Jemena Electricity Networks (Vic) Ltd

Network Performance Plan 2021 - 2025

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Abbreviations

ACR	Auto Circuit Recloser
ACS	Asset Class Strategy
ADMD	Average Diversified Maximum Demand
AER	Australian Energy Regulator
ASC	Arc Suppression Coil
CAIDI	Customers Average Interruption Duration Index
CBRM	Condition Based Risk Modelling
CMOS	Customer Minutes off Supply
CRO	Caution Re Operation
EDPR	Electricity Distribution Price Review
EG	Embedded Generation
GSL’s	Guaranteed Service Levels
HBRA	Hazardous Bushfire Risk Area
HV	High Voltage
HVI	High Voltage Injection
JCARS	Jemena Compliance and Risk System
JEN	JEN Electricity Network
LBRA	Low Bushfire Risk Area
LV	Low Voltage
LVABC	Low Voltage Aerial Bundled Cable
MAIFI	Momentary Average Interruption Frequency index
OMS	Outage Management System

POS	Point of Supply
PQ	Power Quality
PV	Photovoltaic
QOS	Quality of Supply
RCM	Reliability Centred Maintenance
REFCL	Rapid Earth Fault Current Limiter
RMU	Ring Main Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	System Control and Data Acquisition System
ST	Sub Transmission
STPIS	Service Target Performance Incentive Scheme
VCR	Value of Customer Reliability
VEDC	Victorian Electricity Distribution Code
VOT	Voltage Optimised Transformer

Overview

The performance of the JEN as discussed in this plan refers to the day to day operation of the network and its ability to deliver the energy required by the stakeholders while maintaining a range of operating parameters. The aspects of network performance that are measured and regulated include:-

- Reliability;
- Supply Quality;
- Customer Service Levels;
- Safety;
- Asset Condition; and
- Regulatory Compliance.

All of these areas are related and are reliant on the safe and reliable operation of the network infrastructure.

Since the privatisation of the Electricity Industry the performance of the JEN as measured by a range of performance indicators has steadily improved. This has been due to the ongoing investment in maintenance of the network and a range of activities intended to address underperforming aspects of the network. This has involved replacement programs and modification to design and construction standards and material and equipment specifications. This work has been undertaken to ensure the integrity of the various network elements and thus address and reduce the causes of network outages.

In addition to the work designed to maintain and improve the network integrity a range of activities and programs have been implemented designed to reduce the impact of network faults when they occur. This has been focussed on limiting the area affected by a fault and restoring supply to affected customers as fast as is possible.

The characteristics of the JEN in terms of its construction type and geographic location in some ways impose a limit on ongoing improvement in network performance. The law of diminishing returns applies to the effectiveness of network performance improvement activities. There are a group of network outage causes that are out of the control of network operators and a number of these are variable year on year. These determine what may be considered the underlying performance level for the JEN. Certainly further improvement in network performance can occur but the focus is shifting to the maintenance of the existing performance levels in the face of changing operating conditions.

Customer Expectations

JEN has undertaken a customer engagement exercise to assess, among other things, JEN's customer's appetite for continued or improved levels of network performance. The results of this exercise indicate that JEN's customers are generally satisfied with the existing performance levels but do not want to see any reduction. They do expect that current network performance levels shall be maintained.

Service Target Performance Incentive Scheme (STPIS)

The STPIS scheme was introduced in 2000 to provide network operators with a "carrot and stick" incentive to improve the reliability performance of their networks. It facilitated the financial justification of projects that were intended to improve network reliability and could not be justified on the basis of increased network capacity.

Since the scheme was introduced JEN has consistently met or exceeded the targets for Unplanned Network SAIDI and SAIFI (16 of 19 years) and met the MAIFI target approximately 50% of the time. The targets proposed for the 2021 – 2025 period are set out in Table 1-1. These are the whole of network targets, details of the split of the targets into urban and rural categories are included in section 3. These targets have been arrived at by adopting the AER's methodology and current definitions.

Table 1-1 Performance Indicator Targets

Performance Indicator	2021-2026
SAIDI Unplanned	45
SAIFI Unplanned	0.73
MAIFI	0.99

Network Integrity

The prime driver or determinant of network performance is the number of high voltage outages that the network suffers each year. Since privatisation the number of outages that occur per annum has been trending down. This is testament to the effectiveness of the routine activities and targeted programs that maintain the network assets and address poor performing network elements.

This plan details a range of activities designed to maintain the integrity of the network. Principal amongst these are the condition based asset replacement programs that are applied to all asset classes. In addition there are a number of targeted programs aimed at addressing particular performance issues or managing major network risks including but not limited to:-

- Bird and Animal Proofing;
- Pole Top Fire Mitigation;
- Bushfire Mitigation;
- Electric Line Clearance;
- Conductor Clashing Mitigation; and
- A range of asset maintenance and condition monitoring/inspection programs.

Network Fault Impact

The two pillars that underpin overall network reliability performance can be described as prevention and recovery. Prevention being the activities that are designed to prevent faults occurring on the network. Recovery being those strategies or actions that are taken to limit the impact of a fault once it has occurred. This is achieved by either limiting the area affected by a fault or reducing the length of the outage time.

This section of the network performance plan discusses those strategies intended to reduce the impact of an outage once it has occurred. This primarily addresses the reliability performance of the network and the customer's guaranteed service levels.

The sectionalisation and automation of the feeder network using remote controlled gas switches and auto circuit reclosers (ACR's) has been the biggest single contributor to the improvement in overall network performance that has occurred on the JEN. The deployment of this equipment has allowed large high customer number HV feeders to be sectionalised into manageable zones and has facilitated the reduction in numbers of customers effected by network outages and the rapid restoration of supply to customer not located directly within the faulted zone.

The plan outlines the activities planned to maintain overall network performance at current levels in an environment where the growth in customer numbers serviced by the network is not uniform and is concentrated in a small number of high growth corridors.

It also includes plans to address performance issues associated with the function of some ACR's. The plan includes the details of the following activities:-

- Deployment of additional ACR's and the modification of existing installations;
- The maintenance of fault indicators and the deployment of further remote monitoring fault indicators;
- The deployment of remote controlled ring main units (RMU's) and HV circuit breakers in the HV underground parts of the distribution network; and
- Plans to leverage of the remote controlled network to facilitate the implementation of "self-healing network" technologies.

Power Quality Compliance

This section of the network performance plan discusses those issues that impact upon supply quality and the strategies intended to monitor, maintain and rectify power quality issues on the JEN. This primarily addresses the regulated supply quality parameters of:-

- Steady State Voltages;
- Voltage Variation (Sags and Swells);
- Harmonic Distortion (percentage);
- Voltage Unbalance (Negative Sequence);
- Voltage Fluctuations (Flicker); and
- Transient Overvoltage (Switching Transients).

The two major issues that will impact on this aspect of network performance are:-

- The availability of network supply quality data at the individual customer level facilitated by the roll out of smart meters; and
- The forecast exponential growth in embedded generation (EG) systems as a result of the Victorian Governments Solar Homes Program.

The rapid growth in numbers of EG system installations is expected to bring with it a similar growth in supply quality complaints. The current population of 33,000 installations is forecast to grow to 139,000 by the year 2027. Correspondingly the number of verified steady state voltage complaints associated with these installations is expected to grow from the current rate of 89 annually to 400 per annum by 2027. The works required to rectify these issues is also forecast to grow correspondingly.

Capital Works Proposal

The proposed capital works program aimed at addressing issues that directly impact performance of the network are summarised in Table 1-2. This will enable JEN to maintain current performance levels with respect to reliability, quality of supply and regulatory compliance. This expenditure is a subset of overall capital program which is covered in Electricity Asset Class Strategies and includes lifecycle management of electricity distribution assets.

Table 1-2 Capital Summary

Performance Indicator	Forecast Capital Expenditure ($2019 '000s, direct escalated cost, including overheads)					
	CY21	CY22	CY23	CY24	CY25	Total
Asset Replacement	$4,016	$3,960	$4,500	$4,658	$4,061	$21,195
Birds and Animals	$34	$34	$35	$35	$36	$174
Pole Fire Mitigation	$1,876	$1,870	$1,899	$1,947	$1,962	$9,554
Conductor Clashing	$39	$39	$40	$41	$41	$199
Feeder Exit Re-arrangement (substation BY)	$200	$0	$0	$0	$0	$200
Overloaded Transformers	$2,926	$2,912	$2,952	$3,021	$3,040	$14,850
Remote Control and Automation	$612	$609	$617	$631	$635	$3,104
Supply Quality Augmentation	$730	$801	$813	$833	$838	$4,015
Totals	**$10,434**	**$10,225**	**$10,855**	**$11,165**	**$10,612**	**$53,290**

1. Objective

The objectives of the Network Performance Plan are to:

- Detail the historic performance of the network in terms of a number of reliability indicators;
- Provide a forecast of future network performance;
- Describe the known issues likely to impact on network performance;
- Provide details of the plans, programs and strategies proposed to deliver and maintain the forecast network performance; and
- Detail the scope of the capital and operational budgets proposed to maintain the forecast network performance.

2. Background

2.1 Network Description

JEN covers an area of some 950 square kilometres located northwest of Melbourne. It services approximately 360,000 commercial, industrial and residential customers via a network comprised of approximately 6,776 kilometres of overhead and underground power lines (excluding services). The distribution network is connected to transmission system (terminal stations) via 46 subtransmission lines at 26 zone substations. The energy is then distributed to JEN's customers via 221 high voltage feeders and 6547 distribution substations. The summated maximum demand on the network is approximately 975 megawatts and the network delivers approximately 4,200 GWh's of energy per annum.

The subtransmission network operates primarily at 66kV with a small number of 22kV lines. The high voltage feeders operate at 22kV, 11kV and 6.6kV. The low voltage network operates at 400/230 volts.

2.2 Network Performance Methodology

Network performance in the context of this plan refers to the day to day operation of the network and its ability to deliver the energy required by the stakeholders while maintaining a range of operating parameters. The performance is monitored using a range of indicators and targets which form the basis for the planning and management of the network. These network performance indicators cover the following areas:

- Reliability;
- Supply Quality;
- Customer Service Levels;
- Safety;
- Asset Condition; and
- Regulatory Compliance.

In order to optimise Network Performance the following methodology is applied:

2.2.1 Monitor Performance

The performance of the network is monitored utilising the following data and information systems, analysis and reporting tools and processes.

- SAP Business Objects;
- OMS;
- CMOS;
- Daily Situation Reports;
- Incident Investigations and Reports;
- Customer Meter Data;
- VCR (Value of Customer Reliability);
- Customer Complaints;
- PQ Nodes; and

- Asset Performance Meetings (monthly).

2.2.2 Analyse

The performance of the network is analysed to identify issues impacting on network performance.

2.2.3 Develop Mitigation Strategies

Strategies are developed to address identified issues affecting overall network performance and performance affecting individual customers.

2.2.4 Influence

The result of the analysis and the strategies developed are used to influence the following:

- Planning Standards;
- Design Standards;
- Material and Equipment Specifications;
- Construction Standards and Methods;
- Maintenance Practices and Programs;
- Operating Practices and Procedures; and
- Contingency Plans.

2.2.5 Secure budget for programs and strategies

Provide input into the annual budgeting cycle and network planning activities.

2.2.6 Monitor performance

The feedback activity that facilitates continuous improvement.

2.3 Network Performance Indicators

2.3.1 Reliability

Network reliability is influenced by:

- The age and condition of the network;
- The level of redundancy in the design and operation of the network;
- The standard of day to day network management and monitoring;
- Response times and the availability of field resources; and
- The environment in which the network operates.

The environment is the largest factor affecting the performance of the JEN. By network length approximately two thirds of the JEN is comprised of overhead power lines and consequently it is exposed to a range of environmental and third party factors that impact on network performance. These include:

- Weather;
- Birds and animals;
- Vandalism;
- Vegetation; and
- Vehicle impacts.

Of these, the largest impact is weather and associated events such as storms, tree damage, drought and bushfire which can result in large variations in network performance year on year.

The reliability of the network is measured using a range of indicators, primarily the international and regulated measures used are:

- Unplanned SAIDI;
- Unplanned SAIFI;
- CAIDI;
- MAIFI;
- Planned SAIDI; and
- “S” factor associated with the Service Target Performance Incentive Scheme (STPIS).

2.3.2 Supply Quality

Supply quality in the context of this plan refers to the provision and maintenance of supply in accordance with a set of parameters that relate mainly to supply voltage. The principal parameters are:

- Steady state voltage level;
- Level of voltage unbalance for three phase supplies;
- Harmonic or voltage (waveshape) distortion level;
- Level and duration of transient voltage excursions; and
- Voltage fluctuations (Flicker)

The Electricity Distribution Code sets out limits for these measures.

2.3.3 Customer Service Levels

In order to give individual network customers some visibility in the context of overall network performance the Essential Services Commission (ESC) requires that the supply reliability for individual customers be monitored on an annual basis. The regulator requires that individual customers who suffer excessive numbers of unplanned supply interruptions or extended unplanned outage periods during a calendar year be compensated financially. These are known as Guaranteed Service Levels (GSL’s) and targets are set by the regulator for GSL payments.

GSL's targets are set for the following:

- Supply Restoration – total number of hours off supply per calendar year;
- Low Reliability – number of sustained interruptions per calendar year ; and
- Low Reliability – number of momentary interruptions per calendar year.

In addition to the GSL's that relate to supply reliability there are a number of GSL's that relate to the performance of the business in its dealings with customers. Public lighting repairs, appointments, etc.

2.3.4 Safety

In the context of this plan, safety refers to the safe operation of the network in terms of personal injury or loss or damage to the environment as a result of contact with or failure of an element of the network. The measures used are:

- Number of fatalities or injuries due to contact with the network; and
- Number of environmental infringement notices.

2.3.5 Asset Condition

Overall asset condition is a function of the asset age and the effectiveness of asset inspection and maintenance programs. Individual electricity assets have long lives (typically in the order of fifty years). JEN uses a number of tools and programs such as Reliability Centred Maintenance (RCM) and Condition Based Risk Modelling (CBRM) to assist with the condition monitoring and assessment of the network elements and these help inform the asset replacement programs and budgets. Actual asset replacement programs however are based wherever possible on asset condition monitoring programs.

The measures used to monitor overall network asset condition are:

- Number of HV faults due to equipment failure per 100km of network length; and
- Annual number of high voltage faults due to equipment failure.

2.3.6 Regulatory Compliance

A number of aspects of the overall performance of the network are mandated in a range of Acts and Regulations. These included technical performance standards. The various asset management systems applied by JEN are designed to ensure good governance and the maintenance of compliance across the range of regulated performance parameters. These include but are not limited to regulated performance levels in the following areas:-

- Network Reliability – SAIDI, SAIFI, MAIFI targets;
- Supply Quality – Voltage levels and ranges;
- Customer Service – Guaranteed Service Levels;
- Safety – Clearance of lines; and
- Asset Condition – Bushfire Mitigation Regulations, Public Lighting Code.

The Jemena Compliance and Risk System (JCARS) is used to monitor, measure and report on regulatory compliance across the range of regulation that impacts on the operation of the network.

2.4 Historical Network Reliability

2.4.1 Network Faults

The data included in Table 2-1 below gives details of the historical outages that have occurred on the JEN distribution network effecting high voltage feeders or parts thereof. It does not include data on individual distribution substation outages that effect only a single substation. This is the high level outage data giving details of those outage events that have the largest impact on overall network performance.

As can be seen from the table the largest cause of network outages is the weather and weather related events, followed by birds and animals. The other significant component of the outage data are those outages where no cause is found. These are often transient type faults and can reasonably be attributed to the effects of vegetation, birds and animals and third party interference or vandalism.

The other significant group of outages are those that are related to equipment failure to which underground cable failure and pole fires can be added to give a clearer picture of the overall effect asset condition is having on network performance. In total this represents approximately 20% of all outage causes.

Table 2-1 Historical Network HV feeder Outages by Cause

Outage Cause	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Birds and Animals	54	49	35	50	55	49	65	49	68	474
Equipment failure	34	29	28	23	29	31	23	20	15	232
Underground cable failure	22	13	20	20	19	10	17	14	18	153
Underground cable dig-in	1	3	3	2	1	1	1	1	1	14
Pole Fire	5	5	7	34	21	12	5	1	4	94
Third party impact	5	9	6	10	4	11	12	21	12	90
Operational error	8	7	6	1	2	4	4	5	5	42
Vandalism	3	7	4	10	4	4	3	2	5	42
Vegetation	8	7	8	13	16	7	9	8	10	86
Vehicle	23	31	27	22	24	29	28	38	22	244
Weather	82	69	49	71	89	50	65	40	51	566
Miscellaneous	5	4	2	7	6	7	9	7	9	56
No identified cause	58	47	37	43	38	48	52	53	56	432
Total	**308**	**280**	**232**	**306**	**308**	**263**	**293**	**259**	**276**	**2525**

The above data has been normalised against network length and graphed below in Figure 2-1. The graph indicates the number of high voltage feeder outages per year per 100km of network length. It is possible to claim that there is a downward trend in the rate that these outages are occurring. The average annual number of outages equates to less than one HV outage per day over the period under review.

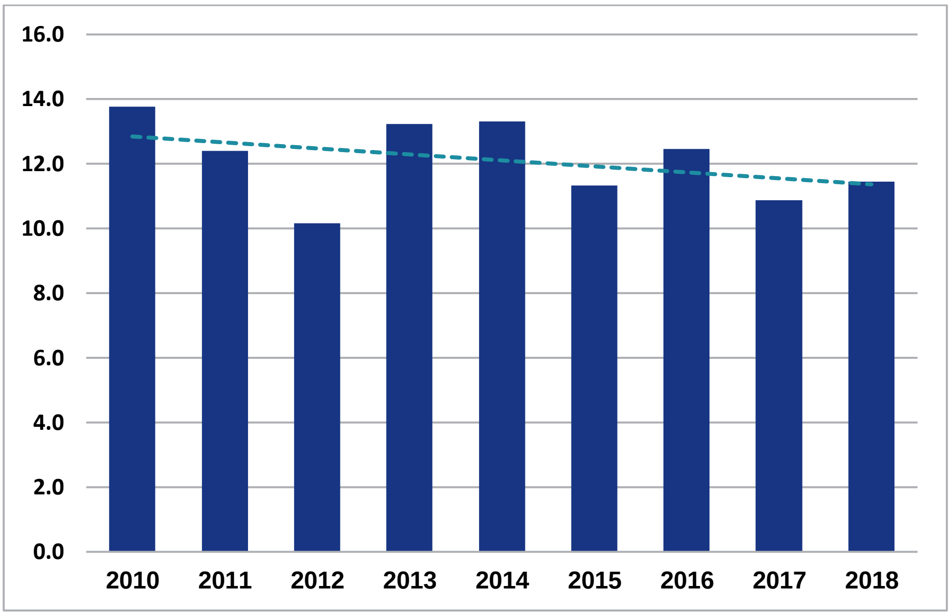

Figure 2-1 HV Outages per year per 100km of Network Length (includes sustained and momentary interruptions)

2.4.2 Equipment failures

The rate at which high voltage outages occur due to the in-service failure of network assets is a good indicator of asset condition. In Figure 2-2 the rate at which equipment failures occur is normalised against network length to give an asset condition index. It can be seen that this indicator has been trending down.

