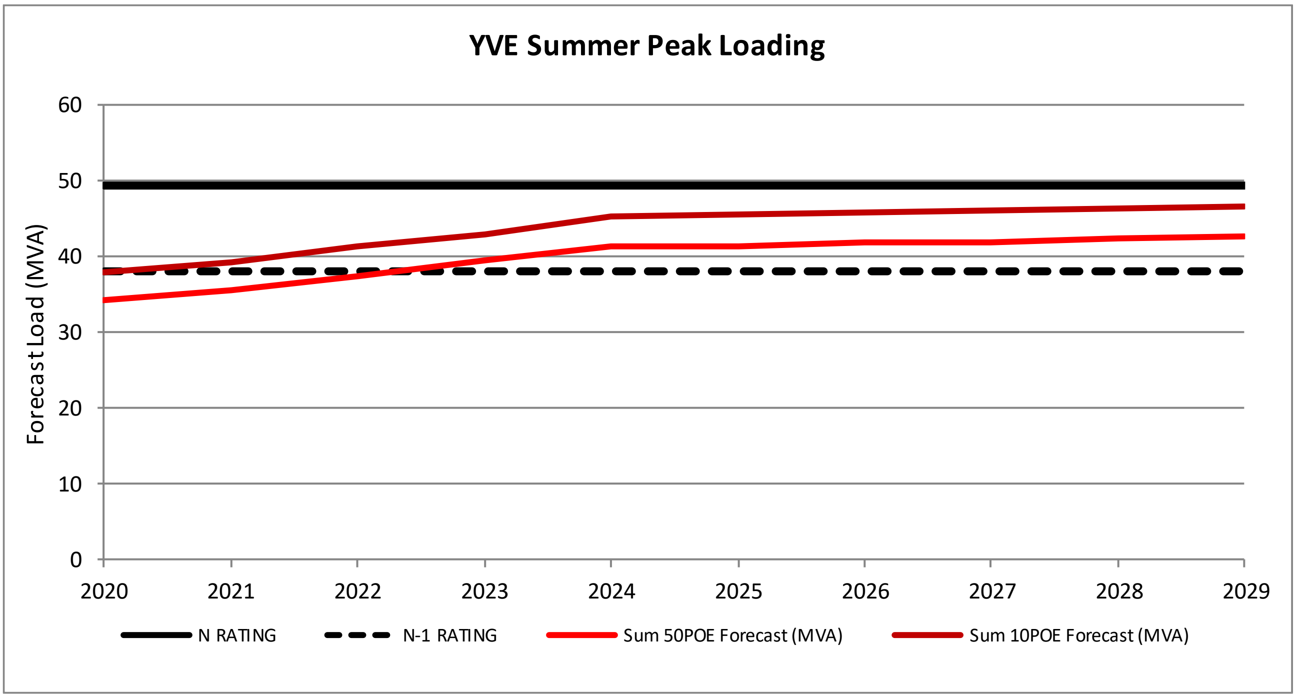

Table 5–95 shows the system normal maximum demand forecast, 95% of which is expected to be reached four hours per year, and the power factor at the time of peak demand. It also shows the forecast N-1 loading, maximum load at risk and hours at risk for a network outage, along with the expected unserved energy and the cost of that expected unserved energy.

Table 5–95: Yarraville Zone Substation loading risk and limitation cost

	2020	2021	2022	2023	2024
10% POE MD (MVA)	37.9	39.2	41.3	43.1	45.2
Power factor at peak load (p.u)	0.96	0.96	0.96	0.96	0.96
10% POE N-1 loading (%)	100%	103%	109%	113%	119%
Max load at risk (MVA)	0.0	1.2	3.3	5.1	7.2
Hours at risk (h)	0	1	2	9	15
EUSE (MWh)	0.0	0.0	0.0	0.0	0.1
Cost of EUSE ($ thousand)	-	0.1	0.6	2.0	5.6

This substation does not have any large embedded generation connected to it but has up to 18.8 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

Despite some existing load at risk, due to the low probability of a transformer outage concurrent with the peak demand period, there is only a small amount of expected unserved energy each year for the forward planning period.

Proposed preferred solution

With moderate load growth over the next five years, there is insufficient risk to economically justify network augmentation on the basis of EUSE.

Zone substation replacements

No significant replacements are required in the forward planning period.

Zone substation feeder limitations

The average summer 10% POE feeder utilisation across the nine YVE feeders is forecast to reach 54.4% in 2020, increasing to 69.1% by 2024.

Feeders YVE-21 and YVE-22 are the heaviest loaded with utilisation forecast to reach 103% and 101% respectively by summer 2021/22.

To ensure supply security to our customers, Jemena is proposing to undertake a feeder augmentation project at YVE within the forward planning period:

- Based on the current forecast the loading on YVE-021 is forecast to go above the feeder rating. A project has been initiated to reconfigure YVE-011 to relieve the loading on YVE-021.The project is estimated to cost $2.6 million and is expected to be completed by summer 2021. Without implementation of this project, up to 1 MVA of load reduction would be required under system normal conditions and 6.5 MVA under single contingency condition; and

- An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $172 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.12 SUB-TRANSMISSION LINE LIMITATIONS

This section presents information about sub-transmission line ratings and forecast loading levels for the forward planning period (2020-2024), and the annualised cost of expected unserved energy for any identified sub-transmission line limitations. Information about potential and proposed risk mitigation options are also presented for sub-transmission line limitations identified in the review process.

This section also includes recently completed projects and network developments that Jemena is committed to deliver within the forward planning period.

Sub-transmission line limitations

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

- The 10% probability of exceedance (POE) peak demand (MVA), being the 10% POE peak loading on the line during the peak loading period (summer or winter) with all loop lines in service;
- System normal loading (%), being the 10% POE peak utilisation of the line with all loop lines in service, presented as a percentage of the line's peak period rating for existing and committed sub-transmission lines;
- Loading with a specified line out of service (OOS) (%), being the 10% POE peak utilisation of the remaining in-service lines presented as a percentage of the lines' peak period ratings;
- Power factor at peak load (p.u), being the power factor at the time of peak demand presented in per unit of real to apparent power demand. The value presented assumes that all capacitor banks connected within the sub-transmission loop are contributing their full reactive power capability;
- Maximum load at risk (MVA), being the load that would be lost if the worst credible outage occurred at the time of 10% POE;
- Hours at risk (h), being the number of hours where the sub-transmission line is forecast to exceed the N-1 rating in a given year and is therefore at risk of not being supplied if the worst credible outage occurs;
- EUSE (MWh), being the expected unserved energy associated with a network outage in a given year and the probability of that network outage actually 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 USE ($ thousand), being the cost of expected unserved energy in a given year (see Section 2.4.2.4 for more information);
- Embedded generation, being the amount of known large (units above 2 MW) embedded generation connected within the sub-transmission 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 sub-transmission lines where a risk of USE is forecast, Jemena 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 6.31% and an asset life of 50 years.

Load transfer capacity

Load transfer capacity is the amount of load that can potentially be transferred to adjacent sub-transmission 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 sub-transmission 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 give an indication of the additional support that can potentially be provided under emergency conditions.

5.12.1 BLTS-FW-BLTS SUB-TRANSMISSION LOOP

Background

The BLTS-FW-BLTS 66 kV sub-transmission loop supplies Footscray West Zone Substation (FW). The transmission supply point for this loop is Brooklyn Terminal Station (BLTS).

Sub-transmission line ratings

Table 5–96: BLTS-FW-BLTS loop ratings

	Summer	Winter
BLTS-FW1 rating	86.3 MVA	86.3 MVA
BLTS-FW2 rating	65.7 MVA	86.3 MVA

Network impact

Table 5–97 shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point.