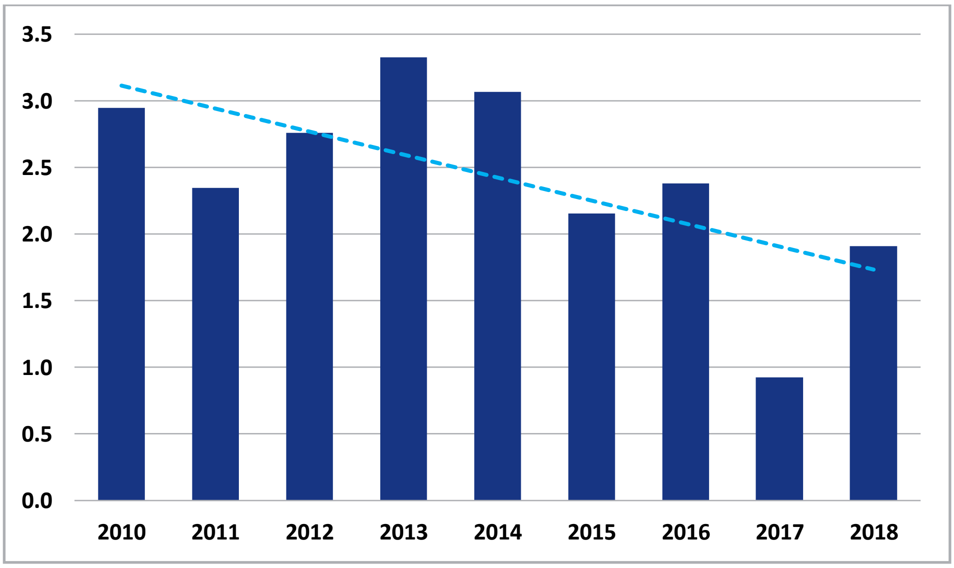

Figure 2-2 Historical HV Equipment Faults per 100km of Network Length (includes sustained and momentary interruptions)

The improving trend in the asset condition index indicated above is reflective of the general trend in the number of annual outages due to the in-service failure of equipment. The total number of outages per annum due to

equipment failure are indicated in

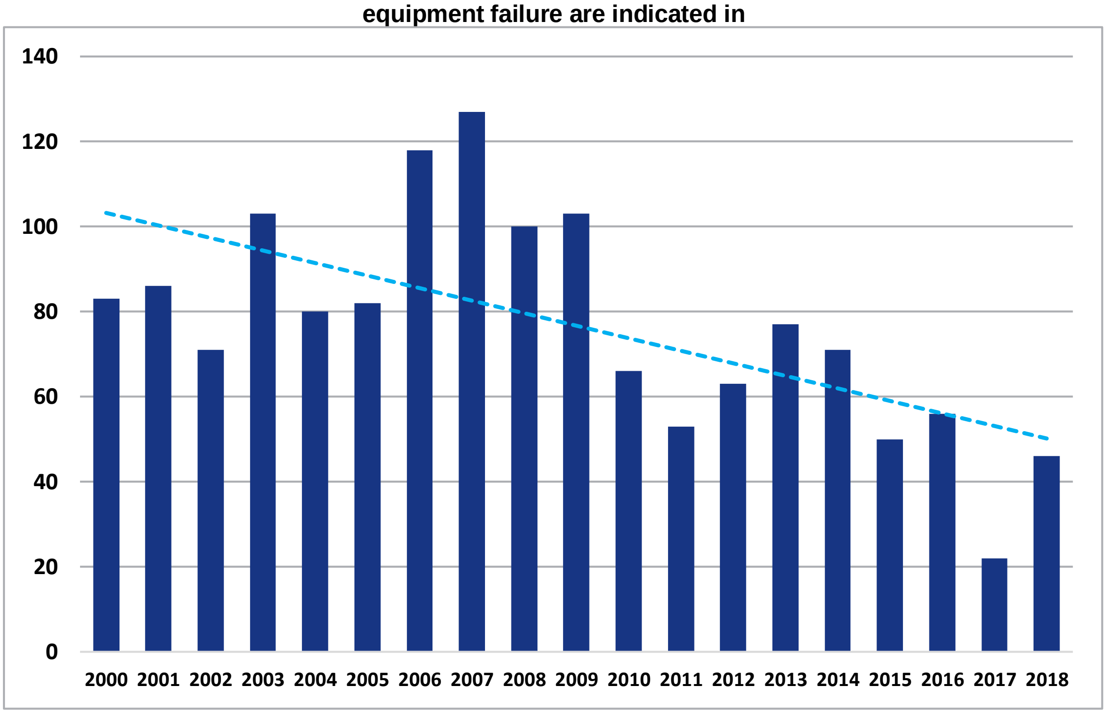

Figure 2-3. The number of outages is showing a decreasing trend despite the growth in network length that is occurring.

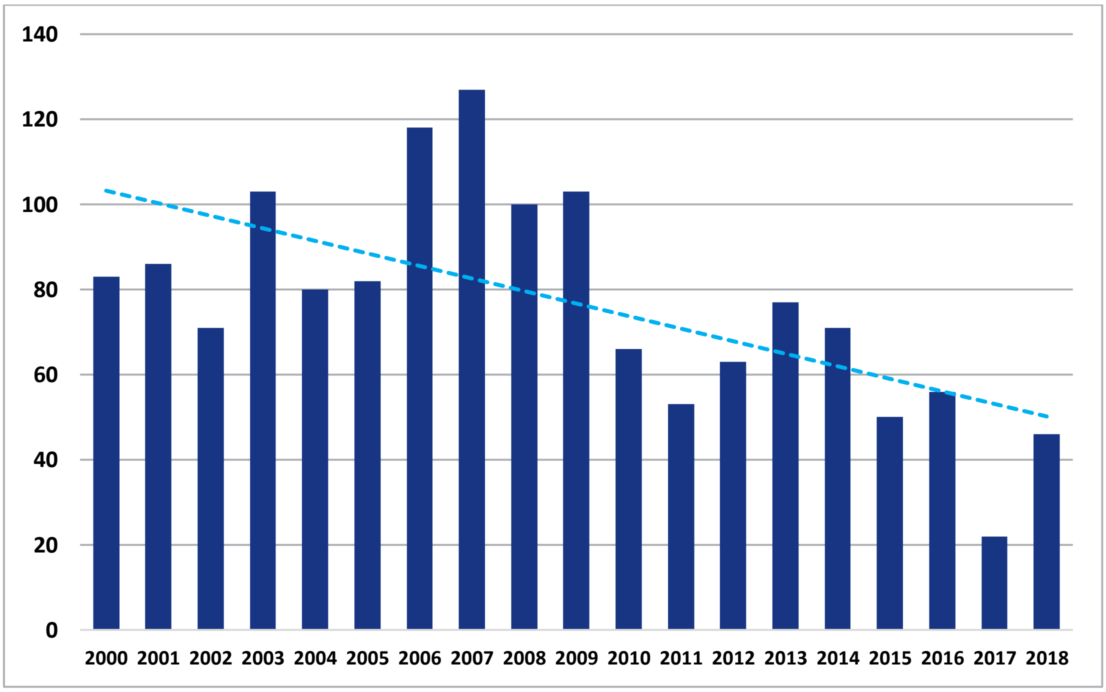

Figure 2-3 High Voltage equipment failures resulting in network outages (includes sustained and momentary interruptions)

2.4.3 Historical Unplanned Network SAIDI

Figure 2-4 below indicates the historical performance of the network, since privatisation, in terms of System Average Interruption Duration Index (SAIDI). This is a regulated network reliability performance indicator and is calculated by dividing the total duration of all sustained network outages for each customer (customer minutes of supply or CMOS) by the total number of network customers. It gives a picture of the average number of minutes that each customer connected to the JEN spent without electricity supply at their premises per calendar year.

The Australian Energy Regulator sets targets for this measure for each year. Individual targets are established for different customers types, urban and rural. The AER in assessing network performance will give exemptions for some large network events. These are given for network outages caused by upstream events and for outages caused by natural events that are outside the network operators control and result in large SAIDI scores (major event days). The size of these exemptions, where they have been granted, are also indicated on the chart below.

In addition to the unplanned SAIDI there is an allocation for CMOS associated with planned works that require the isolation of supply to allow the safe conduct of network augmentation and maintenance works. Total network SAIDI is therefore the sum of the Planned and Unplanned SAIDI.

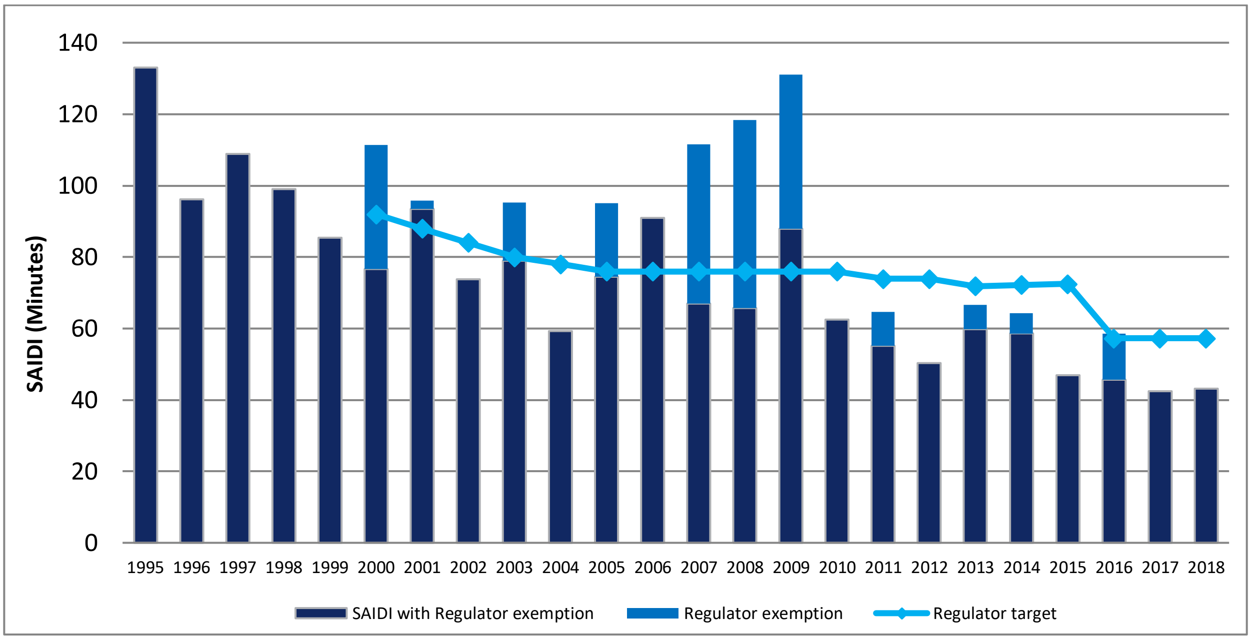

Figure 2-4 Historical Unplanned Network SAIDI 1995-2018 (based on historic definitions)

2.4.4 Historical Unplanned Network SAIFI

Figure 2-5 below indicates the historical performance of the network in terms of System Average Interruption Frequency Index (SAIFI). This is also a regulated network reliability performance indicator and is calculated by dividing the total number of individual customer sustained supply outages by the total number of network customers. This gives a picture of the average number of sustained outages each individual customer experienced in the calendar year under review.

Again the AER sets targets for each customer type, urban and rural, and the network as a whole. Exemptions also apply for this performance measure.

It can be seen from the historical SAIDI and SAIFI charts that in recent years the average customer experienced one unplanned sustained supply outage per year with a duration of approximately 60 minutes.

In recent years the JEN as a whole has achieved its target performance levels for both SAIDI and SAIFI.

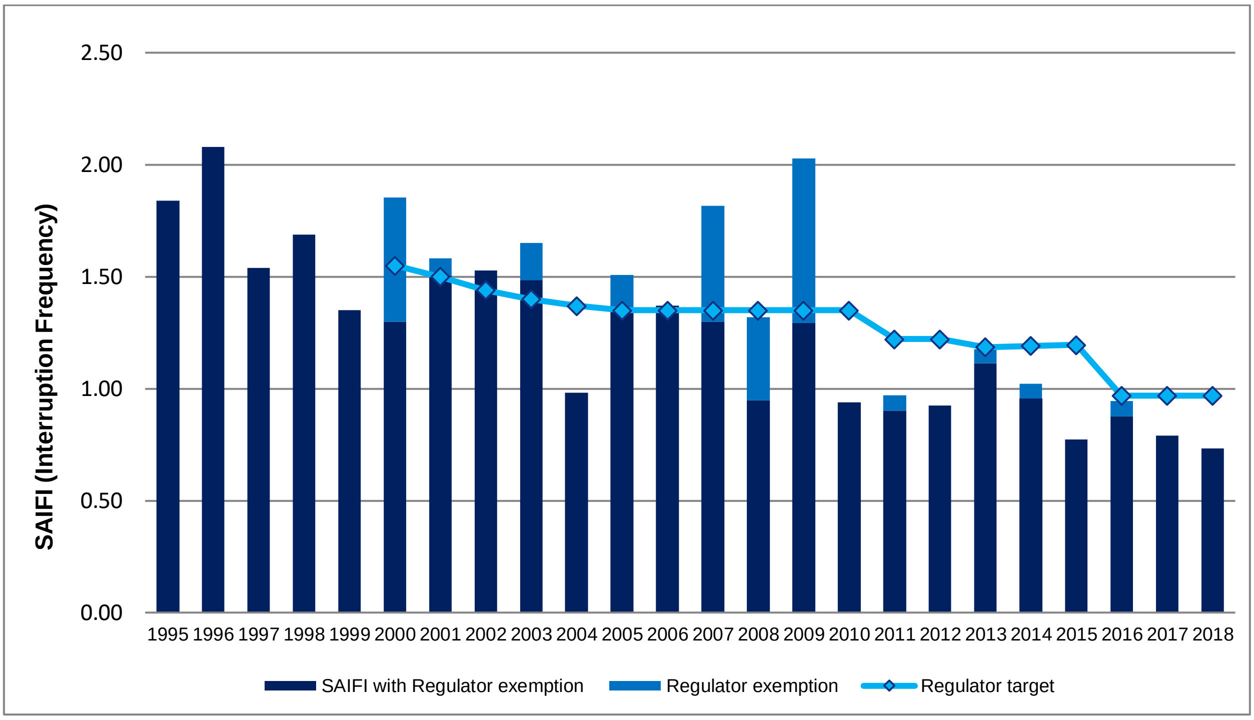

Figure 2-5 Historical Unplanned Network SAIFI 1995-2018 (based on historic definitions)

2.4.5 Historical Network MAIFI

Figure 2-6 below indicates the historical performance of the network in terms of Momentary Average Interruption Frequency Index (MAIFI). This is a whole of network regulated reliability performance indicator and is calculated by dividing the total number of individual customer momentary supply outages by the total number of network customers.

Historically a momentary interruption was defined as a supply outage of one minute duration or less. Commencing in the 2021 – 2026 regulatory period a new regulatory definition will be implemented. For this period a momentary outage is defined by the regulator as an outage of three minutes or less. This change has been made to acknowledge the capabilities of self-healing network technologies.

In recent years the JEN has performed close to the regulated target as can be seen on the chart below. In summary the average customer has experienced one momentary outage per year and one sustained outage of approximately 60 minutes duration per year.

Higher MAIFI is consistent with the success of network automation and fault reclose systems. The successful function of reclose facilities is an indicator of the durability of network assets. It points to the reduction in fault levels and energy associated with the deployment of neutral earthing resistors and the success of initiatives to reduce conductor clashing and replace weak non-tension connections on the high voltage network.

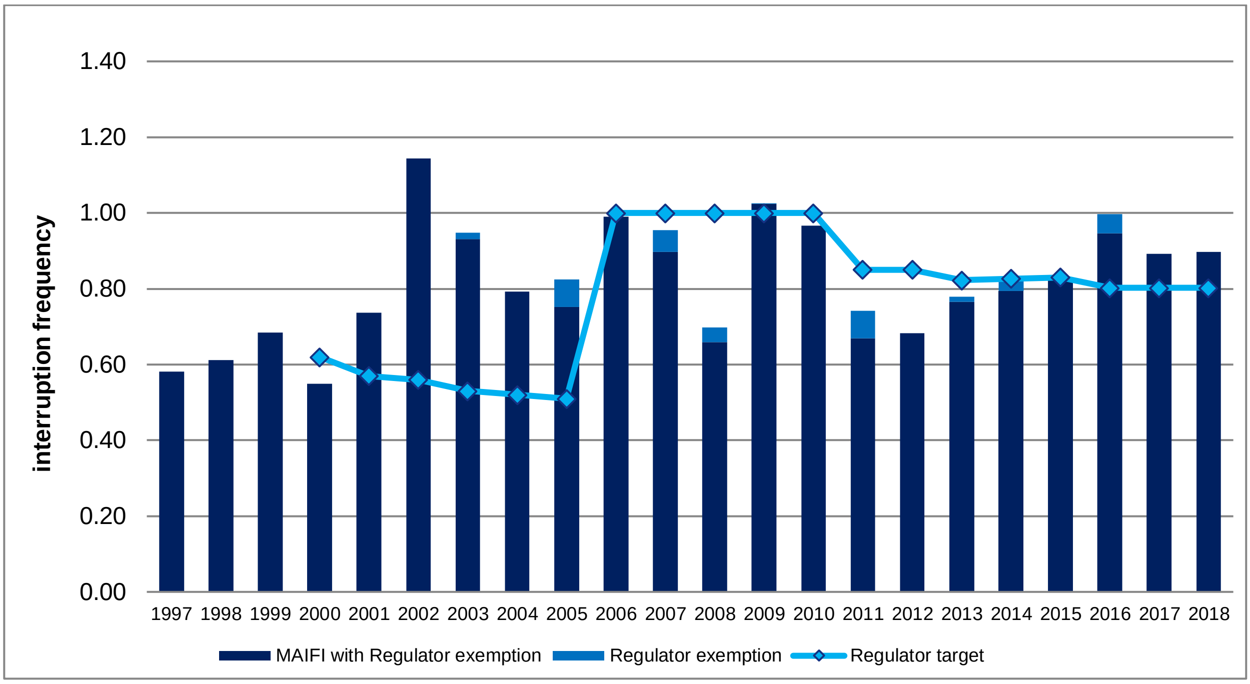

Figure 2-6 Historical Unplanned Network MAIFI 1997-2018 (based on historic definitions)

3. STPIS

The Service Target Performance Incentive Scheme (STPIS) is overseen by the AER and is used to reward/penalise network operators based upon the achievement or otherwise of:

- the target reliability performance indicators for the network; and
- a range of Customer Service Level indicators.

This scheme facilitates the justification of network performance improvement programs based on the financial impact of achievement or otherwise of the regulated reliability targets. It provides a financial incentive for projects that may not be justified purely on the basis of network capacity drivers.

The scheme provides incentives to improve and maintain overall network performance by implementing reliability targets for the network as a whole and also provides incentives to maintain performance at an individual customer level via the Guaranteed Service Level payment scheme.

JEN has consistently performed better than the targets set as part of the STPIS scheme as a result of the success of the various initiatives undertaken to improve the reliability performance of the network. Consequently the scheme has rewarded JEN for the performance improvements achieved.

3.1 Historical

The historical network reliability performance are summarised below.

Table 3-1 Historic Network Reliability Performance (Excluding upstream and major event days)

Performance Indicator	Actual											
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
SAIDI - Total	76	76	98	80	76	72	83	85	77	75	68	70
SAIDI - Unplanned	67	66	88	62	55	50	60	59	47	46	42	43
SAIDI - Planned	9	11	10	18	20	21	24	27	30	30	25	27
SAIFI - Unplanned	1.30	0.95	1.29	0.94	0.90	0.92	1.11	0.96	0.77	0.88	0.79	0.73
CAIDI - Unplanned	52	69	68	67	61	54	54	61	61	52	54	59
MAIFI	0.9	0.66	1.02	0.97	0.67	0.68	0.77	0.79	0.82	0.95	0.89	0.90

Figure 3-1, Figure 3-2 and Figure 3-3 show the network reliability performance, as measured by the supply reliability indices, together with the targets for the evaluation of STPIS for the period 2014 through to 2025. The indices and targets for this period have been calculated using the new definitions that the AER will apply for the regulatory period (2021 – 2025). The dark blue bar represents the impact of excluded events. An exemption application is required for each excluded event in accordance with the AER's requirements. Excluded events include upstream events and outages that are caused by natural events that are outside the network operators control and result in large SAIDI scores (major event days). A daily threshold is set for SAIDI which must be exceeded before an exemption will be granted.

The Service Target Performance Incentive Scheme commenced in the year 2000 and has been modified with each price reset since.

Figures 2.4 and 2.5, together with Figures 3.1 and 3.2 indicate the continuous improvement that has occurred in both the network SAIDI and SAIFI performance of the network over the years since privatisation of the Electricity

Industry. This has occurred in response to the initiatives and investments made over that time aimed at the improvement of the overall performance of the network. Substantial performance improvement has occurred but continued improvement in performance becomes less cost effective as the network performance levels asymptote toward a performance level that is determined by the network type and its local environment.

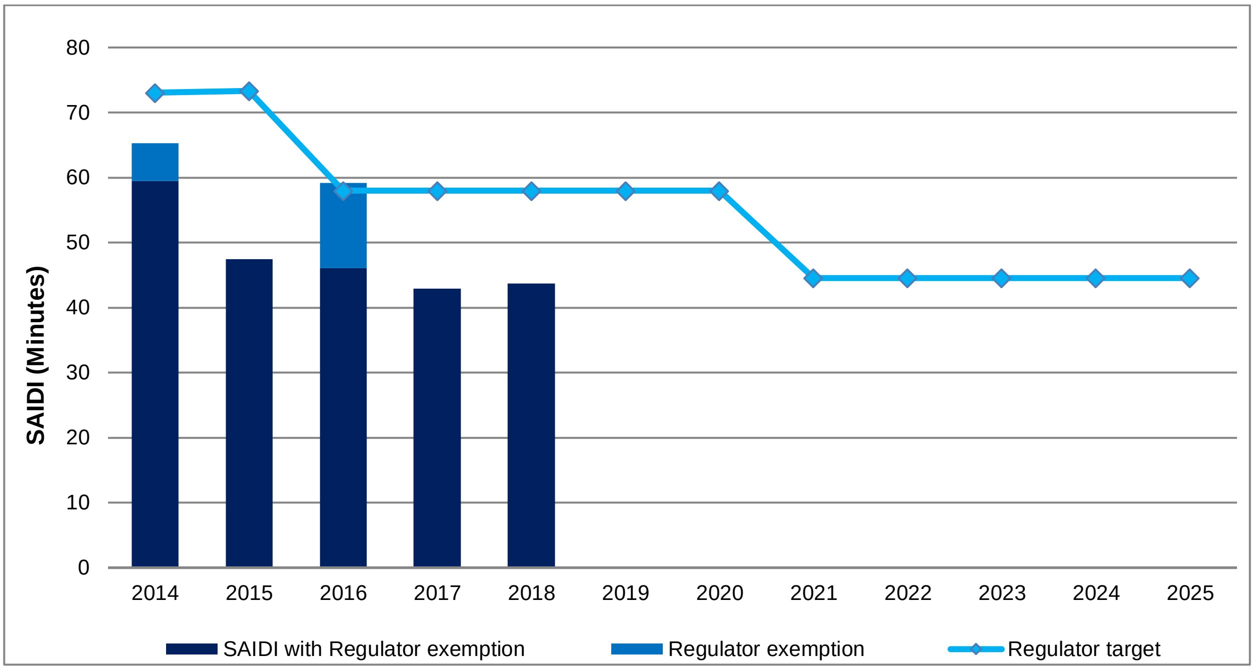

Figure 3-1 Unplanned Network SAIDI 2014 - 2025

Fundamental to the performance of the network is the number of network outages that occur each year. Work to reduce this number has focussed on particular outage types but there are a number of outage causes that are almost characteristic of the network and cannot be prevented economically.

These include the following outage types:

- Third Party interference;
- Operational errors;
- Vandalism;
- Vehicle impacts; and
- Weather

These account for approximately 40% of all HV network outages. Based on an average of 280 outages per annum then it could be argued that the minimum number of outages that the JEN could attain is in the order of 200 outages per annum. This would approximately relate to an estimated unplanned SAIDI of 28 minutes and an unplanned SAIFI of 0.52 outages.

This performance level could be considered the asymptote to which the overall performance of the JEN could approach.

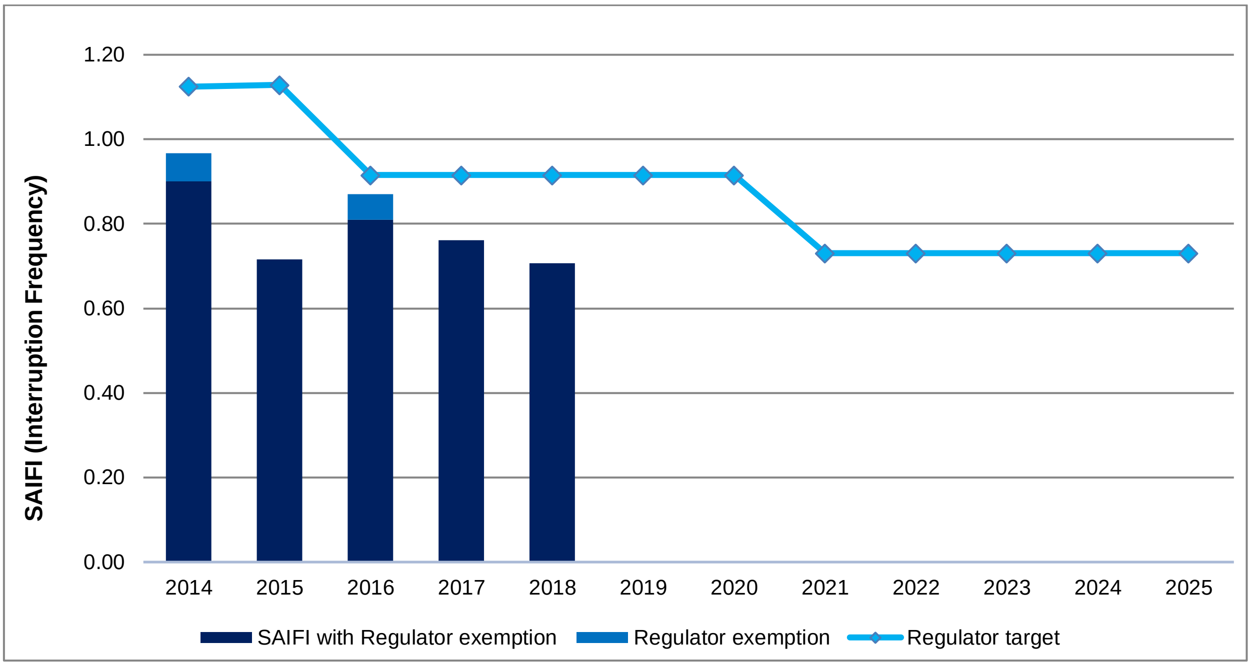

Figure 3-2 Unplanned Network SAIFI 2014 – 2025

MAIFI, as indicated in Figure 3-3, has increased since the introduction of a system wide policy on the implementation of reclose facilities. Auto-reclose has been commissioned on all feeder circuit breakers and auto circuit reclosers (ACR's) with the exception of those supplying underground networks exclusively. This has occurred in conjunction with the installation from mid-2002 of many ACR's on urban feeders to sectionalise and automate the feeder network. This has effectively turned a significant percentage of potentially sustained feeder outages into momentary outages effecting reduced numbers of customers. The impact has been to improve the networks overall SAID and SAIFI performance at the expense of the MAIFI performance. MAIFI has averaged around 0.9 interruptions per annum since then and is expected to increase further.

In addition, initiatives implemented to reduce secondary fault damage associated with failed non-tension connections and conductor clashing have further improved the networks SAIDI and SAIFI performance at the expense of the MAIFI performance.

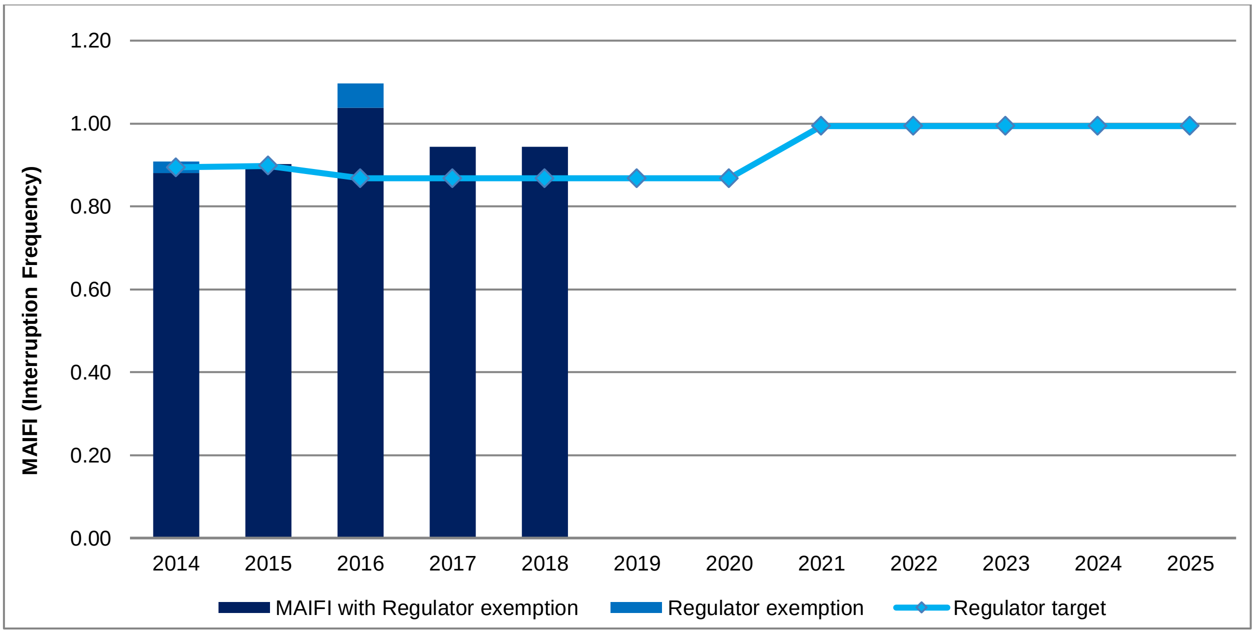

Figure 3-3 Network MAIFI 2014 -2025

3.2 New Regulatory Period 2021-2025

The aim for the new regulatory period is to maintain network performance at current levels and leverage of the work already done to improve performance by ensuring that capex investment in performance improvement is realised. This means that some initiatives will need to be implemented to ensure that the potential improvements in reliability offered by projects already delivered are realised in full. This is acknowledging the results of the customer engagement exercise that indicated that customers were generally happy with the network performance and were not prepared to pay for a further step improvement in reliability performance levels.

Prudent programs of work intended to address known fault causes will be undertaken to continue to drive down the number of network interruptions that occur each year.

Investment will continue on projects that will reduce fault impact cost effectively. In addition to the installation of ACR's and overhead line fault indicators, remote control switching and monitoring on indoor and kiosk substation switchgear will be installed in modest volumes as detailed later in this document. This investment is aimed at maintaining overall network performance by balancing the projected increase in customer numbers.

Table 3-2 below sets out the regulated reliability targets for the 2016-2020 period and the proposed reliability targets for the 2021–2025 regulatory period. These targets are estimated based on the AER methodology by averaging the historical performance for 2016, 2017 and 2018 and the forecast performance of 2019 and 2020.

Table 3-2 2016-2025 Reliability Targets – Unplanned

Annual Reliability Targets	Network (2016-20)	Urban (2016-20)	Rural (2016-20)	Network (2021-25)*	Urban (2021-25)*	Rural (2021-25)*
Unplanned minutes of supply (SAIDI)	57	55	92	45	44	47
Unplanned interruption frequency (SAIFI)	0.97	0.95	1.24	0.73	0.73	0.69
Unplanned interruption duration (CAIDI)	59	58	74	61	60	68
Momentary interruption frequency (MAIFI)	0.80	0.76	1.65	0.99	0.95	1.30

*All Targets for 2021-25 are set based on the new reliability definitions set by the AER

Table 3-3 below sets out the JEN's targets for planned SAIDI. These are based on the historical performance of the network and are related to the magnitude of the capital expenditure on the distribution system. Targets for 2016-2020 are forecast based on the EDPR proposed Capex. Targets for 2021-2025 are forecast based on the Capex program proposed for the 2021-2025 period. These targets will be reviewed annually.

Table 3-3 2016 - 2025 Reliability Targets - Planned and Total

Planned Minutes Off-Supply (SAIDI)	2016	2017	2018	2019	2020	2021-25
Network	32	34	26	28	29	36
Urban	30	32	23	26	27	32
Rural	69	65	63	64	68	104
Total Minutes Off-Supply (SAIDI)						
Network	89	91	83	85	87	86
Urban	85	87	79	81	82	80
Rural	161	157	155	156	160	192

4. Network Performance Plan

The network performance plan is comprised of three principle parts. These are:

1. Plans intended to maintain network performance by addressing network performance issues. This is achieved through programs and activities that mitigate identified factors that impact on performance. These range from maintenance and planning issues through to network or asset integrity issues.
2. Plans that are intended to mitigate the impact of network outages when they occur by limiting the number of customers effected or by minimising the duration of the outages.
3. Plans that are intended to identify, prevent and address supply quality issues.

4.1 Maintain Network Integrity

The integrity of the network is maintained by a range of activities and programs that address the need for ongoing maintenance and attention based primarily on condition assessments and by activities that are targeted at underperforming network elements. These are identified via monitoring and analysis of network performance.

4.1.1 Asset Replacement

4.1.1.1 Overview

The detailed maintenance and replacement strategies that underpin the performance of the JEN are detailed in the Asset Class Strategy (ACS) documents. Principally the Primary, Secondary and Distribution ACS's (ELE AM PL 0060 and ELE AM PL 0061). These documents detail the maintenance activities and asset replacement programs for all sub asset classes used on the JEN. The principle maintenance and replacement strategies applied to all asset classes are based on the principals embodied in the Reliability Centred Maintenance (RCM) and the Condition Based Risk Management (CBRM) methodology's that JEN utilises. These tools are used to inform the strategies adopted.

Consequently asset maintenance and replacement strategies utilise asset condition as the prime driver of programs wherever an effective and efficient condition monitoring measure is available. This ensures that assets are only replaced at the optimum time in the asset life. Condition monitoring programs are the largest part of the maintenance budget.

A small group of assets use a run to failure strategy but this can only be used where the consequence of failure is well understood and the failure has no safety consequence.

The CBRM methodology is used to inform decisions on asset replacement volumes in order to maintain network performance at the desired levels. It is used on a range of distribution assets and a number of primary (Zone Substation) assets. The methodology uses information on asset age and condition to develop a health index and an assessment of the consequence of failure and risk of failure to evaluate proposed interventions in terms of risk.

This program of works is the foundation for the maintenance of the performance of the network in all areas:-

- Safety;
- Reliability;
- Supply Quality;
- Customer Service Levels;
- Asset Condition; and

- Regulatory Compliance.