Table 5–97: BLTS-FW-BLTS loop loading risk and limitation cost

Sub-transmission loop: BLTS-FW	2020	2021	2022	2023	2024
BLTS-FW1					
Summer 10% POE peak demand (MVA)	19.4	20.3	20.2	19.9	19.9
System normal loading (%)	30.3%	31.7%	31.6%	31.1%	31.1%
Loading with BLTS-FW2 OOS (%)	69.8%	73.3%	72.8%	71.6%	71.6%
BLTS-FW2					
Summer 10% POE peak demand (MVA)	25.6	26.8	26.6	26.2	26.2
System normal loading (%)	39.0%	40.8%	40.5%	39.9%	39.9%
Loading with BLTS-FW1 OOS (%)	68.2%	71.4%	70.9%	69.9%	69.7%
BLTS-FW					
Annual hours 95% of peak load expected to be reached	11	11	11	11	11
Power factor at peak load (p.u)	0.90	0.92	0.92	0.91	0.91
Max load at risk (MVA)	0	0	0	0	0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

There are no limitations in the BLTS-FW-BLTS sub-transmission loop in the forecast period.

This sub-transmission loop has no large embedded generation but up to 27.1 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

No risk mitigation is required.

Proposed preferred solution

No solutions are required.

5.12.2 BLTS-NT-YVE-BLTS SUB-TRANSMISSION LOOP

Background

The BLTS-NT-YVE-BLTS 66 kV sub-transmission loop supplies Newport Zone Substation (NT) and Yarraville Zone Substation (YVE). The transmission supply point for this loop is Brooklyn Terminal Station (BLTS).

Sub-transmission line ratings

Table 5–98: BLTS-NT-YVE-BLTS loop ratings

	Summer	Winter
BLTS-NT rating	64.0 MVA	80.0 MVA
BLTS-YVE rating	94.3 MVA	123.5 MVA

Network impact

Table 5–99 shows the system normal and N-1 loading on each line within the sub-transmission loop.

Table 5–99: BLTS-NT-YVE-BLTS loop loading risk and limitation cost

Sub-transmission loop: BLTS-NT-YVE	2020	2021	2022	2023	2024
BLTS-NT					
Summer 10% POE peak demand (MVA)	49.5	50.3	51.8	49.5	50.7
System normal loading (%)	77.3%	78.6%	80.9%	77.3%	79.2%
Loading with BLTS-YVE OOS (%)	157.3%	160.0%	165.0%	156.6%	160.8%
BLTS-YVE					
Summer 10% POE peak demand (MVA)	50.3	51.2	52.8	49.8	51.2
System normal loading (%)	53.3%	54.3%	56.0%	52.8%	54.3%
Loading with BLTS-NT OOS (%)	106.8%	108.6%	112.0%	106.3%	109.0%
BLTS-NT-YVE					
Annual hours 95% of peak load expected to be reached	11	11	11	11	11
Power factor at peak load (p.u)	0.98	0.98	0.98	0.98	0.97
Max load at risk (MVA)	36.7	38.4	41.6	36.2	38.9
Hours at risk (h)	593	670	807	532	647
EUSE (MWh)	324.3	420.5	606.4	275.5	374.1
Cost of EUSE ($ thousand)	13,403.4	17,379.6	25,062.1	11,385.4	15,460.9

The critical limitation for the BLTS-NT-YVE-BLTS sub-transmission loop is the thermal loading on the BLTS-NT line supplied from BLTS, following an outage of the BLTS-YVE line.

A load reduction or network support contracted embedded generation installation of approximately 36.7 MVA in 2020 will defer the forecast limitation to 2021.

This sub-transmission loop has no large embedded generation but up to 16.3 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

The reported USE has increased significantly from the 2017 DAPR as a result of a revision upwards in the forecast demand at both YVE and NT.

Risk mitigation options considered

Three options have been considered for managing the identified network limitation:

- Option 1: Augment the BLTS-NT line. This option involves replacing the flexible conductors at BLTS which currently set the limit for this line;
- Option 2: Establish embedded generation suitably located in the NT supply area; and
- Option 3: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

Jemena has identified Option 1 as the preferred solution. These works have been proposed to Ausnet Services as part of joint network planning arrangements. It is a low cost augmentation so it would not be economic to pursue a non-network solution in this case.

5.12.3 BLTS-TH-BLTS SUB-TRANSMISSION LOOP

Background

The BLTS-TH-BLTS 66 kV sub-transmission loop supplies Tottenham Zone Substation (TH). The transmission supply point for this loop is Brooklyn Terminal Station (BLTS).

Sub-transmission line ratings

Table 5–100: BLTS-TH-BLTS loop ratings

	Summer	Winter
BLTS-TH1 rating	100.6 MVA	125.7 MVA
BLTS-TH2 rating	100.6 MVA	125.7 MVA

Network impact

Table 5–101 shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point.

Table 5–101: BLTS-TH-BLTS loop loading risk and limitation cost

Sub-transmission loop: BLTS-TH	2020	2021	2022	2023	2024
BLTS-TH1					
Summer 10% POE peak demand (MVA)	15.5	13.2	13.2	12.9	12.7
System normal loading (%)	15.4%	13.1%	13.1%	12.8%	12.6%
Loading with BLTS-TH2 OOS (%)	30.8%	26.3%	26.2%	25.6%	25.3%
BLTS-TH2					
Summer 10% POE peak demand (MVA)	15.5	13.2	13.2	12.9	12.7
System normal loading (%)	15.4%	13.1%	13.1%	12.8%	12.6%
Loading with BLTS-TH1 OOS (%)	30.8%	26.3%	26.2%	25.6%	25.3%
BLTS-TH					
Annual hours 95% of peak load expected to be reached	11	11	11	11	11
Power factor at peak load (p.u)	0.96	0.98	0.98	0.99	0.99
Max load at risk (MVA)	0	0	0	0	0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0	0	0	0	0
Cost of EUSE ($ thousand)	0	0	0	0	0

There are no limitations in the BLTS-TH-BLTS sub-transmission loop in the forecast period.

This sub-transmission loop has no large embedded generation but up to 17.6 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

No risk mitigation is required.

Proposed preferred solution

No solutions are required.

5.12.4 BTS-FF-BTS SUB-TRANSMISSION LOOP

Background

The BTS-FF-BTS 22 kV sub-transmission loop supplies Fairfield Zone Substation (FF). The transmission supply point for this loop is Brunswick Terminal Station (BTS).

Sub-transmission line ratings

Table 5–102: BTS-FF-BTS loop ratings

	Summer	Winter
BTS-FF1 rating	11.4 MVA	13.0 MVA
BTS-FF2 rating	13.1 MVA	13.7 MVA
BTS-FF3 rating	13.1 MVA	13.7 MVA

Network impact

Table 5–103 shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point, and presents the overall sub-transmission loop limitation for the forward planning period.

The critical limitation for the BTS-FF-BTS sub-transmission loop is thermal loading on any of the lines supplied from BTS, following an outage of any of the other loop lines, with the most onerous overload on the BTS-FF No.3 line for an outage of the BTS-FF No.2 lines..

This sub-transmission loop has no large embedded generation or emergency transfer capacity available in 2020, which can't be used to reduce the impact of a network outage.