4.1.1.2 Response

The details of the budgets for the ongoing programs of asset condition monitoring, asset maintenance and asset replacement are detailed in the ACS documents covering the various asset classes.

4.1.2 Targeted asset replacement – premature failure / specific asset families identified through failure statistics

By monitoring the performance of the network it becomes apparent from time to time that some asset families are failing prematurely or in a manner that impacts the performance of the network or has unacceptable consequences of failure. JEN has undertaken a number of targeted asset replacement programs to address these types of issues over the years. The following are asset families that have been identified for targeted replacement:

4.1.2.1 Gas insulated Ring Main Units (RMU's):-

Early versions of the Merlin Gerin gas insulated RMU were supplied without any indication of gas pressure. The integrity of these RMU's is dependent on the maintenance of gas pressure within the unit and without a gas pressure gauge operators have no way of ensuring the integrity of the unit prior to performing any operation. A program has been established to retire all RMU's that do not have gas pressure indication (all makes) as they are identified either via the substation inspection program or when reported by operators. An examination of GIS records indicate that there are in the order of 27 of these units still in service. It is planned that they be retired during the 2021-2026 period. The principal driver of this program is safety, it is not expected to materially change overall network reliability performance.

4.1.2.2 F & G Ring Main Units:-

F & G RMU's were purchased in the 1990's for use in indoor distribution substations at both 22kV and 11kV. When operated at 22kV these units suffered a partial discharge problem in the HV fuse compartment. Modifications were made to the fuse compartments in an attempt to rectify the issue but this has not proved to be a long term solution. Tracking is occurring on the insulating surfaces in the fuse compartment and these RMU's need to be retired. There are three units operating at 22kV. These units are to be replaced in conjunction with the RMU replacement program detailed above.

4.1.2.3 Iljin gas switch:-

An issue with the Iljin pole mounted gas switches used on the 22kV and 11kV networks has been identified by operators. The issue relates to the position indicator on the switches. The issue has been resolved via the implementation of an operational procedure.

4.1.2.4 HV CABUS TYPE OUTDOOR CABLE TERMINATIONS

CABUS type high voltage cable terminations are a type of pitch filled cable termination enclosed in a cast iron housing. They have a history of explosive failure that results in the shattering of the cast iron housing with the attendant risk of damage and injury. A project has been implemented aimed at the retirement of all of these terminations. The program has been prioritized based on operating voltage and fault level (proximity to the zone substation).

The project has reached a stage where all 22kV installations have been replaced due to their criticality. There are 133 remaining installations at either 11kV or 6.6kV. Plans are in place to retire the existing 6.6kV areas around Preston and East Preston Zone Substations and the HV CABUS terminations in Preston and East Preston will be removed as a result.

This leaves the 11kV HV CABUS terminations to replace. A total of 111 11kV terminations have been identified for replacement. Work has commenced on the replacement of these terminations. It is proposed that the program continue until all terminations of this type are removed from the network. The principal driver of this program is safety, it is not expected to materially change overall network reliability performance.

There is a family of HV and LV metal clad outdoor terminations that utilise fabricated metal housings. Although these are of a similar age to the CABUS terminations the consequence of failure is less. These are included in the population targeted above but have been allocated a lower priority.

4.1.2.5 ABB HV Isolators

A family of ABB isolators with manufacturing dates from 1996 have been found to fail in service or when operated. These failures resulted from the corrosion of metal components cemented in the porcelain insulators. The corrosion cause the expansion of the embedded components which resulted in the cracking and failure of the porcelain insulators. The location of the entire family of isolators was extracted from asset data bases and a program of replacement completed. Asset inspectors have been instructed to identify any remaining isolators that may have been missed in the replacement program and schedule these for replacement.

4.1.3 Animal Proofing

4.1.3.1 Overview

Bird and animal strikes on the high voltage distribution network come second to weather related outages amongst the biggest known causes of network outages on the high voltage distribution network. Consequently they are one of the largest single factors affecting overall network performance. Bird and animals strikes have accounted for approximately 19% of all HV network outages over the past eight years as indicated in the outage statistics included in Table 4-1.

Possums, larger birds and flying foxes or fruit bats are main animals that cause problems on the network due to their ability to reach large distances and access pole top structures; particularly on complex structures such as cable heads, pole type substations and switch structures. There have been incidences of fruit bats causing strikes mid span between phase conductors.

Table 4-1 Bird and Animal Strikes

Outage cause	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Birds and Animals	54	49	35	50	55	49	65	49	68	474
Total all outage causes	308	280	232	306	308	263	293	259	276	2525
% of all outages	17.5%	17.5%	15.1%	16.3%	17.9%	18.6%	22.2%	18.9%	24.6%	18.8%

4.1.3.2 Response

In order to mitigate this problem special attention is made to the design of pole top structures and the specification of network assets and hardware so as reduce the possibility of animal strike. Clearances between phases and to earth are maximised wherever possible and when clearances are reduced insulated covers are utilised.

JEN's "Animal and Bird Protection Procedure" (JEN PR 0065) describes in detail the procedures adopted by JEN to mitigate bird and animal interference on a comprehensive range of pole top structures and different pole types.

As can be seen from the outage statistics the rate at which these strikes occur has remained constant over the past eight years at approximately 50 strikes per year with no clear trend evident. Currently there are no targeted programs to proactively address bird and animal strikes. Rather when a strike occurs the site is inspected and the particular issue is addressed. In addition the pole and line inspection program should identify any damaged or dislodged bird and animal protection and this will be rectified in the course of normal maintenance activity. A budget allocation is made for installation and repair of bird and animal protection.

A watching brief is maintained on the development of none conductive poles and crossarms which have the potential to mitigate some types of bird and animal interference. At this stage however there is no proven technologies of this type available.

4.1.4 Pole Top Fire Mitigation

4.1.4.1 Overview

The occurrence of pole top fires on overhead distribution networks is related to a number of factors. Principally these are asset condition and environmental conditions. Pole top fires occur on overhead networks that have been historically constructed using timber as the principal structural material. On the JEN they occur mainly on those parts of the network operating at 22kV and 66kV although they can occur at lower distribution voltages. Unlike many other causes of network outages which occur randomly, pole fires, like storms, often result in multiple outages affecting different parts of the network all over the same period of time. This places a great strain on network resources and often has a large impact on overall network performance.

Pole fires result in damage to the structural elements supporting the overhead network. The consequences of these types of failures are multi-faceted. Firstly, and most obviously, fire ignition can have a widespread impact on customers, property and staff. Secondly, the risk of high-voltage injection (HVI) is very high during instances of burnt or broken crossarms or pole tops. Pole top fires also impact customer reliability and security of supply. The safety of JEN's customers, work crews and the distribution system continues to be the principle driver for investment in Pole Top Fire mitigation.

JEN is obligated to mitigate pole top fires under the "Electricity Safety (Management) Regulations 2009" through JEN's Electricity Safety Management Scheme. Pole top fire mitigation is part of complying with the technical standards which ensure the asset is designed, constructed, commissioned, installed, operated, maintained and decommissioned so to ensure the safety and safe operation of the applicable asset.

4.1.4.2 Root Causes

Pole top fires typically occur when a prolonged period of dry weather allows dust and other pollutants to accumulate on the insulator surfaces and then light rain or fog adds moisture to the pollutants. This significantly reduces the insulating properties of the insulators and enables surface leakage current to pass over the insulators (primarily phase to phase leakage current) and through the wooden structures via the metal hardware used on the poles (king bolts, crossarm braces, insulator pins, fuse mounting brackets etc.). In most cases arcing or heating occurs at the interfaces between loose metal components, where the leakage currents are concentrated, and the timber structural elements. This leads to charring or ignition of the crossarm or pole. Loose hardware results from the shrinkage of the timber elements over time due to the drying out of the timber. Pole top fire incidents are more prevalent around major roads and dust generating industries.

4.1.4.3 Current State

JEN has paid special attention to the design of its modern pole top structures in order to eliminate, as far as is possible, the risk of pole top fires. This has involved the use of steel crossarms and the bonding of all pole top hardware to control the flow of surface leakage currents and thus prevent pole fires. These designs are applied to all new pole top structures and to all crossarm replacement work. These designs were introduced in about 1995 and since this time there have been no timber crossarms installed on the JEN high voltage (HV) and subtransmission (ST) networks. This makes the youngest wooden crossarms and their associated insulators on the HV and ST networks in the order of 25 years old. Consequently the remaining population of wood HV and ST crossarms on the JEN are all of an age that makes them potential candidates for pole fires. The increasing risk of pole fires associated with the remaining ageing timber HV crossarm population needs to be balanced by a proactive, prioritised, ongoing replacement program.

A targeted pole fire migration program has been completed in the Hazardous Bushfire Risk Area (HBRA) with all wooden high voltage (HV) and sub-transmission (ST) crossarms in the HBRA replaced with steel crossarms.

JEN geographically mapped areas most at risk to assist in developing mitigation strategies. Analysis of failures have confirmed that the problems are typically concentrated along main roads, coastal areas and near dust generating industries, where higher levels of airborne pollutants are present. As a result, the continued focus of the pole top fire mitigation program has been on inspecting pole tops in targeted areas to identify evidence of arcing, charring, loose pole top hardware or significant deterioration of the insulators or crossarms.

JEN's analysis of pole top fires has identified two shed fog pin insulators (known as brown pin insulators) are commonly associated with the majority of recent pole top fires. These insulators were installed on the network prior to the 1980's and exist in large quantities. This information is being used to prioritise these structures when developing pole fire mitigation programs.

Historically JEN has carried out specific programs to reduce the impact of pole top fires on its network. The major action has been the targeted replacement of brown pin insulators and crossarms on sub transmission loops to mitigate the risk of losing supply to a Zone Substation. Also targeted programs to replace and tighten hardware on pole tops in high risk areas have been undertaken.

Table 4-2 Pole Fire Network Outages

Outage cause	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Pole Fire	5	5	7	34	21	12	5	1	4	94
Total all outage causes	308	280	232	306	308	263	293	259	276	2525
% of all outages	1.6%	1.8%	3.0%	11.1%	6.8%	4.6%	1.7%	0.4%	1.4%	3.7%

Although the table above indicates that pole fire events are a relatively small proportion of overall network outages the consequences of these outages are significant. The concentrated nature of the events means that resources are stretched and consequently the networks ability to respond appropriately are impacted. Added to this the high probability of the high voltage injection (HVI) of customers installations associated with these outages and the risk associated with the failure of structural elements in the public domain make the mitigation of these types of outages a high priority.

4.1.4.4 Response

JEN's Pole Fire Mitigation Strategic Planning Paper (ELE PL 0015) sets out the basis for the strategy to be adopted for the mitigation of pole fires on the JEN.

There are approximately 400 timber ST and HV crossarms located on 66kV ST poles, 125 timber 22kV ST crossarms and 9,554 HV timber crossarm in service on the JEN. Of those on the HV network approximately 5,848 are on the 22kV parts of the HV network. The lower distribution voltages (11kV and 6.6kV) are rarely affected by pole fires. The routine condition based crossarm replacement programs result in the replacement of approximately 30 ST crossarms and 400 HV crossarm annually and this number is expected to increase year on year as the timber crossarm population continues to age. In addition to this the pole fire mitigation program will replace approximately 350 crossarms per year over the course of the EDPR period. These replacements are prioritised based on the following factors:

- Voltage;
- Location;
- Insulator type; and
- Crossarm condition.

During the 2021-2025 period it is proposed that the pole fire mitigation program is prioritised as follows:

- All timber HV and ST crossarms mounted on 66kV timber poles be targeted for replacement as these subtransmission lines are critical to network security;
- All of the remaining 22kV ST crossarms also be targeted for replacement. These are also critical to network security; and
- The remaining population of 22kV timber crossarms on the distribution network based on location, insulator type and condition.

At this rate of ST and HV crossarm replacement it is anticipated that the associated risk of pole top fires will be managed and overall network performance maintained at current levels.

4.1.5 Bushfire Mitigation

4.1.5.1 Overview

JEN's Bushfire Mitigation Plan (JEN PL 0100) sets out the approach JEN takes to the holistic management of risk in the HBRA part of its network. The plan details the processes and strategies that are applied to network assets located within the HBRA with particular emphasis on the monitoring, inspection, maintenance and development of these assets and the particular strategies and technologies applied to mitigate the risk of fire starts in the HBRA. The plan also describes the capital works proposed to improve the network performance and mitigate the risk of fire starts in the HBRA. The plan ensures JEN's ongoing compliance with its regulatory obligations in relation to the management of its assets located in the HBRA. Principally these obligations are detailed in the following acts and regulations and their associated amendments:-

- The Electricity Safety Act 1998;
- Electricity Safety (Management) Regulations 2009;
- Electricity Safety (Electric Line Clearance) Regulations 2015; and
- Electricity Safety (Bushfire Mitigation) Regulations 2013.

4.1.5.2 Response

In order to continually improve the fire safety of the JEN design and construction standards have been developed and modified to ensure that all new low voltage construction within the HBRA is installed utilising underground or insulated overhead cable systems. All new pole top construction incorporates the use of insulated covers as standard to protect network assets from interference by birds and possums and these are being progressively fitted where justified, to existing structures.

Bushfire Mitigation and summer preparation activities are considered part of JEN's normal operating procedure and are included in both the Opex and Capex allocations each year.

A number of projects and initiatives have been identified to further mitigate the risk of fire start in the HBRA and these include the following:-

Steel Conductor Assessment Program

This program is designed to identify conductor (and related equipment such as conductor ties) that are unserviceable via a targeted asset condition inspection. Conductor that is unserviceable will be programmed for replacement. This will minimize the risk of in service asset failure due to corroded steel conductor and fittings.

Bare LV Mains Removal

There is 34km of LV open wire conductor located within the HBRA of the JEN. This conductor is often strung in long spans in the HBRA and consequently the potential for conductor clashing is elevated. Also there is no ability to reduce fault currents on the LV network as phase to neutral or earth currents are part of the normal operating environment and fuses are used as the primary method of network protection. Conductor or crossarm failure also has the potential to result in fire starts.

In the HBRA, replacing these assets with bushfire safe solutions such as LV ABC (Low Voltage Aerial Bundled Conductor), underground cable and additional small capacity substation transformers results in enhanced bushfire safety. Consequently JEN is planning for the removal of all such conductor in the HBRA over the next two regulatory periods.

Hazard Tree Assessment Program

The hazard tree assessment program is designed to assess the likelihood of a tree or limb failure causing vegetation contact with electrical assets so that appropriate measures can be taken before failure occurs. This program allows for the systematic identification of hazard trees on a two-year cycle. The identification phase includes a comprehensive assessment of hazard trees in the HBRA by an experienced arborist. The assessment registers these trees and allows for targeted implementation of measures to mitigate the likelihood of tree related fire starts in the HBRA.

Mitigation strategies may include asset relocation or undergrounding where restrictions are imposed on the cutting or removal of trees identified as high risk.

Application of a Pole Mounted Camera

The use of a camera mounted on an insulated telescopic operating stick provides asset inspectors and maintenance planners with the ability to assess pole top hardware using high quality images taken from above.

This provides a perspective of the pole top assets such as crossarms, switches, insulators and conductor ties which has previously been unavailable. This is an ongoing initiative to gather and store accurate data on the condition of pole tops on JEN and is designed to supplement and enhance the existing asset inspection program.

REFCL (Rapid Earth Fault Current Limiters) and ASC (Arc Suppression Coils)

The REFCL fire ignition test project initiated by the Department of State Development Business and Innovation (DSDBI) and conducted in 2014[1], confirmed that the REFCL technology reduces the fire ignition risk associated with bare-wire overhead power lines. Current government regulations have mandated the installation of REFCL for selected zone substations located in areas with extreme fire risk consequence. These regulations came into operation in May 2016 and the installation of a REFCL system has been mandated at the Coolaroo (COO) Zone Substation in the JEN. This work is programmed for completion in 2023.

JEN is completing the installation of a ASC (Arc Suppression Coil) system at its Sydenham (SHM) Zone Substation and plans to install a REFCL system at the Sunbury (SBY) Zone Substation during the 2021-2025 EDPR period. At the completion of these works the majority of the JEN network located in the HBRA will be protected by these systems. This will result in a step reduction in the risk of fire starts associated with phase to ground faults in the HBRA of the JEN.

As well as reducing the risk of fire starts these systems have the potential to improve supply reliability by reducing the energy in phase to ground network faults. This means that the network can potentially experience these types of faults and recover without a supply interruption. This network performance improvement may be offset however by a loss in the ability to discriminate phase to earth faults through series connected devices such as Auto Circuit Reclosers (ACR's). The net result may be no change to overall network reliability performance.

Any new zone substations, such as the proposed Craigieburn (CBN) Zone Substation, that service feeders in the HBRA will be designed with REFCL systems.

4.1.6 Electric Line Clearance and Inspection Program

4.1.6.1 Overview

The JEN Electric Line Clearance Management Plan (JEN PL 0101) sets out the asset management approach, processes and strategies adopted for electric line clearance management by JEN. The plan has been developed to ensure JEN's compliance with the Electricity Safety (Electric Line Clearance) Regulations 2015. These regulations, first released in 2010, increased the required clearance space between JEN assets and vegetation that had been traditionally used resulting in a surge in vegetation management activity and the need in some cases to implement a range of engineering solutions to ensure compliance could be achieved around sensitive vegetation.

4.1.6.2 Response

Where Vegetation Management alone cannot achieve compliance with the Electric Lines Clearance Regulations, an engineering solution is required. This may entail any of the following:-

- replacement of bare overhead lines with LVABC;
- installation of underground cable;
- the relocation of pole lines;
- the installation of additional service poles;
- the relocation of a point of attachment, or;
- some other engineering solution.

The electric line clearance engineering solutions program is an ongoing program of works. In the period under review the forecast volumes to be applied each year are lower than recent levels as a large volume of works have already been completed. There is still however, an ongoing need for an allocation of funds to manage the work that continues to be identified via the Vegetation Management process.

The volume of underground engineering solutions is forecast to increase as members of the public learn that this is a potential solution partially funded by JEN.

In the Hazardous Bushfire Risk Area (HBRA) locations requiring electric line clearance engineering solutions are delivered as a priority. Locations in the Low Bushfire Risk Area (LBRA) are delivered based on the date the location is inspected and the non-compliance is found.

4.1.7 Conductor Clashing Mitigation

4.1.7.1 Overview

Conductor clashing on the HV and LV overhead networks occurs when the clearance between conductors cannot be maintained generally due to the influence of some external stimulus. Typically conductor clashing occurs due to the effects of:-

- strong winds, in the case of LV conductors often involving tree damage or excessive tree and branch movement;
- the passage of fault currents and the associated electro-magnetic forces between conductors;

- impacts on supporting structures associated with third parties such as vehicles; and
- the deterioration or movement of supporting structures leading to a reduction in designed clearances.

Conductor clashing on the LV network is principally associated with strong winds and the associated effects that this has on vegetation. This results in localised outages or supply quality issues associated with flickering lights caused by intermittent fault currents. These types of events have a relatively minor influence in terms of the effect on overall network performance.

Conductor clashing on the HV network is primarily associated with the passage of fault currents and has a significant impact on network performance in terms of the extent and scale of an outage and the ability of the network to recover from an outage. Conductor clashing is not generally the primary cause of a network outage but rather the secondary damage that occurs as a result of the passage of fault current. The consequence of conductor clashing is often to change an event from one potentially only involving a momentary outage to an event involving a sustained outage or an outage unnecessarily affecting customers in a switching zone upstream of the faulted area.

In many cases conductor clashing can negate the benefits of the supply reliability improvements expected from initiatives such as the Auto Circuit Recloser (ACR) installation program. Thus this type of fault has a significant impact on supply reliability and supply quality. For this reason it is important that measures are taken to ensure that this type of fault is mitigated and that the mitigation techniques are understood and applied to new installations of in-line ACR's on distribution feeders. This also applies to increases in transformer capacity at zone substations that result in significant increase in fault levels. Immediately after faults that result in conductor clashing have occurred, the location of the conductor clashing must be identified and mitigation undertaken to prevent repeat events.

4.1.7.2 Response

The Conductor Clashing Mitigation Guideline (JEN PR 0501) sets out in detail the requirements for the development and maintenance of the network in order to address and prevent conductor clashing on both the HV and LV parts of the JEN.

On the LV network, in both the HBRA and LBRA areas, standard designs call for the application of LV spreaders in all spans of conductor over a nominated length. Pole and line inspectors also note the condition and placement of spreaders and raise maintenance notifications to ensure the integrity of these elements. Whenever LV faults occur, the remedial installation of spreaders will occur at the direction of maintenance planners.

Primarily HV conductor clashing occurs in the urban part of the HV network where fault levels are higher and service corridors are congested. In the HBRA larger span lengths, tighter conductor stringing, larger clearances and lower fault levels mean that conductor clashing does not generally occur. On the HV network each incidence of conductor clashing is examined and preventative measures engineered to prevent further incidence occurring.

As a normal part of the scope of works for projects that involve the increase in network fault levels or the installation of ACR's on the HV distribution network, studies, modelling and inspection of effected HV lines is required to ensure network performance is not impacted by conductor clashing and the benefits of improved network performance are realised.

The installation of ACR's can only achieve the potential benefits they are designed for if the integrity of the upstream network is maintained under fault conditions. This may involve measures such as the installation of HV spreaders, longer crossarms or new poles in order to mitigate the risk of conductor clashing. Modelling of conductor configuration and fault levels can assist in the identification of potential clashing sites but visual inspection by experienced staff can also often identify at risk construction and conductor configurations.

The budgets proposed for the 2021–2025 period include allowances for the reactive measures necessary to address conductor clashing issues as they occur. Historically these have occurred at a rate of approximately 1 per month. Budgets required to maintain network reliability such as ACR installations or Zone Substation Augmentation projects that result in increased fault levels should include allowances for the works necessary to identify and prevent conductor clashing.

4.1.8 Regular Asset Performance Review Meetings

4.1.8.1 Overview

The Charter for the Asset Performance Review Committee sets out the function and schedule of the monthly formal Asset Performance Review Meetings. These meetings review all incidents during the preceding month that resulted in network outages that impacted network performance or supply quality. The meetings are attended by a range of stakeholders including network operations, maintenance planners, network planners, standards engineers and asset performance engineers. Actions are assigned as a result of the review and tracked. The aim of the meetings is to understand the causes of network outages and to:-

- prevent repeat outages;
- identify defective or failing families of plant;
- identify common failure modes and develop strategies to combat these; and
- initiate programs designed to improve network performance.

4.1.8.2 Response

Recommendations, proposals and strategies are developed to address specific customer related problems or network issues impacting on supply and equipment quality, reliability and safety. These may take the form of asset replacement programs, network augmentation or re-configuration, design modification, standardisation proposals, equipment specification review or modification of maintenance plans.

In addition the committee:-

- Co-ordinates and/or undertakes major incident investigations and reports on findings and recommendations;
- Arranges for the investigation of all significant plant failures reported;
- Reports on system-wide performance trends including issuing the Network Reliability Performance Report monthly; and
- Initiates business cases for major reliability initiatives.

4.1.9 Overhead Switchgear Inspection Program

4.1.9.1 Overview

The safe and efficient operation of the JEN is dependent upon the availability of the various switching devices installed strategically throughout the network. As the network is primarily an overhead network the majority of these switches are pole mounted devices. The ability to reliably reconfigure the network and isolate damaged or faulted sections of the network is critical to the overall reliability performance of the network. The high voltage overhead switchgear or pole mounted switchgear installed on the HV network falls into three categories:-

- air break switches;
- isolators; and
- gas insulated switchgear.

The term air break switch is used to describe a family of three phase, air insulated, pole mounted switches that have some load breaking capability. The environment in which these switches are installed together with the complexity of the load breaking mechanisms makes this family of switches particularly susceptible to defect and in need of ongoing inspection and maintenance to ensure their safe operation.

High voltage overhead isolators or isolating switches are air insulated single phase switching devices. These are hook stick operated from the ground and have no load breaking capability although they can be used to break parallel current and de-energise short lengths of line. Care needs to be taken when using these devices on distribution networks particularly where these include lengths of underground cable as the single phase switching of underground networks can result in the inadvertent operation of earth leakage protection systems. Isolators are generally very reliable and require little maintenance.

Gas insulated pole top switches are the current standard for pole mounted three phase switchgear. These switches have a breaking capacity equal to their current rating, typically 400 or 630 ampere and a fault making capability that matches the network fault levels. They can be remotely controlled or manually operated from the ground. These switches are fully sealed and require very little maintenance other than routine inspection.

The installation of both isolators and air break switchgear peaked between 1986 and 1990. This means that on average this type of switchgear is above 30 years old on the network. The installation of air break switches ceased in 2006 with the removal of air break switches from JEN's construction standard. Overhead gas switches are now installed instead of air break switches. Isolators are still deployed as part of standard construction but as most network development these days is underground the rate at which isolators are installed is modest.

The JEN currently has 525 air break switches and 2,203 overhead isolators sets in service.

4.1.9.2 Response

The "JEM AM Electricity Distribution Asset Class Strategy" (ELE AM PL 0060) sets out JEN's plans for the management of this asset class in order to maintain network performance at current levels. It describes that rate at which these installations need to be replaced to maintain the safety and reliability performance of the network.

This strategy plan is informed by the "Overhead Air Break Switchgear Inspection and Test Plan" (JEN PL 0051). This plan sets out the requirements for the inspection and functional testing of air break switchgear and together with the operational CRO (Caution Re Operation) tagging of defective overhead switchgear and the results of the line and pole inspection program, generates the volumes for the replacement program.

Once defective switchgear has been identified the JEN "Air Break Switch Replacement Guideline" (JEN GU 0025) sets out the requirements for the replacement of existing air break switches and isolators and the requirements for the installation of new switching devices. These strategies are to be applied to the:-

- replacement of HV air break switch gear on distribution feeders;
- replacement of other non-standard forms of HV air break switch gear on distribution feeders;
- installation of HV isolators (disconnectors) on distribution feeders; and
- installation of Manual Gas Switches on distribution feeders.

A great deal of work has been undertaken to clear a backlog of air break type switches that have been CRO tagged to ensure these network elements are available and fit for service The section of the Asset Class Strategy (ACS) covering this group of assets indicates that in order to maintain the performance of these assets at current levels then a replacement rate of 23 units per year is required.

4.1.10 Non-Pole Type Substation Switchgear Inspection Program

4.1.10.1 Overview

In the same manner as the HV switchgear on the overhead network is critical to the safe and reliable operation of the network the switchgear incorporated in the various types of indoor or enclosed substations is also critical.

This type of switchgear is more complex and compact than pole mounted equipment and incorporates features that allow the isolation, earthing and testing of the underground networks they are connected to. The insulating mediums used in the switchgear include air, oil, SF6 gas and solid or epoxy insulating systems.

Historically pole top style switchgear and isolators were utilised in some indoor substations and some of these installations are still in service with their attendant problems around size, susceptibility to vermin flashover and damage, operational difficulties and lack of operator safety. Early 22kV substations also used air insulated switchgear and these have proved problematic over time due to their need for high levels of maintenance to maintain their functionality together with the hazards associated with bare 22kV equipment in a confined space.

The availability of compact 22kV Ring Main Unit (RMU) type metal clad switchgear with integrated earth switches and testing facilities allowed the development of compact kiosk type substations and greatly improved the level of operator safety in both kiosk substations and indoor substations. Fully rated fault make, load break switching provided in modern RMU switchgear is now the standard for all enclosed switchgear applications.

JEN has a range of switchgear types installed in its indoor and kiosk substations operating at all distribution voltages. These include:-

- Air insulated single phase isolators and fuse combinations;
- Air insulated three phase load break switches and fuse combinations;
- Oil filled RMU's;
- SF6 insulated RMU's; and
- Oil insulated rotary switchgear configured as RMU's

The population of distribution switchgear as at December 2018 can be characterised as follows:

- 1,656 Ring Main Units; and
- 197 Indoor air break switches.

Of the 1,656 Ring Main Units, 443 units are of an oil immersed rotary type switch which is incorporated into the current Wilson Transformer kiosks.

4.1.10.2 Response

The "JEM AM Electricity Distribution Asset Class Strategy" (ELE AM PL 0060) sets out JEN's plans for the management of this asset class in order to maintain network performance at current levels. It describes that rate at which these installations need to be replaced to maintain the safety and reliability performance of the network. It also details any equipment type issues that need to be addressed as part of the program.

The Asset Class Strategy for this group of assets is informed by the substation inspection program as detailed in the "Enclosed Distribution Substation Inspection Manual" (JEN MA 0695) together with the operational CRO (Caution Re Operation) tagging of defective equipment. These inspection processes and the analysis of fault and defect reports are the main drivers of volumes for the replacement programs.

4.1.11 Thermographic Surveys

4.1.11.1 Overview

Thermographic surveys and corona surveys are powerful condition monitoring techniques that JEN applies to all elements of its distribution network. These are none invasive techniques that allow the condition of various network elements to be assessed under in-service conditions. The strategy that JEN applies to the use of these technologies is set out in the JEN “Thermal Survey Guideline “(JEN GU 0400).

This guideline covers the use of thermal and corona discharge surveying as a condition monitoring tool across JEN and specifically addresses the following areas:

- Zone substations (include all sub-transmission, high voltage apparatus and control room equipment);
- Sub-transmission lines over their entire length;
- High voltage feeders covering the whole backbone of the feeder including all spurs within a 6km radius of the zone substation (include all high voltage apparatus and pole top distribution substations); and
- All non-pole type substations (e.g. kiosk, indoor and ground type in conjunction with the enclosed substation inspection program).

4.1.11.2 Response

This technology allows high impedance connections and overheated network elements to be identified before thermal runaway and failure occurs. The identified hot spots are assessed, prioritised and then rectified which translates to fewer numbers of network faults occurring and the maintenance of network reliability and quality of supply. This is a proactive program that maintains and improves network reliability and safety.

4.1.12 Zone Substation Inspection Program

4.1.12.1 Overview

Zone substations and their associated primary plant and buildings are critical to the security of the JEN. These are the principal interface assets for the entire distribution network and consequently they are designed and configured with an appropriate level of redundancy and maintained accordingly with a comprehensive range of condition monitoring tasks scheduled on a routine basis. The cornerstone of this condition monitoring activity is a suite of inspections that are applied to various sub asset classes. This includes monthly operational inspections, annual engineering audits and three yearly civil audits. The details of all inspection regimes employed by JEN are set out in the “Primary Plant Asset Class Strategy” (ELE AM PL 0061).

4.1.12.2 Response

The results of the inspection regimes applied to zone substations are used to drive the preventative and defect maintenance activities required to maintain network performance in terms of reliability and safety at current levels. The results of these proactive inspections also inform the asset replacement activity in these asset classes.

4.1.13 Asset Routine Maintenance

4.1.13.1 Overview

The maintenance program employed on the JEN Distribution network is critical to the achievement of all network performance targets in the areas of overall network reliability, individual customer reliability (GSL’s), overall network safety and regulatory compliance. The maintenance strategies applied to the various asset classes are set out in the following documents:

- JEN AM Electricity Distribution Asset Class Strategy” (ELE AM PL 0060);
- JEN AM Primary Plant Asset Class Strategy (ELE AM PL 0061);
- JEN AM Secondary Plant Asset Class Strategy (ELE AM PL 0062); and
- JEN AM Measurement Asset Class Strategy (JEN PL 0063).

Detailed maintenance and inspection instructions that result from these strategies are included in a number of documents including the following:-

- JEN Asset Inspection Manual (JEN MA 0500);
- Enclosed Distribution Substation Inspection Manual (JEN MA 0695);
- Various Standard Maintenance Instructions; and
- SAP Maintenance Plans.

JEN uses the PM module of SAP to manage all of its maintenance activities. The results of asset inspections are translated to equipment notifications in SAP that are then prioritised and issued to field crews to action. Maintenance plans that embody the maintenance strategies for each asset class are also held in SAP. These generate maintenance notifications based of a variety of triggers that include time and condition measures such as “sound wood” measurement, operation counters and fault operation points.

4.1.13.2 Response

The computerised maintenance management system (SAP PM) allows tasks to be prioritized and grouped into work packages. It also allows monitoring and tracking of maintenance activity and data capture on equipment condition. Progress against planned maintenance can also be monitored, overdue maintenance activities identified and reprioritised.

In order to optimise field activities and efficiency JEN has developed a guideline entitled “JEN Opportunistic Maintenance Whilst Undertaking Capital and Operational Works” (ELE AM GU 0011). The intent is to take advantage of planned outages to complete maintenance tasks for which open maintenance notifications exist.

4.1.14 Underground Cable Testing and Replacement (ad hoc)

4.1.14.1 Overview

Approximately 30% of the JEN network by network length is comprised of underground cable distribution systems. The population of underground distribution systems can be characterised as follows:-

- Sub-transmission Oil Filled and Paper Cable – 6.90km;
- Sub-transmission XLPE – 10.60km;
- High Voltage XLPE - 635.95km;
- High Voltage Paper - 153.45km; and
- Low Voltage Mains Cable - 1,269.34km.

These assets however only contribute to approximately 7% of all network outages reflecting the intrinsic reliability of this group of assets and the limited impact that the environment has on their reliability performance.

However, there are some known integrity issues associated with some of these types of cables and cable accessories as detailed in the JEN “Electricity Distribution Asset Class Strategy” (ELE AM PL 0060) and it is expected that as this group of assets age, failure rates will increase and thus impact on overall network reliability performance.

Table 4-3 Underground Asset HV Network Outages

Outage cause	2010	2011	2012	2013	2014	2015	2016	2017	2018	Total
Underground cable failure	22	13	20	20	19	10	17	14	18	153
Underground cable dig-in	1	3	3	2	1	1	1	1	1	14
Total all outage causes	308	280	232	306	308	263	293	259	276	2525
% of total outages	7.5%	5.7%	9.9%	7.2%	6.5%	4.2%	6.1%	5.8%	6.9%	6.6%

The condition monitoring of this group of assets is problematic as no simple, efficient condition monitoring technology can be applied without the need to take the equipment out of service. This makes the condition monitoring of this plant difficult to implement and tests to establish cable condition are generally only done opportunistically, at commissioning or when faults have occurred.

This also highlights the importance of the careful design and planning of these assets to ensure they are deployed in a manner that incorporates an appropriate level of redundancy and the ability to isolate and access these assets for testing and repair without impacting network performance.

4.1.14.2 Response

Increasing cable failure rates are forecast for the JEN network as cables, cable joints and accessories age. A range of underground cable tests have been developed to prove the integrity of the cable insulation systems and attached cable accessories.

In the case of 66kV cables proactive sheath testing is performed to ensure the integrity of these critical cables is monitored and maintained.

On the high voltage distribution network a range of electrical tests will be performed when there is a need to prove a cable is suitability for energization (commissioning) or when there is a need to establish the condition of the cable. For example if the cable has suffered a number of faults. These test results will then inform decisions on the need for asset replacement.

On the LV network cable tests are not routinely performed to asses cable condition but rather performed to locate cable faults.

The condition of high voltage and low voltage cables is monitored through the analysis of failures and all cable faults are investigated to determine the cause of failure. The modes of failure primarily include:

- Third party damage; and
- Failure of terminations and joints.

Third party damage is addressed by the pro-active promotion of the ‘Dial Before You Dig’ service (MOCS – Melbourne One Call Service); and thermographic and ultrasonic monitoring of terminations in conjunction with the inspection of enclosed distribution substations is used to help assess the condition of the cable terminations.

Based on historical activity it is anticipated that approximately 1.3km of HV cable and 1.3km of LV underground cable will need to be replaced in the 2021-2025 period to maintain network reliability performance.

4.1.15 Optimisation of Feeder Arrangement at Zone Substations

4.1.15.1 Overview

The “Jemena Planning Manual” (JEM MA 0010) sets out the requirements for the configuration and sectionalisation of high voltage distribution feeders. This includes the layout and configuration of feeder ties with particular reference to their source so that adjacent feeders are fed from different buses or from different zone substations. This ensures a level of redundancy in the feeder network that facilitates:-

- load transfers;
- the isolation of feeder faults;
- the restoration of supply under fault conditions;
- the maintenance of zone substation primary plant such as feeder circuit breakers and buses; and
- the recovery from the outage of major zone substation plant.