Table 5–103: BTS-FF-BTS loop loading risk and limitation cost

Sub-transmission loop: BTS-FF	2020	2021	2022	2023	2024
BTS-FF1					
Summer 10% POE peak demand (MVA)	6.5	6.6	6.9	7	7.3
System normal loading (%)	57.0%	57.9%	60.5%	61.4%	64.0%
Loading with BTS-FF2 OOS (%)	93.0%	94.7%	98.2%	100.9%	104.4%
Loading with BTS-FF3 OOS (%)	94.7%	96.5%	100.0%	102.6%	106.1%
BTS-FF2					
Summer 10% POE peak demand (MVA)	10.3	10.4	10.8	11.1	11.5
System normal loading (%)	78.6%	79.4%	82.4%	84.7%	87.8%
Loading with BTS-FF1 OOS (%)	103.8%	105.3%	109.2%	112.2%	116.0%
Loading with BTS-FF3 OOS (%)	129.8%	132.1%	136.6%	140.5%	145.0%
BTS-FF3					
Summer 10% POE peak demand (MVA)	10.6	10.7	11.1	11.4	11.8
System normal loading (%)	80.9%	81.7%	84.7%	87.0%	90.1%
Loading with BTS-FF1 OOS (%)	106.1%	107.6%	112.2%	115.3%	119.1%
Loading with BTS-FF2 OOS (%)	131.3%	133.6%	138.2%	142.0%	147.3%
BTS-FF					
Annual hours 95% of peak load expected to be reached	17	17	17	17	17
Power factor at peak load (p.u)	0.98	0.98	0.98	0.97	0.97
Max load at risk (MVA)	7.4	8.0	9.3	10.3	11.8
Hours at risk (h)	39	39	55	52	57
EUSE (MWh)	2.4	2.7	5.3	10.3	19.2
Cost of EUSE ($ thousand)	97.3	110.7	218.9	425.5	795.4

Risk mitigation options considered

Five options have been considered for managing the identified network limitation:

- Option 1: Reinforce supply to FF and surrounding areas from adjacent Heidelberg (HB) substation. This will assist in reducing the load at risk on the BTS-FF lines;
- Option 2: Install a capacitor bank at FF. This option will reduce the load at risk on the BTS-FF lines by reducing network losses and improving the power factor. However this option is unlikely to be practical as the power factor at peak load is already at 0.98;
- Option 3: Augment BTS-FF 22kV loop. This option involves installing a new line from BTS to FF;
- Option 4: Establish embedded generation suitably located within the sub-transmission loop; and
- Option 5: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

Jemena has identified that Option 3, augmenting BTS-FF loop, at an estimated cost of $6.5 million will maximise the net economic benefit. The proposed preferred solution is planned for completion by November 2023 to address the emerging load at risk and to meet the on-going redevelopment at the former APF site.

Option 3 involves establishing a new line from BTS to FF by installing approximately 4.1 kilometres of underground cable.

An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $424 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.12.5 BTS-NS-BTS SUB-TRANSMISSION LOOP

Background

The BTS-NS-BTS 22 kV sub-transmission loop supplies North Essendon Zone Substation (NS). The transmission supply point for this loop is Brunswick Terminal Station (BTS).

Sub-transmission line ratings

Table 5–104: BTS-NS-BTS loop ratings

	Summer	Winter
BTS-NS1 rating	15.2 MVA	15.2 MVA
BTS-NS2 rating	15.2 MVA	15.2 MVA
BTS-NS3 rating	15.2 MVA	15.2 MVA

Network impact

Table 5–105 shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point, and presents the overall sub-transmission loop limitation for the forward planning period.

Table 5–105: BTS-NS-BTS loop loading risk and limitation cost

Sub-transmission loop: BTS-NS	2020	2021	2022	2023	2024
BTS-NS1					
Summer 10% POE peak demand (MVA)	15	15.1	15.5	15.9	16.4
System normal loading (%)	98.7%	99.3%	102.0%	104.6%	107.9%
Loading with BTS-NS2 OOS (%)	156.6%	158.6%	164.5%	169.1%	172.4%
Loading with BTS-NS3 OOS (%)	161.2%	161.8%	169.7%	173.0%	177.6%
BTS-NS2					
Summer 10% POE peak demand (MVA)	14.6	14.7	15.1	15.4	16
System normal loading (%)	96.1%	96.7%	99.3%	101.3%	105.3%
Loading with BTS-NS1 OOS (%)	155.9%	156.6%	164.5%	167.1%	171.7%
Loading with BTS-NS3 OOS (%)	157.2%	157.9%	165.1%	168.4%	173.0%
BTS-NS3					
Summer 10% POE peak demand (MVA)	15	15.2	15.6	15.9	16.5
System normal loading (%)	98.7%	100.0%	102.6%	104.6%	108.6%
Loading with BTS-NS1 OOS (%)	161.2%	161.8%	169.7%	172.4%	177.6%
Loading with BTS-NS2 OOS (%)	157.2%	159.2%	165.1%	169.7%	173.0%
BTS-NS					
Annual hours 95% of peak load expected to be reached	17	17	17	17	17
Power factor at peak load (p.u)	0.91	0.91	0.91	0.91	0.91
Max load at risk (MVA)	23.9	24.2	28.1	29.8	32.2
Hours at risk (h)	61	63	75	77	80
EUSE (MWh)	49.3	56.1	77.4	97.4	121.0
Cost of EUSE ($ thousand)	2,038.7	2,317.3	3,197.7	4,025.0	4,999.1

Risk mitigation options considered

Five options have been considered for managing the identified network limitation:

- Option 1: Reinforce supply to adjacent Essendon Zone Substation (ES), and transfer load from NS to ES. This option includes installation of a new 11 kV feeder from ES and a third transformer at ES. This will assist in reducing the load at risk on the BTS-NS lines;
- Option 2: Install a capacitor bank at NS. This option will reduce the load at risk on the BTS-NS lines by reducing network losses and improving the power factor;
- Option 3: Augment the BTS-NS lines. This option involves replacing sections of the BTS-NS lines with higher rated conductor and underground cable;
- Option 4: Install a new BTS-NS circuit. This option involves installing a new 22 kV underground cable between BTS and NS, and converting the NS 22kV bus to a ring bus arrangement;
- Option 5: Establish embedded generation suitably located within the sub-transmission loop; and

- Option 6: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

Jemena has identified that Option 3, augmenting BTS-NS lines, at an estimated cost of $11.5 million will maximise the net economic benefit. The proposed preferred solution is planned for completion by 2022. This option involves installing approximately 5.1km of new underground cables, thermal uprating 1.25km of existing overhead conductors and installing approximately 5.5km of new overhead conductors.

An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $754 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.12.6 KTS-BY-ES-KTS SUB-TRANSMISSION LOOP

Background

The KTS-BY-ES-KTS 66 kV sub-transmission loop supplies Braybrook Zone Substation (BY) and Essendon Zone Substation (ES). The transmission supply point for this loop is Keilor Terminal Station (KTS).

Sub-transmission line ratings

Table 5–106: KTS-BY-ES-KTS loop ratings

	Summer	Winter
KTS-BY rating	72.6 MVA	83.5 MVA
KTS-ES rating	88 MVA	91.5 MVA

Network impact

Table 5–107 shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point, and presents the overall sub-transmission loop limitation for the forward planning period.

Table 5–107: KTS-BY-ES-KTS loop loading risk and limitation cost

Sub-transmission loop: KTS-BY-ES	2020	2021	2022	2023	2024
KTS-BY					
Summer 10% POE peak demand (MVA)	35.6	35.6	36.4	36.7	37.2
System normal loading (%)	49.0%	49.0%	50.1%	50.6%	51.2%
Loading with KTS-ES OOS (%)	132.9%	132.6%	135.3%	136.1%	137.3%
KTS-ES					
Summer 10% POE peak demand (MVA)	56.8	56.6	57.5	57.7	58.3
System normal loading (%)	68.0%	67.8%	68.9%	69.1%	69.8%
Loading with KTS-BY OOS (%)	112.7%	112.5%	114.6%	115.2%	116.6%
KTS-BY-ES					
Annual hours 95% of peak load expected to be reached	8	8	8	8	8
Power factor at peak load (p.u)	0.92	0.92	0.92	0.92	0.92
Max load at risk (MVA)	23.9	23.7	25.6	26.2	27.1
Hours at risk (h)	56	56	60	60	63
EUSE (MWh)	7.0	6.8	9.3	11.7	13.4
Cost of EUSE ($ thousand)	288.9	279.3	386.2	482.8	554.4

The critical limitation for the KTS-BY-ES-KTS sub-transmission loop is thermal loading of the KTS-BY line, following an outage of the KTS-ES line.

A load reduction or network support contracted embedded generation installation of approximately 23.9 MVA in 2020 will defer the forecast limitation beyond the forward planning period (noting there is no forecast demand growth for this sub-transmission loop).

The sub-transmission loop has no large embedded generation but up to 33.8 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

Four options have been considered for managing the identified network limitation:

- Option 1: Augment the KTS-BY-ES 66kV line, which involves thermal uprate of overhead double circuit sections to design temperature of 100 degree Celcius and maximum temperature rise of 75 degree Celcius;
- Option 2: Install 8 MVAR capacitor banks at BY and/or ES to reduce losses, improve the power factor and thereby offload the loop lines;
- Option 3: Establish embedded generation suitably located within the sub-transmission loop; and
- Option 4: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This would involve the introduction of interruptible loads, as negotiated with customers, by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

Jemena has identified that Option 1, augmenting the KTS-BY-ES 66kV line, at an estimated cost of $966 thousand, will maximise the net economic benefit. The proposed preferred solution is planned for completion by November 2020.

An annual maximum possible payment to non-network service providers to address the risk of EUSE is approximately $63 thousand. A non-network solution providing a lower level of capacity than offered by the preferred network solution would receive a proportionally lower annual payment.

5.12.7 KTS-MAT-AW-PV-KTS SUB-TRANSMISSION LOOP

Background

The KTS-MAT-AW-PV-KTS 66 kV sub-transmission loop supplies the Melbourne Airport Zone Substation (MAT), Airport West Zone Substation (AW), Pascoe Vale Zone Substation (PV), and Tullamarine Zone Substation (TMA). The transmission supply point for this loop is Keilor Terminal Station (KTS).

Melbourne Airport Tullamarine is a major customer on this loop. Its development plans, and industrial customers in the airport precinct, are a primary driver in augmentation plans for the KTS-MAT-AW-PV-KTS 66 kV sub-transmission loop within the forward planning period.

There are two critical thermal loading limitations for the KTS-MAT-AW-PV-KTS sub-transmission loop:

- The KTS-AW line, following an outage of the KTS-TMA line, or KTS-PV line; and
- The KTS-TMA line, following an outage of the KTS-AW line.

Jemena has a committed augmentation project to address the identified thermal capacity constraint for this loop. This project involves splitting of the existing KTS-MAT-AW-PV-KTS sub-transmission loop into a KTS-AW-PV-KTS, and a KTS-TMA-MAT sub-transmission loop by constructing a new KTS-AW 66 kV line, and a new KTS-MAT 66 kV line. The estimated cost of the project is $12.9 million and is due for completion by summer 2020/21.

Sub-transmission line ratings (pre-augmentation)

Table 5–108: KTS-MAT-AW-PV-KTS loop ratings

	Summer	Winter
KTS-TMA rating	101.7 MVA	105.7 MVA
KTS-AW rating	117MVA	126 MVA
KTS-PV rating	101.7 MVA	105.7 MVA

Sub-transmission line ratings (post-augmentation)

	Summer	Winter
KTS-TMA rating	101.7 MVA	105.7 MVA
KTS-AW1 rating	117 MVA	126 MVA
KTS-AW2 rating	117 MVA	126 MVA
KTS-CUST1 rating	117 MVA	126 MVA
KTS-PV rating	101.7 MVA	105.7 MVA

Network impact

Table 5–109 shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point, and presents the overall sub-transmission loop limitation for summer 2019/20.

The KTS-MAT-AW-PV-KTS sub-transmission loop has 8.0 MW of large embedded generation, and up to 17.1 MVA of emergency transfer capacity in 2020, both of which can further reduce the impact of a network outage.

Table 5–109: KTS-MAT-AW-PV-KTS loop loading risk and limitation cost (pre-augmentation)

Sub-transmission loop: KTS-MAT-AW-PV	2020
KTS-TMA	
Summer 10% POE peak demand (MVA)	58.2
System normal loading (%)	57.2%
Loading with KTS-AW OOS (%)	107.3%
Loading with KTS-PV OOS (%)	67.7%
KTS-AW	
Summer 10% POE peak demand (MVA)	85.8
System normal loading (%)	73.3%
Loading with KTS-TMA OOS (%)	113.1%
Loading with KTS-PV OOS (%)	96.8%
KTS-PV	
Summer 10% POE peak demand (MVA)	37.3
System normal loading (%)	37.1%
Loading with KTS-TMA OOS (%)	50.6%
Loading with KTS-AW OOS (%)	75.0%
KTS-MAT-AW-PV	
Annual hours 95% of peak load expected to be reached	8
Power factor at peak load (p.u)	0.99
Max load at risk (MVA)	22.0
Hours at risk (h)	9
EUSE (MWh)	0.0
Cost of EUSE ($ thousand)	0.2

Table 5–110 and Table 5–111 show the system normal and N-1 loading on KTS-AW-PV-KTS, and a KTS-TMA-MAT sub-transmission loop respectively after the augmentation.

Table 5–110: KTS-AW-PV loop loading risk and limitation cost (post-augmentation)

Sub-transmission loop: KTS-AW-PV	2021	2022	2023	2024
KTS-AW1				
Summer 10% POE peak demand (MVA)	48.1	48.1	47.6	47.5
System normal loading (%)	41.1%	41.1%	40.7%	40.6%
Loading with KTS-AW2 OOS (%)	75.7%	75.9%	75.0%	74.9%
Loading with KTS-PV OOS (%)	52.6%	52.6%	51.9%	51.9%
KTS-AW2				
Summer 10% POE peak demand (MVA)	52.6	52.6	52	52
System normal loading (%)	45.0%	45.0%	44.4%	44.4%
Loading with KTS-AW1 OOS (%)	77.3%	77.4%	76.4%	76.3%
Loading with KTS-PV OOS (%)	57.4%	57.4%	56.8%	56.7%
KTS-PV				
Summer 10% POE peak demand (MVA)	27.4	27.4	27	27
System normal loading (%)	27.2%	27.2%	26.8%	26.8%
Loading with KTS-AW1 OOS (%)	40.3%	40.3%	39.7%	39.6%
Loading with KTS-AW2 OOS (%)	38.3%	38.4%	37.8%	37.7%
KTS-AW-PV				
Annual hours 95% of peak load expected to be reached	8	8	8	8
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99
Max load at risk (MVA)	0.0	0.0	0.0	0.0
Hours at risk (h)	0.0	0.0	0.0	0.0
EUSE (MWh)	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0

Table 5–111: KTS-TMA-MAT loop loading risk and limitation cost (post-augmentation)

Sub-transmission loop: KTS-TMA-CUST1	2020	2021	2022	2023	2024
KTS-TMA					
Summer 10% POE peak demand (MVA)	25.3	25.6	25.4	25.0	25.0
System normal loading (%)	24.9%	25.2%	25.0%	24.6%	24.6%
Loading with KTS-CUST1 OOS (%)	50.7%	51.0%	50.7%	49.9%	49.8%
KTS-CUST1					
Summer 10% POE peak demand (MVA)	26.1	26.1	26	25.5	25.5
System normal loading (%)	22.3%	22.3%	22.2%	21.8%	21.8%
Loading with KTS-TMA OOS (%)	44.1%	44.4%	44.1%	43.3%	43.2%
KTS-TMA-CUST1					
Annual hours 95% of peak load expected to be reached	8	8	8	8	8
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
Max load at risk (MVA)	0.0	0.0	0.0	0.0	0.0
Hours at risk (h)	0.0	0.0	0.0	0.0	0.0
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($ thousand)	0.0	0.0	0.0	0.0	0.0

Risk mitigation options considered

No risk mitigation is required.