These arrangements are critical to the reliability performance of the network.

The manual also addresses customer numbers and loads in feeder switching zones. The management of feeder customer numbers is critical to the reliability performance of the network and the achievement of the associated reliability targets.

When works occur that involve the replacement of zone substations assets, such as switchboards or switchgear, care needs to be taken to ensure that network risk is managed during the construction process. This is of particular importance when normal levels of network redundancy are impacted by construction activity.

The replacement of assets such as switchboards at zone substations or the installation of new zone substations provide an opportunity for the optimisation of feeder arrangements and configurations to ensure network reliability and flexibility is maintained and improved.

4.1.15.2 Response

Prior to the start of major works that impact on network security, redundancy and flexibility such as major asset replacement works at zone substations, all network risk needs to be assessed and mitigated where possible. To ensure the integrity of critical assets and the network generally during the construction phase risk mitigation may include the following:-

- modification of protection schemes or settings;
- thermographic survey of critical infrastructure and components;
- the completion of all outstanding maintenance notifications on critical assets or network elements;
- additional vegetation inspection and clearance;
- engineering audits of critical plant and equipment;
- the deferral of other scheduled works that impact of the effected parts of the network;
- the re-rating of overhead lines;
- the reduction in construction outage times;
- the construction of temporary network elements;
- the staging of feeder re-arrangements or reconfigurations; and
- the preparation of contingency plans.

It is essential that all care is taken when the network is undergoing augmentation or replacement works to ensure that overall network performance is not detrimentally impacted as a result of an outage occurring when normal levels of redundancy and security are unavailable. Particularly in the case where the integrity of the sub transmission network is effected and an outage could result in the loss of tens of thousands of customers.

Zone Substation “BY” – Feeder Layout

Zone substation BY developed historically as a single transformer station with five 22kV feeders. Redundancy for the loss of the transformer or the 22kV bus was provided by feeder ties to surrounding zone substations via remote controlled gas switches on the 22kV feeder network. As the load grew on the station it reached a stage where the cyclic rating of the transformer was exceeded and the ability to transfer the feeders to other zone substations was limited. A second transformer was installed with the associated new second 22kV bus and feeder circuit breakers. The five 22kV feeders however have remained connected to bus No.1. In the event of an outage on this bus there is no mechanism to transfer load via the feeder network to the No.2 22kV bus and the ability to transfer the feeders to adjacent zone substations remains limited.

It is proposed that two of the BY feeders be transferred to the new bus in conjunction with, and leveraging off, a feeder protection replacement program scheduled to occur at Zone Substation “BY” in about 2021. This would standardise the feeder configuration and balance up the loads on the 22kV switchboard across the two buses. This would lower the risk associated with the loss of the No. 1 22kV bus and ensure that security and redundancy of the network at “BY” was consistent with the JEN planning standards. This new feeder arrangement would facilitate the transfer of “BY” feeders from bus No.1 to the new bus No.2 via the feeder network and thus allow for recovery from the loss of a bus at “BY”. This lowers the risk profile for the station and is consistent with the maintenance of the network reliability targets.

As the circuit breakers are available on the No.2 22kV bus and the protection systems are being replaced on the existing feeders then the only additional costs will be those costs associated with the physical relocation of the feeder exit cables.

4.1.16 Distribution Substation Augmentation - Load Related

4.1.16.1 Overview

The organic growth in household loads together with infill development resulting in higher density living in established suburbs means that the network maximum demand (MD) continues to grow. This is despite the amount of imbedded generation installed privately which reduces the networks energy requirements but does not reduce the network MD at times of peak demand. Loads such as pool pumps, air-conditioners, DC chargers and general electronic and electrical house hold items are steadily growing in number and cumulatively increasing the loading demands placed on the electrical network. This results in the overloading of network elements particularly on the low voltage network and can result in the operation of fuses and the failure of some assets such as distribution transformers thus reducing the overall reliability and quality of supply for the customers directly involved.

Emerging technologies such as localised embedded generation with storage capacity have the potential to provide an alternate source of supply at times of MD however, currently solar generation without battery storage makes up the majority of embedded generation connected throughout JEN’s distribution network and there remains periods where this generation does not align with the times of maximum demand. Consequently there remains a need to augment the network to prevent overload and supply interruptions.

JEN has established an annual Distribution Substation Augmentation program to proactively and reactively identify overloads and carry out network upgrades to compensate for the loading demands. This work has been driven reactively in the past by the performance of the network in heat wave conditions. The failure of network assets under heatwave conditions has had a high profile in the media and has drawn criticism from government.

The introduction of smart meters and the increased data sampling rates now being employed is expected to result in better data on network loads and load profiles. This will allow better management of the loading of distribution substations and facilitate the proactive management of overloaded network elements, particularly distribution transformers. It is anticipated that the advancements in load modelling will increase the number of proactively identified overload issues. This will result in an increase in the amount of network augmentations required but should address the reliability, supply quality and safety problems that have occurred periodically in heat wave conditions.

Of the 6,456 distribution substation installed on the JEN network in 2018, 442 were identified as being overloaded by more than 20% of their nameplate rating. The load on 156 of these distribution substations exceeded the transformers nameplate rating by greater than 50%.

4.1.16.2 Response

The planning and design standards applied to modern distribution substations account for the load densities typically found in modern urban residential settings and consequently substations are laid out so as to limit the number of customers connected to each substation. In older established parts of the network however, the increase in customer density due to infill development as well as the increase in average diversified maximum demand (ADMD) per customer has resulted in the overloading of many older transformers. Analysis of distribution substation loading data indicates that as at 2018, 442 transformers are operating with maximum demands in excess of 120% of their nameplate rating. Of these 10kVA, 100kVA, 200kVA and 250kVA transformers which are generally located in older established parts of the distribution area, constitute 48% of all of the transformers on the network that are loaded at or above 120% of their nameplate rating. Further, the analysis indicates that there are 152 transformers operating with maximum demands in excess of 150% of their nameplate rating. At these levels of overload supply quality standards cannot be maintained and transformer life expectancy is significantly reduced.

The Distribution Substation Augmentation Program is designed to proactively identify and augment overload transformer installations prioritised according to the level of overload and their geographic location in the network. The intent is to prevent in service failure of these assets with the associated impact that these failures have on network performance in terms of reliability, GSL's and safety. The prime driver of this program is safety and GSL's as the failure of these assets in service does not greatly impact overall network performance but does result in significant outages for relatively small numbers of customers. These outages often occur during periods of weather extremes and can be accompanied by environmental spills and public safety issues.

The details of the Distribution Substation Augmentation program set out below are based on the targeting of those transformers operating with maximum demands in excess of 150% of their nameplate rating.

Table 4-4 Overloaded Distribution Substations (≥ 150% of Nameplate Rating)

Substation Upgrades	10kVA	16kVA	25kVA	50kVA	100kVA	200kVA	250kVA	300kVA
Total Installed	387	115	343	284	177	406	61	1170
Bushfire Area	62	2	5	3	1	0	0	0
Non-Bushfire Area	0	0	0	3	11	28	1	27
Total	**62**	**2**	**5**	**6**	**12**	**28**	**1**	**27**
Total Percentage	**16.0%**	**1.7%**	**1.5%**	**2.1%**	**6.8%**	**6.9%**	**1.6%**	**2.3%**
Substation Upgrades	**315kVA**	**400kVA**	**500kVA**	**750kVA**	**1MVA**	**1.5MVA**	**2MVA**	**3MVA**
Total Installed	552	35	1823	101	416	186	97	18
Bushfire Area	0	0	0	0	0	0	0	0
Non-Bushfire Area	2	0	6	2	1	1	1	0
Total	**2**	**0**	**6**	**2**	**1**	**1**	**1**	**0**
Total Percentage	**0.4%**	**0.0%**	**0.3%**	**2.0%**	**0.2%**	**0.5%**	**1.0%**	**0.0%**

The extent of all overloads shall be verified prior to scheduling distribution substation augmentation works. The availability of good quality data via the smart meter roll out has and will enabled the transition of this program of works from a reactive one to a proactive one. It has also helped address and manage the crisis that has occurred in heat wave conditions that has historically resulted in large network events involving the in-service failure of substation installations at times of maximum demand.

The scope of works for these distribution substation augmentations will vary from case to case but could involve the following:-

- transformer upgrade;
- transformer upgrade and LV circuit redistribution;
- transformer upgrade with additional LV circuits; and
- new substation installations with associated LV reticulation.

The works will be prioritised in the following order:-

- Overloaded transformers located in the HBRA (principally 10kVA and 16kVA sizes);
- Undersized older transformers located in the older established urban areas (100, 200 and 250kVA sizes); and
- The remainder of the overloaded transformer population (all sizes) prioritized by extent of overload.

HBRA

All pole mounted transformers loaded at or above 150% of nameplate rating and all indoor and kiosk transformers loaded at or above 110% of nameplate rating located in the HBRA shall be targeted for augmentation. The vast majority of these are small capacity pole mounted substations of 10 and 16kVA size. The risk of the in service failure of any overloaded transformer located in the HBRA justifies the prioritization of this program of works.

Table 4-5 Overloaded Distribution Transformers in the HBRA

Substation Upgrades	10kVA	16kVA	25kVA	50kVA	100kVA
Total Installed	385	115	332	297	109
Loaded > 150%, < 300%	62	2	5	3	1
% Number Overloaded	16.10%	1.74%	1.51%	1.01%	0.92%

Table 4-6 HBRA Overloaded Transformer Augmentation Costs

Period	Substation Upgrades (HBRA)	Cost ($2019 ‘000s, direct escalated cost, including overheads)
2021	22	$948
2022	19	$819
2023	16	$690
2024	15	$650
2025	1	$43
2026	0	$0
Total	**73**	**$3,150**

Older Undersized Nonstandard Transformers

The older 100kVA, 200kVA, 250kVA and 400kVA overloaded transformers form the next group of substations to be targeted for upgrade. Based on current demand information 40 pole mounted transformers have been identified as being loaded at or above 150% of nameplate rating and will be targeted for augmentation. These are generally installed in the older established parts of the distribution network and are those transformers that are suffering the largest effects of the infill development occurring in these geographic areas. Customer numbers on these substations are such that often there is less than 1.5kVA of transformer capacity per connected customer. Current planning standards allow for an ADMD of 4.5kVA per customer.

Table 4-7 Non Standard Overloaded Transformer Augmentation Costs

Period	Substation Upgrades (Non Standard Sizes)	Cost ($2019 '000s, direct escalated cost, including overheads)
2021	6	$846
2022	8	$1,128
2023	8	$1,128
2024	8	$1,128
2025	9	$1,269
2026	1	$141
Total	**40**	**$5,641**

Remaining Transformer Sizes

The remaining overloaded substations shall be assessed based on the following criteria:-

- Pole mounted transformers loaded at or above 150% of nameplate rating;
- Indoor and kiosk type transformers rated at or above 110% of nameplate rating.

Table 4-8 Overloaded Transformers (remaining sizes) Augmentation Costs

Period	Substation Upgrades (Remaining Sizes)	Cost ($2019 '000s, direct escalated cost, including overheads)
2021	6	$846
2022	7	$987
2023	8	$1,128
2024	9	$1,269
2025	12	$1,692
2026	21	$2,962
Total	**43**	**$8,884**

Annual Distribution Substation Augmentation Costs

Table 4-9 Total Overloaded Transformer Augmentation Costs

Period	Substation Upgrades (Remaining Sizes)	Cost ($2019 '000s, direct escalated cost, including overheads)
2021	34	$2,640
2022	34	$2,934
2023	32	$2,946
2024	32	$3,044
2025	22	$3,005
2026	22	$3,103
Total	**156**	**$17,672**

4.1.17 Service Neutral Integrity Testing

4.1.17.1 Overview

Energy Safe Victoria requires that all overhead and underground services are inspected and tested on a ten year cycle and that the impedance of the neutral to earth be less than 1 ohm. Historically the testing of neutrals has been carried out using a neutral integrity tester and has required the implementation of an extensive and expensive test program. Neutrals found to fail the test are then actioned and typically this involves service replacement or repair.

4.1.17.2 Response

Advances in metering technology has allowed these neutral integrity tests to be carried out as part of the smart meter functionality. Meter data analytics are being utilised to carry out neutral impedance measurements to provide an ongoing monitoring of all service neutral impedances. There is still a need to carry out on site tests where meter data is not available and to confirm the existence of a problem when one is detected by the meter data analytics. Also site measurements are required for the validation of the ongoing accuracy of the meter data analytics. This involves a crew individually testing a sample of services.

The physical inspection of services is carried out as part of pole and line inspection activity as set out in the “JEN Asset Inspection Manual” (JEN MA 0500).

The intent of this activity is to maintain overall network performance in terms of the safety of the network and of the connected customers installations.

4.2 Control Network Fault Impact

The two pillars that underpin overall network reliability performance can be described as prevention and recovery. Prevention being the activities that are designed to prevent faults occurring on the network (discussed in section 4.1). Recovery being those strategies or actions that are taken to limit the impact of a fault once it has occurred. This is achieved by either limiting the area effected by a fault or reducing the length of the outage time. This section of the network performance plan discusses those strategies intended to reduce the impact of an outage once it has occurred. This primarily addresses the reliability performance of the network and the guaranteed service levels.

JEN’s 360,000 customers are supplied via 222 high voltage feeders. This means the average feeder supplies approximately 1,500 customers. The capacity planning team are forecasting a 2% annual growth in customer numbers over the course of the 2021-2025 period. This equates to approximately 6,500 new network customers each year or the equivalent of 4 new “average” feeders. This growth is occurring in concentrated growth corridors and consequently, based on the networks recent SAIFI and CAIDI performance (SAIFI = 1.0 and CAIDI of 60 minutes), an additional 6,500 customers can be expected to increase network SAIDI by approximately 1.15 minutes per year. To offset this increase in SAIDI caused by the growth in customer numbers further sectionalising of the feeder networks larger feeders is required to maintain overall network performance at current levels.

Dividing a 4,000 customer feeder into two 2,000 customer sections by installing an ACR (or similar intelligent protection device) and a remote controlled switching device will result in an estimated 0.35min SAIDI reduction per year (based on the sustained outage effecting only half of the customers, SAIFI = 1.0 and CAIDI =60min). So to offset the deterioration in reliability performance due to increasing customer numbers it is necessary to install four sectionalising devices (ACR’s or other similar protective devices) and a similar number or remote controlled switches per year to maintain overall network reliability performance at target levels.

4.2.1 Auto Circuit Reclosers (ACR’s)

4.2.1.1 Overview

There are 124 ACR’s deployed on the JEN overhead high voltage distribution network used to sectionalise and automate the 222 distribution feeders. They are self-contained light duty three phase circuit breakers complete with overcurrent, earth fault and sensitive earth fault protections and automatic reclose functionality. They are remote controlled via the network SCADA system and are placed to reduce the impact of network outages by dividing the feeders that have large customer numbers and a history of frequent permanent and transient network faults into smaller sections.

The deployment of ACR's on the overhead part of the JEN network is the biggest single contributor to the improvement in the network reliability performance of the JEN network over the past 10 years. The success of these devices is due to their ability to discriminate with upstream protection devices when connected in series and thus limit the impact of network faults. This includes with other ACR's and feeder circuit breakers located at zone substations. This can be problematic when the devices are located close together where there is little reduction in fault levels and in these circumstances protection blocking schemes have been utilised to ensure correct fault discrimination and isolation. This circumstance is very common on the JEN network which can be characterised as having high load densities with large customer numbers and small geographic distances.

A further complication to the correct discrimination of faults by these devices is the growth in the size of the underground component of the JEN distribution network. This has resulted in significant amounts of cable capacitance connected to zone substation buses resulting in capacitive currents flowing from these cables towards the location of any fault on the source zone substation feeder network. As the length of the underground network increases the magnitude of these capacitive discharge currents gets larger and can exceed the "min-op" settings on the sensitive earth fault protections. As these protections on the range of ACR's deployed are not currently directional then maloperation or "sympathetic tripping" of the ACR's can occur resulting in unnecessary network outages on healthy parts of the network.

Currently there are 18 feeders on the JEN that supply a total of approximately 83,000 customers. Each of these feeders supplies in excess of 4,000 customers. That is 24% of the customer base supplied via 8% of the HV feeders.

4.2.1.2 Response

In order to continue the rollout of ACR's on the JEN high voltage distribution network and to ensure the reliable operation of those ACR's already deployed, the issue of potential "sympathetic tripping" associated with the increasing magnitude of underground cable capacitance needs to be resolved. As the network continues to grow and customer numbers on individual feeders reach the 4,000 customer threshold then ACR's need to be installed where possible to maintain network reliability performance.

Two strategies are proposed to address this issue as follows:-

- All future specifications for ACR's are to include the provision of directional sensitive earth fault protection as well as a requirement for the protection and control systems to be compatible with existing network communication systems and protection blocking schemes.
- The replacement of ACR's that are at risk of "sympathetic tripping" with new ACR's that meet the above requirements or the retrofitting of the protection and control systems on existing ACR's with protection and control systems that meet the above requirements. The practicality and efficiency of retrofitting the protection and control on existing ACR's needs to be assessed.

It is estimated that six at risk ACR's will need to be replaced or retrofitted with modified protection and control systems per year over the course of the 2021–2025 period to maintain network reliability performance at target levels. This investment is required to maintain the existing network reliability performance levels which are at risk of deteriorating due to the impact of "sympathetic tripping".

In addition, based on a 2% growth in customer numbers per year it is estimated that 2 additional ACR's will be required per year over the 2021-2025 period to maintain the network reliability performance at target levels.

4.2.2 Fault Indicators

4.2.2.1 Overview

Fault indicators provide information intended to assist with the location and isolation of faulted equipment. This can greatly assist with the process of recovery from a fault by facilitating the accurate location of a fault and thus contribute to the reduction in outage times and consequently the network SAIDI. There are approximately 221 manual fault indicators located on the overhead high voltage feeder network and approximately 2,000 located on the underground high voltage network. In addition to these numbers there are 40 remote monitoring fault indicators installed on the overhead network and 42 remote monitoring fault indicators located on the underground high voltage network.

The manual fault indicators installed on the underground network are current driven devices and provided that the fault currents exceed the required threshold these are generally reliable and require little maintenance although some varieties do contain long life batteries.