Proposed preferred solution

No solutions are required.

5.12.8 KTS -SBY-SHM-KTS SUB-TRANSMISSION LOOP

Background

The KTS-SBY (WND-GSB)-SHM-KTS 66 kV sub-transmission loop supplies Jemena's Sunbury Zone Substation (SBY) and Sydenham Zone Substation (SHM), and Powercor's Gisborne (GSB), and Woodend (WND) Zone Substations. Its transmission supply point is Keilor Terminal Station (KTS).

As part of western metropolitan Melbourne transmission connection and sub-transmission capacity project;

- Powercor transferred the supply of their Melton Zone Substation (MLN) to DPTS, which was previously supplied from the KTS- MLN-SBY-(WND-GSB)-SHM-KTS sub-transmission loop; and
- Jemena commissioned a new 66kV line in May 2018 by purchasing sections of the KTS-MLN-SBY 66 kV line from Powercor and installed new 66kV line sections to form a new No.2 KTS-SBY 66 kV line to continue supplying SBY, WND, GSB and SHM.

Sub-transmission line ratings

Table 5–112: KTS-SBY (WND-GSB)-SHM-KTS loop ratings

	Summer	Winter
KTS-SBY1 rating	96.0 MVA	116.6 MVA
KTS-SBY2 rating	94.3 MVA	100.6 MVA
KTS-SHM rating	117.2 MVA	128.0 MVA

Network impact

Table 5–113 shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point, and presents the overall sub-transmission loop limitation for the forward planning period.

The results shows that the critical limitation for the KTS-SBY (WND-GSB)-SHM-KTS sub-transmission loop is on the KTS-SBY No.2 line, following an outage of the KTS-SBY No.1 line.

A load reduction or network support contracted embedded generation installation of approximately 11.1 MVA in 2020 would defer the forecast limitation to 2021.

This sub-transmission loop has no large embedded generation or emergency transfer capacity in 2020, which can be utilised to reduce the network limitation.

Table 5–113: KTS-SBY (WND-GSB)-SHM-KTS loop loading risk and limitation cost

Sub-transmission loop: KTS-SBY (WND-GSB)-SHM	2020	2021	2022	2023	2024
KTS-SBY1					
Summer 10% POE peak demand (MVA)	51.8	52.5	53.6	54.1	54.5
System normal loading (%)	54.0%	54.7%	55.8%	56.4%	56.8%
Loading with KTS-SBY2 oos (%)	104.1%	104.4%	107.1%	108.4%	109.9%
Loading with KTS-SHM oos (%)	76.4%	77.3%	79.0%	79.6%	80.3%
KTS-SBY2					
Summer 10% POE peak demand (MVA)	70	70.7	72.4	73.1	74
System normal loading (%)	74.2%	75.0%	76.8%	77.5%	78.5%
Loading with KTS-SHM oos (%)	94.5%	95.5%	97.7%	98.6%	99.9%
Loading with KTS-SBY1 oos (%)	107.1%	108.3%	110.7%	112.1%	113.4%
KTS-SHM					
Summer 10% POE peak demand (MVA)	36.9	37.4	38.1	38.5	38.8
System normal loading (%)	31.5%	32.0%	32.6%	32.9%	33.2%
Loading with KTS-SBY2 oos (%)	60.9%	61.0%	62.6%	63.4%	64.3%
Loading with KTS-SBY1 oos (%)	52.8%	53.4%	54.5%	55.1%	55.6%
KTS-SBY (WND-GSB)-SHM					
Annual hours 95% of peak load expected to be reached	9	9	9	9	9
Power factor at peak load (p.u)	0.96	0.96	0.96	0.96	0.96
Max load at risk (MVA)	11.1	13.0	16.9	19.2	21.3
Hours at risk (h)	1	1	3	5	5
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($k)	0.0	0.0	0.1	0.3	0.4

Risk mitigation options considered

Despite existing load at risk, due to the low probability of a line outage concurrent with the peak demand period, there is only a small amount of expected unserved energy each year. There is insufficient risk to economically justify any of the risk mitigation options.

Jemena will manage the existing risk without further network augmentation at this time, and will continue to monitor and report any supply risks in future DAPR’s.

Proposed preferred solution

No solutions are required.

5.12.9 SMTS-SSS-ST-SMTS SUB-TRANSMISSION LOOP

Background

The SMTS-SSS-ST-SMTS 66 kV sub-transmission loop supplies Somerton Zone Substation (ST) and the Somerton Switching Station (SSS), to which the AGL owned Somerton Power Station (SPS) is connected. Somerton Power Station is a gas powered peaking generator with a nameplate capacity of 150 MW. The transmission supply point for this loop is South Morang Terminal Station (SMTS).

Sub-transmission line ratings

Table 5–114: SMTS-SSS-ST-SMTS loop ratings

	Summer	Winter
SMTS-SSS rating	117.2 MVA	121.7 MVA
SMTS-ST rating	117.2 MVA	126.3 MVA

Network impact

Table 5–115, shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point.

Table 5–115: SMTS-SSS-ST-SMTS loop loading risk and limitation cost

Sub-transmission loop: SMTS-SSS-ST	2020	2021	2022	2023	2024
SMTS-SSS					
Summer 10% POE peak demand (MVA)	32.1	32.8	33.3	33.3	33.8
System normal loading (%)	27.4%	28.0%	28.4%	28.4%	28.8%
Loading with SMTS-ST OOS (%)	74.1%	75.4%	76.7%	76.9%	77.8%
SMTS-ST					
Summer 10% POE peak demand (MVA)	50.9	51.9	52.7	52.8	53.5
System normal loading (%)	43.4%	44.3%	45.0%	45.1%	45.6%
Loading with SMTS-SSS OOS (%)	72.0%	73.3%	74.7%	74.8%	75.7%
SMTS-SSS-ST					
Annual hours 95% of peak load expected to be reached	14	14	14	14	14
Power factor at peak load (p.u)	0.96	0.96	0.96	0.96	0.96
Max load at risk (MVA)	0	0	0	0	0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0	0	0	0	0
Cost of EUSE ($k)	0	0	0	0	0

There are no limitations in the SMTS-SSS-ST-SMTS sub-transmission loop in the forecast period.

This sub-transmission loop has 150 MW of large embedded generation, and up to 15.6 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

No risk mitigation is required.

Proposed preferred solution

No solutions are required.

5.12.10 TSTS-HB-L-Q-TSTS SUB-TRANSMISSION LOOP

Background

The TSTS-HB-L-Q-TSTS 66 kV sub-transmission loop supplies Jemena's Heidelberg Zone Substation (HB), and Citipower's Deepdene (L) and Kew (Q) zone substations. Its transmission supply point is Templestowe Terminal Station (TSTS).

Sub-transmission line ratings

Table 5–116: TSTS-HB-L-Q-TSTS loop ratings

	Summer	Winter
TSTS-HB rating	117.2 MVA	126.3 MVA
TSTS-L rating	106.9 MVA	108.6 MVA

Network impact

Table 5–117, shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point.

Table 5–117: TSTS-HB-L-Q-TSTS loop loading risk and limitation cost

Sub-transmission loop: TSTS-HB-L-Q	2020	2021	2022	2023	2024
TSTS-HB					
Summer 10% POE peak demand (MVA)	64.2	68.6	69.8	70.5	70.1
System normal loading (%)	54.8%	58.5%	59.5%	60.1%	59.8%
Loading with TSTS-L OOS (%)	103.4%	110.3%	112.3%	113.8%	113.2%
TSTS-L					
Summer 10% POE peak demand (MVA)	51.7	55.2	56.2	56.9	56.6
System normal loading (%)	48.4%	51.6%	52.6%	53.3%	53.0%
Loading with TSTS-HB OOS (%)	116.5%	124.3%	126.6%	128.4%	127.7%
TSTS-HB-Q-L					
Annual hours 95% of peak load expected to be reached	17	17	17	17	17
Power factor at peak load (p.u)	0.95	0.95	0.95	0.95	0.95
Max load at risk (MVA)	17.6	25.9	28.4	30.3	29.6
Hours at risk (h)	32	60	62	66	62
EUSE (MWh)	0.1	0.2	9.5	15.5	13.0
Cost of EUSE ($k)	3.2	8.1	392.7	639.1	538.6

The critical limitations for the TSTS-HB-L-Q-TSTS sub-transmission loop are loading combination of:

- Thermal loading on the remaining in-service lines supplied from TSTS, following an outage of either the TSTS-HB, or TSTS-L lines supplied from TSTS, with the overload most onerous on the TSTS-L line for an outage of the TSTS-HB line; and
- Voltage collapse of the entire loop may occur following an outage of either the TSTS-HB, or TSTS-L lines.

A load reduction or network support contracted embedded generation installation of approximately 18 MVA in 2020 would defer the forecast limitation to beyond the forward planning period.

This sub-transmission loop does not have any large embedded generation or emergency transfer capacity.

Risk mitigation options considered

Four options have been considered for managing the identified network limitation:

- Option 1: Augmentation of the TSTS-HB 66 kV line;
- Option 2: Installation of a new 8 MVAR capacitor bank to provide the required reactive support to mitigate the power factor limitation;
- Option 3: Establish embedded generation suitably located in the HB supply area, with sufficient reactive support to mitigate the power factor limitation; and.
- Option 4: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

Jemena will undertake joint planning with CitiPower to identify the constraint solution which maximises the net economic benefits to customers.

5.12.11 TTS-BD-BMS-VCO-COO-TTS SUB-TRANSMISSION LOOP

Background

The TTS-BD-BMS-COO-TTS 66 kV sub-transmission loop supplies Broadmeadows Zone Substation (BD), Broadmeadows South Zone Substation (BMS), Coolaroo Zone Substation (COO) and the customer owned Visy-Paper Zone Substation (VCO). The transmission supply point for this loop is Thomastown Terminal Station (TTS).

Sub-transmission line ratings

Table 5–118: TTS-BD-BMS-VCO-COO-TTS loop ratings

	Summer	Winter
TTS-BMS rating	101.7 MVA	105.7 MVA
TTS-BD rating	117.2 MVA	126.3 MVA
TTS-COO rating	101.7 MVA	109.2 MVA

Network impact

Table 5–119, shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point, and presents the overall sub-transmission loop limitation for the forward planning period.

The critical limitation for the TTS-BD-BMS-VCO-COO-TTS sub-transmission loop is thermal loading of the TTS-COO line, following outage of the TTS-BD line.

A load reduction or network support contracted embedded generation installation of approximately 13 MVA in 2020 would defer the forecast limitation until 2021.

This sub-transmission loop has 10.5 MW of large embedded generation and up to 26.4 MVA of emergency transfer capacity in 2020, both of which can further reduce the impact of a network outage.

Table 5–119: TTS-BD-BMS-VCO-COO-TTS loop loading risk and limitation cost

Sub-transmission loop: TTS-BD-BMS-VCO-COO	2020	2021	2022	2023	2024
TTS-BMS (TTS-BD1)					
Summer 10% POE peak demand (MVA)	62.9	62.5	62.7	62	62.2
System normal loading (%)	61.8%	61.5%	61.7%	61.0%	61.2%
Loading with TTS-BD OOS (%)	101.2%	100.1%	100.7%	99.7%	99.8%
Loading with TTS-COO OOS (%)	95.4%	94.5%	95.4%	94.3%	94.6%
TTS-BD (TTS-BD2)					
Summer 10% POE peak demand (MVA)	71.1	70.6	70.8	70.2	70.3
System normal loading (%)	60.7%	60.2%	60.4%	59.9%	60.0%
Loading with TTS-BMS OOS (%)	94.0%	93.1%	93.7%	92.7%	93.0%
Loading with TTS-COO OOS (%)	97.4%	96.5%	97.4%	96.4%	96.8%
TTS-COO					
Summer 10% POE peak demand (MVA)	71.9	71.7	72	71.6	72
System normal loading (%)	70.7%	70.5%	70.8%	70.4%	70.8%
Loading with TTS-BMS OOS (%)	98.2%	97.5%	98.3%	97.5%	98.0%
Loading with TTS-BD OOS (%)	106.4%	105.6%	106.4%	105.5%	105.9%
TTS-BD-BMS-VCO-COO					
Annual hours 95% of peak load expected to be reached	17	17	17	17	17
Power factor at peak load (p.u)	0.94	0.94	0.94	0.94	0.94
Max load at risk (MVA)	13.1	11.4	13.0	11.2	12.0
Hours at risk (h)	6	7	5	4	5
EUSE (MWh)	0.0	0.0	0.0	0.0	0.0
Cost of EUSE ($k)	0.1	0.1	0.1	0.1	0.1

Risk mitigation options considered

Three options have been considered for managing the identified network limitation:

- Option 1: Augment the TTS-BMS and TTS-COO lines, which involve replacing the smaller sized conductor sections of this line with 37/3.75 mm AAC conductor;
- Option 2: Establish embedded generation suitably located within the sub-transmission loop; and
- Option 3: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

Despite existing load at risk, due to the low probability of a line outage concurrent with the peak demand period, there is only a small amount of expected unserved energy each year. With the forecast demand growth being relatively flat over the forward planning period for this loop, there is insufficient risk to economically justify any of the risk mitigation options identified.

Jemena will manage the existing risk without further network augmentation at this time, and will continue to monitor and report any BD, BMS and COO supply risks in future DAPR's.

5.12.12 TTS-CN-CS-TTS SUB-TRANSMISSION LOOP

Background

The TTS-CN-CS-TTS 66 kV sub-transmission loop supplies Coburg North Zone Substation (CN) and Coburg South Zone Substation (CS). The transmission supply point for this loop is Thomastown Terminal Station (TTS).

Sub-transmission line ratings

Table 5–120: TTS-CN-CS-TTS loop ratings

	Summer	Winter
TTS-CN rating	117.2 MVA	126.3 MVA
TTS-CS rating	117.2 MVA	126.3 MVA

Network impact

With the proposed load transfer from CS to PTN Zone Substation as part of the committed Preston Conversion Stage 6 project which is scheduled to be completed in 2020, from summer 2021, there is adequate capacity to meet the anticipated maximum demand for under 10% POE conditions for the forward planning period under system normal and N-1 conditions.

Table **5**–**121**, shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point, and presents the overall sub-transmission loop limitation for the forward planning period.

Table 5–121**: TTS-CN-CS-TTS loop loading risk and limitation cost**

Sub-transmission loop: TTS-CN-CS	2020	2021	2022	2023	2024
TTS-CN					
Summer 10% POE peak demand (MVA)	75.7	62.7	63.8	64	64.5
System normal loading (%)	64.6%	53.5%	54.4%	54.6%	55.0%
Loading with TTS-CS OOS (%)	105.4%	86.9%	88.7%	89.2%	90.1%
TTS-CS					
Summer 10% POE peak demand (MVA)	46.3	38.3	39.3	39.6	40.2
System normal loading (%)	39.5%	32.7%	33.5%	33.8%	34.3%
Loading with TTS-CN OOS (%)	107.9%	88.3%	90.2%	90.7%	91.6%
TTS-CN-CS					
Annual hours 95% of peak load expected to be reached	17	17	17	17	17
Power factor at peak load (p.u)	0.99	1.00	1.00	1.00	1.00
Max load at risk (MVA)	9.3	0	0	0	0
Hours at risk (h)	9	0	0	0	0
EUSE (MWh)	0	0	0	0	0
Cost of EUSE ($k)	0.2	0	0	0	0

The critical limitation for the TTS-CN-CS-TTS sub-transmission loop is thermal loading of:

- The TTS-CN line, following an outage of the TTS-CS line; and
- The TTS-CS line, following an outage of the TTS-CN line.