The fault indicators installed on the overhead network are problematic in that there are a number of different types, some fitted with batteries and some without. These have a limited life and ongoing maintenance is required to ensure reliable operation.

4.2.2.2 Response

The various families of manual fault indicators installed on the overhead feeder network will be assessed and replaced where required to assure the reliability of their operation and the achievement of the network reliability targets. Additional sites will be assessed as required to assist with fault location based on feedback from the Control and Dispatch Centre.

4.2.3 Remote Monitoring Fault Indicators

4.2.3.1 Overview

As indicated above there are currently 82 locations where remote monitoring fault indicators have been deployed on both the overhead and underground high voltage networks. These provide immediate indication to the NOC on the location of network faults and can greatly assist with the direction of field staff to fault sites and the rapid restoration of supply to effected customers by reducing the area of a network outage. Based on the information provided by these fault indicators the Control and Dispatch Centre can isolate effected switching zones and restore supply to unaffected parts of the network using the remotely controlled switching devices such as gas switches and ACR's.

Remote monitoring fault indicators are particularly useful when access to network assets is obstructed by geographic features such as freeways or waterways that make physical patrol of the network difficult or slow.

4.2.3.2 Response

It is proposed to install a further 40 remote monitoring SCADA connected fault indicators on the overhead high voltage feeder network in order to maintain network performance at target levels over the 2021–2025 period. In addition to this remote monitoring fault indicators will be installed on the underground high voltage feeder network in conjunction with the installation of remote controlled RMU's (see section 4.2.4)

4.2.4 Remote Controlled RMU

4.2.4.1 Overview

In order to automate the operation of the JEN it is necessary to have controllable switching devices located at appropriate nodes throughout the feeder network. This has been achieved on the overhead network at relatively low cost by deploying ACR's and remote controlled gas switches. The same cannot be said for the underground parts of the JEN high voltage feeder network. On the JEN network most growth in customer numbers is occurring in new residential estates. In these areas long complex underground networks are being established with large customer numbers on the feeders. The ability to remotely sectionalise these feeders is essential to the achievement of JEN's performance targets for customers located in these growth areas.

JEN has fitted remotely controllable switch actuators to existing kiosk substation switchgear in a number of locations. This has been done in order to facilitate the remote control, via the SCADA system, of long lengths of the high voltage underground network. This equipment was adaptable to a range of switchgear types and was not dependent on a particular switchgear manufacturer. There is an ongoing need to continue this program of work however the technology is no longer available and alternative solutions will need to be developed.

Most original equipment manufacturers can offer remote controllable RMU switchgear but this would require the complete replacement of an existing kiosk substation to allow it to be sited at an appropriate switching node in an established network.

4.2.4.2 Response

The lack of a sustainable market for the switch actuator that JEN has deployed to implement remote control of switching devices in its underground high voltage network has resulted in its withdrawal from sale. A watching brief shall be maintained on this technology gap and alternative solutions investigated as they are identified. There is an ongoing need to remotely control the growing parts of the underground network so that customer numbers on distribution feeders can be managed and controlled and JEN's reliability targets and GSL's for this group of customers can be achieved.

During the 2021–2025 period it is proposed to implement remote control of a further 20 RMU's located at appropriate switching nodes in the growth areas of the JEN underground high voltage feeder network.

4.2.5 HV Circuit Breaker – UG Distribution

4.2.5.1 Overview

Although there has been some deployment of remote controlled switching devices in the JEN underground high voltage feeder network there has not been any equipment with functionality similar to an ACR deployed in the underground network. That is, no equipment has been deployed that is capable of interrupting fault current and isolating a faulted switching zone within an underground network. This type of equipment is commercially available and in order to achieve JEN's reliability targets and GSL's for customers supplied from these parts of the network this type of circuit breaker needs to be deployed in conjunction with remote controlled RMU's on the larger, high customer number, underground feeders where customer numbers have reached or exceeded the 4,000 customer threshold. As indicated in section 4.2.1 there are 18 feeders on the network that supply in excess of 4,000 customers and the majority of these are primarily underground feeders.

In order for this type of circuit breaker to function effectively it needs to be compatible with JEN's existing communication, control and protection systems. This includes the requirement for directional sensitive earth fault protection and the protection blocking schemes currently used to facilitate the co-ordination of circuit breakers connected in series in high fault level environments.

4.2.5.2 Response

In order to achieve the JEN performance targets for customers located in the underground growth areas of the network and to offset the effect that a 2% p.a. growth in network customer numbers has on overall network reliability performance it is proposed to install fully rated remote controlled circuit breakers at appropriate switching nodes in 10 locations over the EDPR period. This is to be done in conjunction with the deployment of remote controlled RMU's to sectionalise the underground networks and facilitate the automation of the underground segments of the high voltage distribution network.

4.2.6 Self-Healing Network Capability

4.2.6.1 Overview

The deployment of controllable switch devices, be they automatic such as ACR's or manual such as pole mounted gas switches, across the high voltage feeder network provides the infrastructure required to allow the implementation of a self-healing network capability. This infrastructure together with the information that is available from remotely monitored fault indicators and the information available from zone substation protection systems can be leveraged to facilitate a self-healing network control system. A self-healing network control system is one which is capable of detecting a sustained fault on the network, isolating the faulted section of the network and restoring those parts of the network not directly impacted without the direct intervention of human network controllers. Potentially this can be done in a time frame that would mean that for a large proportion of customers effected by a network outage, that outage would be a momentary outage only.

Much of the JEN network has been divided into major switching zones utilising controllable switching devices already and this infrastructure is largely responsible for the current level of reliability performance. The implementation of a self-healing network control system is needed to maintain these performance levels in the face of increasing physical response times for field crews due to the increasing traffic congestion occurring across the JEN network.

4.2.6.2 Response

JEN is planning for the implementation of a "Fault Location Isolation and Supply Restoration" system over the course of the 2021–2025 EDPR period.

4.2.7 Feeder Load/Customer Optimisation

4.2.7.1 Overview

There is a conflict that occurs as the network grows and customer numbers increase, between the need to maximise the utilisation of network assets and the need to maintain network reliability performance at target levels. This is because a 22kV feeder that feeds predominantly residential development has the capacity to supply 15MVA of load which could represent in the order of 8,000 to 10,000 diversified residential customers. The loss of a feeder with this many customers has significant impact on overall network performance as well as the reliability performance of those directly impacted.

24% or approximately 83,500 of all of JEN's network customers are supplied via 8% or 18 of the high voltage feeders on the network. Each of these feeders has in excess of 4,000 connected network customers. Many of these customers are supplied via the underground network where the level of automatic switching and remote controlled switching capability is low.

4.2.7.2 Response

Planning for network growth therefore needs to be mindful of the requirements for the sectionalisation of high voltage feeders and the provision of appropriate feeder ties using controllable switching devices (as set out in the "Jemena Planning Manual" (JEM MA 0010)) This ensures a level of redundancy is built into the feeder network that is consistent with the achievement of the reliability performance targets.

A balance can be struck between high asset utilisation and the achievement of the reliability targets. The use of automatic sectionalising switchgear and self-healing network technologies means that the utilisation of high value assets such as feeders can be maximised and the risks associated with large customer numbers in terms of reliability performance can be managed.

JEN will continue to invest in the provision of remote controlled and automated switching particularly in the large underground parts of its network in order to ensure that the reliability targets for customers connected to these parts of the network are achieved.

4.2.8 Establish Alternate Supply Route for Medium to Major Spurs

4.2.8.1 Overview

There are a number of parts of the network that have developed in a manner that is not consistent with the aims set out in the Jemena Planning Manual in terms of the network redundancy provided. This manifests itself often in terms of spurs or radial supplies that have no alternate method of supply. Consequently should a fault occur on the high voltage spur the customers supplied via these assets cannot be restored until the effected assets are repaired or replaced. The reasons that these situations exist can be related to the staged development of an area or local geography. Where underground networks are involved repair or replacement can involve very long outage times.

There are a small number of these spurs in the rural areas and a number of low capacity low density underground networks. Generally these situations only involve small customer numbers but when supply is lost extended outages are the norm.

4.2.8.2 Response

JEN shall continue to monitor these situations and opportunistically establish ties to large spurs in conjunction with any further development or load growth in these areas.

4.3 Maintain Power Quality (Compliance)

JEN's long-term strategy for power quality focuses on a few key areas:

- Compliance with power quality standards;
- The monitoring of power quality received by customers;
- The rectification of revealed power quality non-compliances; and
- The monitoring of emerging developments and the conduct of trials of new mitigating technologies.

JEN's "Power Quality Strategic Planning Paper" (ELE PL 0022) sets out in detail the issues and challenges for JEN in the area of power quality on the JEN network.

This section of the network performance plan discusses those issues that impact upon supply quality and the strategies intended to monitor, maintain and rectify power quality issues on the JEN network. This primarily addresses the regulated supply quality parameters of:-

- Steady State Voltages;
- Voltage Variation (Sags and Swells);
- Harmonic Distortion (percentage);
- Voltage Unbalance (Negative Sequence);
- Voltage Fluctuations (Flicker); and
- Transient Overvoltage (Switching Transients)

4.3.1 Supply Quality Monitoring

4.3.1.1 Overview

The monitoring of supply quality is done on a proactive and reactive basis. Power quality is monitored constantly on the high voltage distribution network using a fleet of power quality instruments permanently installed at zone substations and strategically on the ends of selected high voltage feeders.

JEN also responds to enquiries regarding power quality issues from individual customers. All issues raised are individually investigated and analysed to establish whether or not a breach of code has occurred. Issues that are non-compliant are addressed in an appropriate manner to resolve the non-compliance. Issues that are found to be complaint have the result of the analysis recorded for future reference.

The graph below indicates the numbers of quality of supply investigations undertaken per year and the number of these that are verified non compliances. The verified issues generally come under the following headings:-

- Steady State Voltage Variations;
- Network limitations, overload;
- Flickering Volts;
- Harmonics;
- Network events/faults;
- JEN network switching, Transients; and
- Customer internal issue.

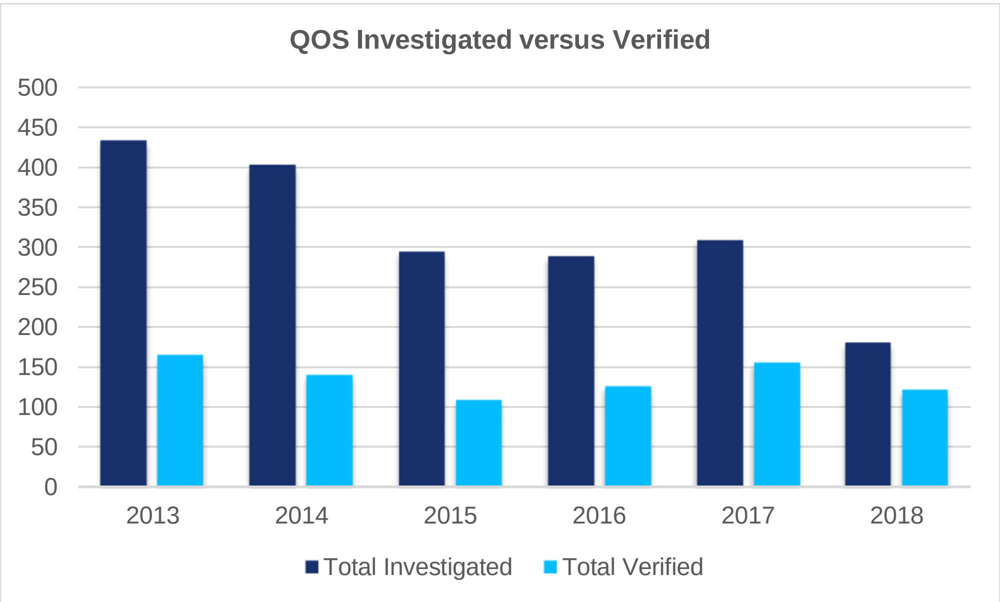

Figure 4-1 Quality of Supply Investigations

The causes of the verified supply quality non compliances can be grouped as follows:-

- Increasing demand, network limitations;
- PV or embedded generation related;
- Disturbing Loads;
- Network disturbance or fault (within the JEN network or external by other DNSP equipment); and

- Environmental

Table 4-10_below sets out the makeup of the verified supply quality investigations by cause. Historically the annual number of verified quality of supply issues has remained fairly constant however, the table indicates a significant increase in the number of issues that are related to compliance with the regulated steady state voltage variations associated with the installation and operation of solar panels (EG systems). This reflects the anticipated impact that the penetration of embedded generation within the LV network will have on supply quality and in particular the regulation of voltage levels on the LV network.

Table 4-10 Verified Quality of Supply Issues

Cause	2013	2014	2015	2016	2017	2018
Low supply voltage	30	29	23	29	20	30
Voltage dips	9	10	6	18	15	20
Voltage swell	1	1	0	2	0	5
Voltage spike (impulsive transient)	1	1	1	1	0	2
Waveform distortion	0	0	0	0	0	1
Solar Related	0	0	19	28	73	89
Other	125	102	61	48	47	27
Total	**166**	**143**	**110**	**126**	**155**	**174**

4.3.1.2 Response

JEN maintains a fleet of permanent supply quality monitoring instruments installed on the high voltage distribution network in all zone substations and at the remote ends of a selection of high voltage feeders. These provide continuous monitoring of supply quality and assist in the identification and analysis of network events as well as monitoring steady state conditions. This fleet of instruments will need to be replaced as they age and budget allowance will be made for their replacement.

In addition to the above power quality (PQ) monitoring equipment JEN maintains a fleet of portable PQ instruments to facilitate the investigation and verification of PQ complaints. This activity requires ongoing resourcing and it is anticipated that the level of activity will increase as the penetration of embedded generation increases.

4.3.2 PV Embedded Generation (EG) systems

4.3.2.1 Overview

There are currently 33,600 EG systems connected to the JEN network. The State Governments Solar Homes Program is forecast to result in the exponential growth in the installation of EG systems with 139,000 EG systems predicted on the JEN network by 2027. In order to export energy the output voltage generated by an EG system has to be higher than the grid voltage at the Point of Supply (POS). Consequently, when a number of EG systems are clustered close together excessive voltage rise can occur in some circumstances leading to exceedance of the Victorian Electricity Distribution Codes (VEDC) “Quality of Supply Steady State Voltage Variation limits”. At a local level this voltage rise can exceed the operating range of the EG system inverter resulting in the shutting down of the EG system. This exceedance of the “Steady State Voltage Variation Limits” also adversely effects the supply quality for neighbouring properties or customers.

Since 2015 JEN has been recording the number of verified supply quality complaints that it receives that are related to the installation and operation of EG systems. Figure 4-2 indicates the number of EG installations installed on the network over the past 4 years.

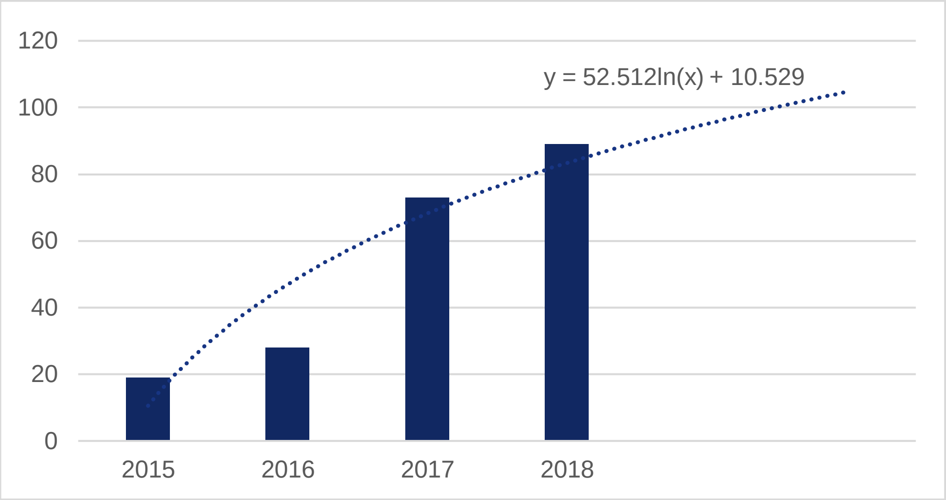

Figure 4-3 EG Related supply Quality Complaints, indicates the rate of growth in verified supply quality complaints that are associated with these installations. It can be seen that there has been a significant increase in the number of supply quality issues associated with these installations. It is forecast that the number of verified voltage complaints associated with the installation and operation of EG systems will also grow exponentially in conjunction with the forecast growth in the numbers of EG systems connected to the network.

Available data indicates complaints are being received at a rate of 0.3% of the number of EG system installations on the network. On this basis then by 2027 the annual number of verified complaints would be in the order of 400 per year.