This sub-transmission loop has 2.0 MW of large embedded generation and up to 12.6 MVA of emergency transfer capacity in 2020, both of which can further reduce the impact of a network outage.

Risk mitigation options considered

The load at risk under N-1 condition for summer 2019/20 will manged by using the available emergency load transfer capability.

Proposed preferred solution

No solutions are required in the forward planning period.

5.12.13 TTS-EPN-EP-TTS SUB-TRANSMISSION LOOP

Background

The TTS-EP-EPN-TTS 66 kV sub-transmission loop supplies the East Preston Zone Substations (EP and EPN). This loop previously supplied Preston 66/6.6 kV Zone Substation (P) which was decommissioned in November 2017. P will be replaced with new Preson 66/22 kV zone substation (PTN) in 2020 when the committed P Conversion Stage 6 project is scheduled to be completed. Once this project is completed, this will form the TTS-PTN-EP-EPN-TTS 66kV loop. The transmission supply point for this loop is Thomastown Terminal Station (TTS).

Sub-transmission line ratings

Table 5–122: TTS-EPN-EP-TTS loop ratings

	Summer	Winter
TTS-EP rating	78.9 MVA	93.2 MVA
TTS-EPN rating	65.2 MVA	86.9 MVA

Network impact

Table 5–123, shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point, and presents the overall sub-transmission loop limitation for the forward planning period.

Table 5–123: TTS-(PTN) EPN-EP-TTS loop loading risk and limitation cost

Sub-transmission loop: TTS-EP-EPN-TTS	2020	2021	2022	2023	2024
TTS-EPN					
Summer 10% POE peak demand (MVA)	25.4	43.1	43	42.4	42.3
System normal loading (%)	39.0%	66.1%	66.0%	65.0%	64.9%
Loading with TTS-EP OOS (%)	77.5%	106.7%	106.6%	105.1%	104.8%
TTS-EP					
Summer 10% POE peak demand (MVA)	25.5	26	26	25.7	25.7
System normal loading (%)	32.3%	33.0%	33.0%	32.6%	32.6%
Loading with TTS-EPN OOS (%)	63.1%	88.8%	88.7%	87.5%	87.2%
TTS-EP-EPN					
Annual hours 95% of peak load expected to be reached	12	12	12	12	12
Power factor at peak load (p.u)	1.0	0.99	0.99	0.99	0.99
Max load at risk (MVA)	0	4.4	4.3	3.3	3.1
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0	0	0	0	0
Cost of EUSE ($k)	0	0	0	0	0

There are no limitations in the TTS-EPN-EP-TTS sub-transmission loop for summer 2019/20. Once PTN forms part of this loop in 2020, there is only minor limitations on this loop in the forecast period which can be managed via emergency transfers.

This sub-transmission loop has no large embedded generation but up to 7.2 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

The load at risk under N-1 condition will manged by using the available emergency load transfer capability.

Proposed preferred solution

No solutions are required.

5.12.14 TTS-NEI-NH-WT-TTS SUB-TRANSMISSION LOOP

Background

The TTS-NEI-NH-WT-TTS 66 kV sub-transmission loop supplies Jemena's North Heidelberg Zone Substation (NH), AusNet Services' Watsonia Zone Substation (WT), and the Nilsen Electrical Industries customer substation (NEI). The transmission supply point for this loop is Thomastown Terminal Station (TTS).

Sub-transmission line ratings

Table 5–124: TTS-NEI-NH-WT-TTS loop ratings

	Summer	Winter
TTS-NH rating	117.2 MVA	126.3 MVA
TTS-WT rating	117.2 MVA	126.3 MVA

Network impact

Table 5–125, shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point, and presents the overall sub-transmission loop limitation for the forward planning period.

Table 5–125: TTS-NEI-NH-WT-TTS loop loading risk and limitation cost

Sub-transmission loop: TTS-NEI-NH-WT	2020	2021	2022	2023	2024
TTS-NH					
Summer 10% POE peak demand (MVA)	87.7	87.9	88.4	88	88.4
System normal loading (%)	74.8%	75.0%	75.4%	75.1%	75.4%
Loading with TTS-WT OOS (%)	124.7%	125.2%	126.0%	125.8%	126.5%
TTS-WT					
Summer 10% POE peak demand (MVA)	56.2	56.5	56.9	57	57.3
System normal loading (%)	48.0%	48.2%	48.5%	48.6%	48.9%
Loading with TTS-NEI OOS (%)	124.6%	125.2%	125.9%	125.8%	126.4%
TTS-NEI-NH-WT					
Annual hours 95% of peak load expected to be reached	12	12	12	12	12
Power factor at peak load (p.u)	0.99	0.99	0.99	0.99	0.99
Max load at risk (MVA)	28.9	29.5	30.5	30.2	31.1
Hours at risk (h)	51	58	57	57	58
EUSE (MWh)	1.6	2.6	4.0	3.3	4.7
Cost of EUSE ($k)	64.3	108.4	166.3	135.0	193.6

The critical limitation for the TTS-NEI-NH-WT-TTS sub-transmission loop is thermal loading of:

- The TTS-NH line, following an outage of the TTS-WT line; and
- The TTS-WT line, following an outage of the TTS-NH line.

A load reduction or network support contracted embedded generation installation of approximately 19 MVA in 2020 would defer the forecast limitation for the forecast period.

This sub-transmission loop has no large embedded generation but up to 9.5 MVA of emergency transfer capacity in 2020, which can further reduce the impact of a network outage.

Risk mitigation options considered

Four options have been considered for managing the identified limitations:

- Option 1: Improved load transfer capability away from NH as part of the Preston Conversion Program;
- Option 2: Establish a third 66 kV line to NH or WT to alleviate the existing line loading limitation;
- Option 3: Establish embedded generation suitably located in the NH supply area, with sufficient reactive support to mitigate the power factor limitation; and
- Option 4: Introduce demand management to voluntarily reduce demand at peak demand times and during network outages. This involves introducing interruptible loads (as negotiated with customers) by offering incentives in the form of reduced electricity charges or outage rebates.

Proposed preferred solution

With the proposed remaining works for the Preston Conversion Program (under Option 1), it is expected the amount load transfer capability from NH to EPN will improve, which would enable the forecast load at risk to be managed without further network augmentation for the forward planning period. However Jemena will continue to monitor and report any supply risks in future DAPRs.

5.12.15 WMTS-FE-WMTS SUB-TRANSMISSION LOOP

Background

The WMTS-FE-WMTS 66 kV sub-transmission loop supplies Footscray East Zone Substation (FE). The transmission supply point for this loop is West Melbourne Terminal Station (WMTS).

Sub-transmission line ratings

Table 5–126: WMTS-FE-WMTS loop ratings

	Summer	Winter
WMTS-FE1 rating	84.6 MVA	91.5 MVA
WMTS-FE2 rating	83.5 MVA	91.5 MVA

Network impact

Table 5–127, shows the system normal and N-1 loading on each line within the sub-transmission loop connected to the transmission supply point, and presents the overall sub-transmission loop limitation for the forward planning period.

Table 5–127: WMTS-FE-WMTS loop loading risk and limitation cost

Sub-transmission loop: WMTS-FE	2020	2021	2022	2023	2024
WMTS-FE1					
Summer 10% POE peak demand (MVA)	23.3	23.6	24.3	22.6	23.4
System normal loading (%)	27.5%	27.9%	28.7%	26.7%	27.7%
Loading with WMTS-FE2 OOS (%)	62.5%	63.2%	65.1%	58.4%	60.4%
WMTS-FE2					
Summer 10% POE peak demand (MVA)	29.4	29.7	30.6	26.6	27.5
System normal loading (%)	35.2%	35.6%	36.6%	31.9%	32.9%
Loading with WMTS-FE1 OOS (%)	63.4%	64.0%	65.9%	59.0%	61.2%
WMTS-FE					
Annual hours 95% of peak load expected to be reached	19	19	19	19	19
Power factor at peak load (p.u)	1.0	1.0	1.0	1.0	1.0
Max load at risk (MVA)	0	0	0	0	0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0	0	0	0	0
Cost of EUSE ($k)	0	0	0	0	0

There are no limitations in the WMTS-FE-WMTS sub-transmission loop in the forecast period.

This sub-transmission loop has no large embedded generation but up to 22.9 MVA of emergency transfer capacity in 2020.

Risk mitigation options considered

No risk mitigation is required.

Proposed preferred solution

No solutions are required.

5.12.16 WMTS-FT-WMTS SUB-TRANSMISSION LOOP

Background

The WMTS-FT-WMTS 66 kV sub-transmission loop supplies Flemington Zone Substation (FT). The transmission supply point for this loop is West Melbourne Terminal Station (WMTS).

Sub-transmission line ratings

Table 5–128: WMTS-FT-WMTS loop ratings

	Summer	Winter
WMTS-FT1 rating	52.0 MVA	64.0 MVA
WMTS-FT2 rating	65.2 MVA	76.6 MVA

Network impact

Table 5–129, shows the system normal and N-1 loading on each line within the sub-transmission loop, and presents the overall sub-transmission loop limitation for the forward planning period.

Table 5–129: WMTS-FT-WMTS loop loading risk and limitation cost

Sub-transmission loop: WMTS-FT	2020	2021	2022	2023	2024
WMTS-FT1					
Summer 10% POE peak demand (MVA)	18.2	18.1	18.3	18.4	18.8
System normal loading (%)	35.0%	34.8%	35.2%	35.4%	36.2%
Loading with WMTS-FT2 OOS (%)	71.2%	70.6%	71.5%	71.9%	73.8%
WMTS-FT2					
Summer 10% POE peak demand (MVA)	18.2	18.1	18.3	18.4	18.8
System normal loading (%)	27.9%	27.8%	28.1%	28.2%	28.8%
Loading with WMTS-FT1 OOS (%)	56.7%	56.4%	57.2%	57.5%	58.9%
WMTS-FT					
Annual hours 95% of peak load expected to be reached	19	19	19	19	19
Power factor at peak load (p.u)	1.00	1.00	1.00	1.00	1.00
Max load at risk (MVA)	0	0	0	0	0
Hours at risk (h)	0	0	0	0	0
EUSE (MWh)	0	0	0	0	0
Cost of EUSE ($k)	0	0	0	0	0

There are no limitations in the WMTS-FT-WMTS sub-transmission loop in the forecast period.

This sub-transmission loop has no large embedded generation and only 0.9 MVA of emergency transfer capacity in 2019.

Risk mitigation options considered

No risk mitigation is required.

Proposed preferred solution

No solutions are required.

Appendix A
Feeder Line Loadings

Table A–1: Feeders forecast to reach or exceed 100% utilisation by summer 2024/25 (10% POE forecast)

Feeder	Season	10% POE Demand Forecast					
		2020	2021	2022	2023	2024	2025
AW01	Summer	96%	96%	100%	103%	105%	108%
	Winter	74%	74%	76%	79%	80%	81%
AW06	Summer	129%	128%	130%	129%	128%	128%
	Winter	72%	72%	72%	71%	70%	70%
AW07	Summer	122%	120%	121%	121%	122%	124%
	Winter	72%	71%	71%	71%	71%	72%
BD08	Summer	80%	81%	81%	80%	80%	80%
	Winter	79%	80%	80%	79%	78%	78%
BD13	Summer	75%	71%	79%	81%	82%	83%
	Winter	80%	76%	84%	87%	87%	87%
CS02	Summer	91%	91%	92%	90%	90%	90%
	Winter	56%	57%	56%	55%	55%	55%
CS05	Summer	81%	80%	84%	88%	91%	95%
	Winter	56%	56%	58%	61%	62%	64%
COO11	Summer	103%	115%	130%	142%	154%	168%
	Winter	85%	95%	106%	116%	124%	135%
COO22	Summer	71%	73%	79%	83%	85%	89%
	Winter	62%	64%	68%	72%	73%	75%
EP9	Summer	79%	86%	93%	97%	96%	96%
	Winter	87%	94%	101%	105%	103%	103%
EP34	Summer	106%	104%	103%	101%	100%	100%
	Winter	81%	79%	78%	76%	75%	74%
ES15	Summer	86%	88%	93%	95%	97%	99%
	Winter	44%	45%	47%	49%	49%	50%
ES22	Summer	106%	105%	104%	102%	102%	102%
	Winter	98%	97%	95%	93%	92%	91%
FE06	Summer	84%	88%	103%	119%	130%	143%
	Winter	69%	73%	84%	97%	105%	115%
FF87	Summer	65%	72%	79%	87%	93%	100%
	Winter	61%	67%	74%	81%	86%	92%
FF95	Summer	100%	131%	190%	251%	299%	365%
	Winter	75%	98%	140%	185%	219%	265%
FT21	Summer	92%	95%	98%	100%	101%	103%
	Winter	77%	80%	81%	83%	83%	84%
FT31	Summer	76%	75%	79%	84%	89%	94%
	Winter	75%	74%	78%	83%	87%	91%

Feeder	Season	10% POE Demand Forecast					
		2020	2021	2022	2023	2024	2025
HB15	Summer	91%	92%	97%	102%	106%	111%
	Winter	65%	65%	68%	72%	74%	77%
NS11	Summer	81%	86%	94%	97%	101%	105%
	Winter	64%	69%	75%	78%	80%	83%
NS12	Summer	68%	69%	73%	75%	78%	107%
	Winter	35%	35%	37%	38%	39%	53%
NS15	Summer	89%	88%	89%	87%	87%	88%
	Winter	57%	57%	56%	56%	55%	55%
NS18	Summer	63%	74%	91%	109%	120%	132%
	Winter	47%	55%	68%	81%	88%	96%
NH02	Summer	104%	104%	104%	102%	102%	102%
	Winter	81%	82%	81%	79%	78%	78%
NH16	Summer	93%	94%	94%	92%	94%	97%
	Winter	61%	62%	61%	60%	61%	63%
NT11	Summer	95%	96%	97%	96%	95%	95%
	Winter	75%	76%	76%	75%	74%	74%
NT15	Summer	73%	81%	90%	94%	99%	104%
	Winter	64%	72%	79%	82%	85%	90%
NT17	Summer	109%	113%	118%	119%	119%	120%
	Winter	93%	96%	100%	101%	100%	100%
ST32	Summer	101%	113%	126%	136%	143%	150%
	Winter	69%	77%	85%	92%	96%	100%
ST33	Summer	101%	103%	106%	105%	105%	106%
	Winter	53%	54%	55%	55%	54%	55%
ST34	Summer	68%	67%	73%	80%	86%	93%
	Winter	65%	64%	69%	76%	81%	87%
YVE21	Summer	84%	103%	129%	154%	185%	218%
	Winter	73%	89%	111%	133%	158%	185%
YVE22	Summer	98%	101%	104%	102%	101%	102%
	Winter	83%	87%	88%	87%	85%	85%