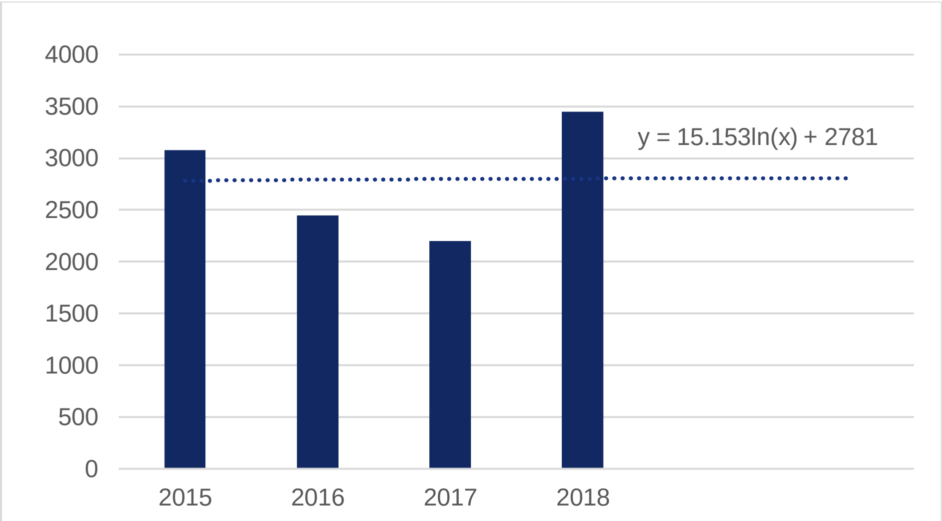

Figure 4-2 EG Installations

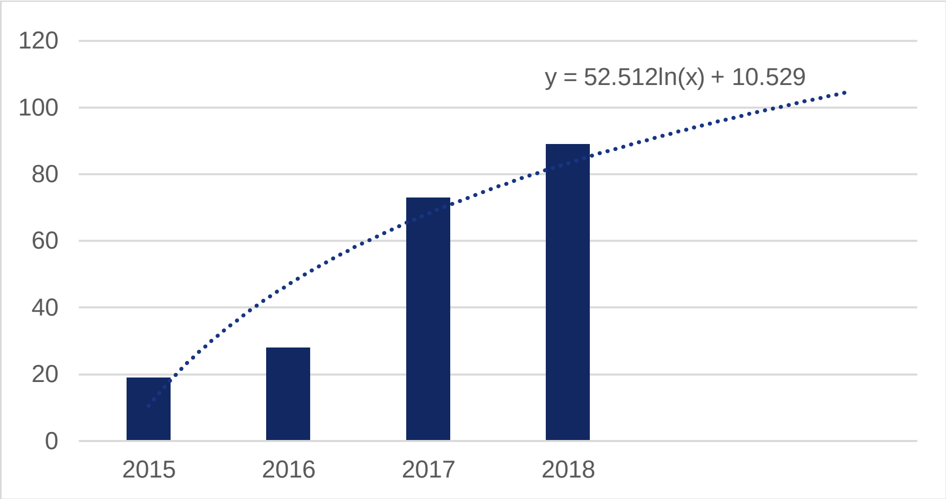

Figure 4-3 EG Related supply Quality Complaints

The installation of EG systems in distribution networks that have predominantly been designed to combat voltage drop problems is problematic and means that at times non-compliance's with the regulated Quality of Supply parameters set within the VEDC will occur. Some of the issues that arise are briefly discussed below.

Circuit Balance

As the installation of EG systems are customer initiated their locations are inherently random in nature and scattered throughout the networks LV reticulation. The scatter effect can result in circuit imbalance as the energy flow becomes bidirectional from the EG source/s. The circuit imbalance can cause voltage shift across the three phases, resulting in high and low voltages across the phases. The imbalance can also result in excessive neutral currents; placing strain on components throughout the neutral circuits.

Steady State Voltage Limits:

The JEN network has been historically designed to cater for voltage drop and consequently the taps on transformers and the voltage levels on the corresponding high voltage feeder network have been set and circuits designed with their maximum voltage at the upper limits, 254.4V initially then 253V. The introduction of EG systems and the resultant voltage rise issues means that there is a need to allow for a 2% voltage rise, meaning that the network steady state voltage needs to be lowered by a minimum of 2% to accommodate the voltage rise caused by the EG systems. In some cases lowering the network set voltage will result in voltage levels below acceptable levels in some areas of the distribution network.

Harmonics

As the capacity of roof top PV generation grows and more energy is injected into the distribution network using Direct Current (DC) to Alternating Current (AC) electronic inverters a watching brief is required on the harmonic levels across the whole network.

Capacity

Care needs to be taken to ensure that the capacity of individual or collectively connected EG installations does not exceed the capacity of network elements such as distribution transformers. This is particularly a risk with small single phase transformers supplying rural properties located within the HBRA.

4.3.2.2 Response

Each identified and verified non-compliance has to be individually analysed and a solution developed to resolve the non-compliance. The network solutions implemented may involve activities such as equipment upgrades, network reconfiguration, circuit balancing, voltage adjustments, and potentially new technologies that involve dynamic control between the network and the customers “Point of Common Coupling”.

In order to address and manage the growing body of work required to ensure network compliance some of the following activities will be required:-

- The proactive monitoring of network voltages at the customer level, identifying areas at risk of non-compliance and modifying the network as appropriate;
- Identifying all transformers at risk of EG overload by comparing transformers ratings to installed EG capacity and upgrade the network as required;
- Comparing individual circuit ratings with the installed EG capacity and upgrading the network as required;
- Identifying dense pockets of EG capacity and upgrading the network as required; and
- Reactively identifying Quality of Supply non-compliance and resolving as appropriate.

Connection agreements may need to be reviewed to ensure network capacity is adequate prior to agreeing to the connection of EG systems.

The increasing penetration of EG systems and the associated expected exponential growth in the verified number of supply quality non-compliances will mean increasing pressure on the budgets available to rectify supply quality non-compliance. This means increased investment to maintain the current levels of network performance and compliance.

To address the issues associated with the concentration of EG systems and the effects that this has on Quality of Supply (QOS) steady state voltages “voltage optimised transformers” (VOT) are currently being trialled. These are designed to address steady state voltage non compliances that have developed as a result of the increased penetration of grid connected photovoltaic (PV) installations. A VOT is used to automatically adjust the network voltage so that it remains within limits, this is achieved by adjusting the output voltage via the inbuilt on load tap changer. There are a number of issues to be assessed including the maintenance needs of these types of technologies before this technology will be deployed as standard equipment on the distribution network.

4.3.3 Harmonics

4.3.3.1 Overview

Non-linear loads, such as DC to AC power converters, computers, power supplies, dimmer switches, light weight transformers, DC chargers (Electric Cars) and arc furnaces all have the ability to generate harmonics. Cumulatively these loads can result in an increase in the base levels of harmonic distortion of the voltage wave shape present on the network; both the HV and LV distribution networks. This can lead to situations where the level of harmonic distortion of the voltage wave shape exceeds the regulated limits.

4.3.3.2 Response

Each identified harmonic non-compliance has to be individually analysed and a solution developed to resolve the non-compliance. Network solutions implemented may involve equipment upgrades, the use of specialised “K” factor transformers designed to prevent overheating caused by high levels of harmonic distortion and the installation of harmonic filtering. Individual customer loads also need to be Code compliant in this regard.

Harmonic distortion is an area where JEN needs to maintain a watching brief and analyse the impact that customers equipment has on the network overall base harmonic levels. To this end JEN will:-

- Continue to monitor and trend the harmonic levels on the High Voltage network; and
- Reactively identify occurrences of harmonic non-compliance and resolve as appropriate.

4.3.4 Distribution Substation Augmentation (PQ Related)

4.3.4.1 Overview

The augmentation of distribution substations has two main drivers:-

- load growth, resulting in plant ratings being exceeded and covered in section 4.1.16; and
- supply quality, generally related to network impedance.

This activity is intended to rectify verified supply quality issues by making budget available for the works necessary to ensure the network remains compliant in terms of the regulated quality of supply measures. Generally supply quality issues manifest themselves when the network impedance is elevated. Typically when long LV distribution circuits are involved. The problems can occur at both ends. Close to the source, the distribution transformer, problems are experienced with steady state voltages exceeding the upper limits. This is magnified by the installation of EG systems that further increase steady state voltages. At the other end of the LV circuit the problem is the opposite with steady state voltages falling below the lower limits.

As customers electrical equipment becomes more complex technically, its impact on network performance grows. In addition its reliance on network performance also grows in terms of the networks compliance with the regulated Victorian Electricity Distribution Code requirements (VEDC) that relate to quality of supply. The overall performance of the network and its interaction with customers equipment is of increasing importance and reduced quality of supply can have a perceived and/or real impact on the operation and lifecycle of connected electrical equipment. Ensuring the distribution network responds to these increasing demands and continues to remain compliant mandates an equally dynamic response and a range of network solutions to the various problems.

4.3.4.2 Response

The solutions to many of the different verified quality of supply issues are often very similar and generally involve increasing network capacity and reducing network impedance. To that end typical solutions may involve some or a number of the following works:-

- Installation of new distribution substations;
- Upgrade of substation capacity;
- Reconductoring of lines;
- Balancing of customer loads;
- Adjustment of voltage levels;
- Splitting of LV circuits; and
- Additional LV circuits.

It is anticipated that network augmentation activity to address quality of supply issues will increase primarily due to the increasing rate of installation of EG systems and their impact on steady state voltage levels. It is anticipated that substation augmentation will continue at historical levels. In addition, approximately 45 minor works tasks per year are historically performed and this is expected to increase to 100 minor works task per year by the end of the period. Details of the proposed budget are included in section 5

4.3.5 Electric Vehicles

JEN is continuing to actively monitor developments in the electric vehicle area as well as the take up of other battery storage technologies. At current levels of take up these technologies have no visibility from a network performance perspective however if and when they are adopted on a large scale they will have a significant impact from both a network capacity and network performance (supply quality) perspective.

5. Proposed Capex and Opex to Maintain Network Integrity and Reliability

5.1 Capital Forecast

The following tables set out the work volumes and associated capital expenditure required to achieve the desired levels of network performance with respect to:

- Network reliability;
- Supply Quality;
- Customer Service Levels;
- Safety;
- Asset Condition; and
- Regulatory Compliance.

Complete set of work volumes for each asset class that covers full lifecycle management of assets is covered in respective Asset Class Strategies.

5.1.1 Network Performance Capex Volumes

The table below sets out the activities by volume included in this plan.

Table 5-1 Network Performance Capex Volumes

Service Code	Description	NPP Reference	CY21	CY22	CY23	CY24	CY25	Total
RHE	Gas Insulated RMU Replacement - No Gas Pressure Indicator and Indoor Switchgear replacement (age and fault)	4.1.2.1 & 4.1.10	6	6	6	6	3	27
RHE	F&G RMU Replacement	4.1.2.2	3	.	.	.	.	3
RUA	HV Cabus Termination Replacement	4.1.2.4	6	6	6	6	6	30
PDS	Bird and Animal Strikes - Approx 50 per year	4.1.3	18	18	18	18	18	90
RXH	Pole Top Fire Mitigation - 66kV ST (xarms)	4.1.4	30	30	30	30	30	150
RXH	Pole Top Fire Mitigation - 22kV ST (xarms)	4.1.4	20	20	20	20	20	100
RXH	Pole Top Fire Mitigation - 22kV Dist (xarms)	4.1.4	410	410	410	410	410	2050
ROH	HV Conductor Replacement - HBRA (kM)	4.1.5	.	.	3	4	.	7
ROL	LV Conductor Removal - HBRA (kM)	4.1.5	4	4	4	4	4	20
ROL	Electric Line Clearance Solutions (Project Base)	4.1.6	2	2	2	2	2	10
PDL	LV Spreaders	4.1.7	12	12	12	12	12	60

Service Code	Description	NPP Reference	CY21	CY22	CY23	CY24	CY25	Total
PDH	HV Spreaders	4.1.7	12	12	12	12	12	60
RUA	HV Cable Replacement - condition (metres)	4.1.14	1228	1,228	1,223	1,239	1,233	6151
RUC	LV Cable Relacement - condition (metres)	4.1.14	363	363	365	365	365	1821
RUA	Sub 'BY' Feeder exit rearrangement (project)	4.1.15	1	-	-	-	-	1
DSJ	Overloaded Transformers - HBRA	4.1.16	22	19	16	15	1	73
DSJ	Overloaded Transformers - Older Non Standard sizes LBRA	4.1.16	7	8	8	8	9	40
DSJ	Overloaded Transformers - Remaining sizes	4.1.16	7	7	8	9	12	43
RMF	Service Cable Faults - Neutral integrity and all faults	4.1.17	604	604	606	607	606	3027
PRA	Distribution system automation - ACR's	4.2.1	2	2	2	2	2	10
RHH	ACR directional E/F retrofit	4.2.1	4	6	6	7	7	30
PRA	Fault Indicator replacement	4.2.2	50	50	50	50	50	250
PRA	Remote monitoring Fault Indicators O/H	4.2.3	7	7	7	7	7	35
PRA	Install Remote Controlled RMU and fault indicators	4.2.4	4	4	4	4	4	20
PRA	Install Remote Controlled CB's and fault indicators (HV UG)	4.2.5	2	2	2	2	2	10
PQA	Distribution Substation Augmentation - Supply Qality Minor	4.3.4	40	70	70	80	80	340
PQA	Distribution Substation Augmentation - Supply Quality - (new or upgraded substations)	4.3.4	5	5	5	5	5	25

5.1.2 Network Performance Capital Costs

The following Table 5-2 sets out the cost of the works proposed to maintain the network performance at target levels. These are direct escalated costs including overheads. Complete set of capital expenditure for each asset class that covers full lifecycle management of assets is covered in respective Asset Class Strategies.

Table 5-2 Network Performance Capex Costs ($2019, direct escalated costs including overheads)

Service Code	Description	NPP Ref.	Forecast Capital Expenditure ($2019 '000s, direct escalated cost, including overheads)						Comment
			CY21	CY22	CY23	CY24	CY25	Total	
RHE	Gas Insulated RMU Replacement - No Gas Pressure Indicator and Indoor Switchgear replacement (age and fault)	4.1.2.1 & 4.1.10	$240	$239	$242	$247	$124	$1,091	Included in ACS Capex
RHE	F&G RMU Replacement	4.1.2.2	$120	$0	$0	$0	$0	$120	Included in ACS Capex
RUA	HV Cabus Termination Replacement	4.1.2.4	$271	$270	$273	$279	$280	$1,374	Included in ACS Capex
PDS	Bird and Animal Strikes - Approx 50 per year	4.1.3	$34	$34	$35	$35	$36	$174	Included in ACS Capex
RXH	Pole Top Fire Mitigation - 66kV ST (xarms)	4.1.4	$228	$228	$228	$228	$228	$1,140	Included in ACS Capex
RXH	Pole Top Fire Mitigation - 22kV ST (xarms)	4.1.4	$83	$83	$83	$83	$83	$413	Included in ACS Capex
RXH	Pole Top Fire Mitigation - 22kV Dist (xarms)	4.1.4	$1,566	$1,559	$1,588	$1,636	$1,652	$8,001	Included in ACS Capex

Service Code	Description	NPP Ref.	Forecast Capital Expenditure ($2019 '000s, direct escalated cost, including overheads)						Comment
			CY21	CY22	CY23	CY24	CY25	Total	
ROH	HV Conductor Replacement - HBRA (kM)	4.1.5	$0	$0	$487	$500	$0	$987	Included in ACS Capex
ROL	LV Conductor Removal - HBRA (kM)	4.1.5	$1,136	$1,132	$1,149	$1,178	$1,187	$5,783	Included in ACS Capex
ROL	Electric Line Clearance Solutions (Project Base)	4.1.6	$306	$305	$310	$317	$320	$1,558	Included in ACS Capex
PDL	LV Spreaders	4.1.7	$6	$6	$6	$6	$6	$30	Included in ACS Capex
PDH	HV Spreaders	4.1.7	$33	$33	$33	$34	$35	$168	Included in ACS Capex
RUA	HV Cable Replacement - condition (metres)	4.1.14	$1,010	$1,004	$1,016	$1,048	$1,053	$5,130	Included in ACS Capex
RUC	LV Cable Relacement - condition (metres)	4.1.14	$242	$240	$244	$251	$252	$1,229	Included in ACS Capex
RUA	Sub 'BY' Feeder exit rearrangement (project)	4.1.15	$200	$0	$0	$0	$0	$200	
DSJ	Overloaded Transformers - HBRA	4.1.16	$948	$819	$690	$647	$43	$3,146	
DSJ	Overloaded Transformers - Older Non Standard sizes LBRA	4.1.16	$987	$1,128	$1,128	$1,128	$1,269	$5,641	
DSJ	Overloaded Transformers - Remaining sizes	4.1.16	$991	$965	$1,134	$1,246	$1,728	$6,063	
RMF	Service Cable Faults - Neutral integrity and all faults	4.1.17	$531	$530	$540	$558	$564	$2,723	Included in ACS Capex
PRA	Distribution system automation - ACR's	4.2.1	$128	$128	$128	$128	$128	$640	
RHH	ACR directional E/F retrofit	4.2.1	$160	$240	$240	$280	$280	$1,200	Included in ACS Capex
PRA	Fault Indicator replacement	4.2.2	$91	$91	$91	$91	$91	$455	
PRA	Remote monitoring Fault Indicators O/H	4.2.3	$26	$26	$26	$26	$26	$131	
PRA	Install Remote Controlled RMU and fault indicators	4.2.4	$248	$248	$248	$248	$248	$1,240	
PRA	Install Remote Controlled CB's and fault indicators (HV UG)	4.2.5	$119	$116	$124	$138	$142	$638	
PQA	Distribution Substation Augmentation - Supply Qality Minor	4.3.4	$100	$172	$183	$203	$209	$866	
PQA	Distribution Substation Augmentation - Supply Quality - (new or upgraded substations)	4.3.4	$630	$630	$630	$630	$630	$3,149	
	Total		**$10,434**	**$10,225**	**$10,855**	**$11,165**	**$10,612**	**$53,290**	

5.1.3 Network Performance Operational Costs

The operational expenditure that supports the performance of the network is included in a range of activities. These are detailed in the various Asset Class Strategies and quantified in the Capital and Operating Work Plans (COWP). Collectively the various asset inspections and condition monitoring activities form the basis for works that underpin the performance of the network in all areas. They are not categorised purely as network performance activities but rather contribute to and drive that range of maintenance and replacement activities that underpin the performance of the network in terms of:

- Reliability;
- Safety;
- Supply quality;
- Customer service levels;
- Asset condition; and

- Regulatory compliance.

The only operating expenditure that is specific to network performance is that that is required to monitor and investigate supply quality issues (Voltage complaints) and is detailed in the COWP.

6. References

- JEN AM Asset Management Plan 2019-2025 (ELE PL 0004)
- JEN AM Electricity Distribution Asset Class Strategy (ELE AM PL 0060)
- JEN AM Primary Plant Asset Class Strategy (ELE AM PL 0061)
- JEN AM Secondary Plant Asset Class Strategy (ELE AM PL 0062)
- JEN AM Measurement Asset Class Strategy (JEN PL 0063)
- Jemena Planning Manual (JEM MA 0010)
- Overhead Air Break Switchgear Inspection and Test Plan (JEN PL 0051)
- Air Break Switch Replacement Guideline (JEN GU 0025)
- Charter for the Asset Performance Review Committee
- JEN Asset Inspection Manual (JEN MA 0500)
- Enclosed Distribution Substation Inspection Manual (JEN MA 0695)
- Thermal Survey Guideline (JEN GU 0400)
- Power Quality Strategic Planning Paper (ELE PL 0022)
- Victorian Electricity Distribution Code