Jemena Electricity Networks (Vic) Ltd

2016-20 Electricity Distribution Price Review Regulatory Proposal

Revocation and substitution submission

Attachment 7-14 Revised Flemington network development strategy

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Flemington Zone Substation

Network Development Strategy

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EXECUTIVE SUMMARY

This report identifies the preferred option for addressing the Flemington Zone Substation (FT) capacity constraint as upgrading the 11 kV transformer cables and switchboards, and installing a third 11 kV switchboard, in the existing switch-room building, as the most prudent and efficient investment in the long term interests to consumers.

The report presents the FT supply capacity risk and outlines how this risk has been quantified. It outlines possible options for economically mitigating supply risks, and identifies the preferred option to manage the forecast supply risk in the area.

This third revision of the Flemington Zone Substation Network Development Strategy incorporates:

- Jemena Electricity Network's (JEN's) 2015 load demand forecasts;
- Detailed analysis undertaken as part of Stage 1 of the Regulatory Investment Test for Distribution (RIT-D);
- Assessment of additional network development options, including non-network options; and
- Preliminary design work and site investigations that have been undertaken since the March 2015 version of this Network Development Strategy was approved.

Augmentation Need

FT is supplied by two 66 kV lines from West Melbourne Terminal Station (WMTS), and consists of two 66/11 kV 20/30 MVA transformers, two 11 kV buses and ten 11 kV feeders. It supplies close to 15,000 domestic, commercial and industrial customers in the Flemington, Kensington, Ascot Vale and surrounding areas, with major customers including Flemington Race Course and the Royal Melbourne Showgrounds.

Based on JEN's 2015 Load Demand Forecasts Report, the:

- 50% probability of exceedence (POE) summer maximum demand is forecast to increase from 34.2 MVA in 2015/16 to 36.9 MVA in 2020/21.
- 10% POE summer maximum demand is forecast to increase from 37.2 MVA in 2015/16 to 40.4 MVA in 2020/21.

The key drivers for investment are:

- The thermal capacity of the zone substation 11 kV assets (30.5 MVA under system normal conditions and 23.9 MVA under N-1 conditions), which prevent full utilisation of the existing 66/11 kV transformers; and
- The connection capacity of the existing two 11 kV switchboards, on which all circuit breakers are already fully utilised, thereby not allowing the connection of additional 11 kV feeders to supply the growing FT demand.

The primary driver for augmentation is the thermal capacity of the zone substation 11 kV assets. The need to replace deteriorating assets, primarily the 11 kV switchboards, is secondary and inconsequential when assessing the economic value of this constraint.

This revised Network Development Strategy includes an assessment of additional potential options, and demonstrates that upgrading only the 11 kV transformer cables, or the 11 kV transformer cables and transformer circuit breakers, provides negative net market benefits. Alternatively, upgrading the 11 kV transformer cables and 11 kV switchboards in the existing switch-room building, with installation of a third 11 kV switchboard, is the preferred option with net market benefits estimated at $180.51 million.

Table ES–1: Summary of options assessed

Augmentation option	2016-2020 project cost ($m)	NPV of net market benefit ($m)	Project ranking
Option 1b - Upgrade 11 kV transformer cables and 11 kV switchboards and install a third 11 kV switchboard (in existing switch-room building)	5.39	180.51	1
Option 6 - Upgrade 11 kV transformer cables (in existing switch-room building)	0.92	(6.85)	8
Option 7 - Upgrade 11 kV transformer cables and 11 kV transformer circuit breakers (in existing switch-room building)	1.18	(7.08)	9

Updated Options Analysis

Since approval of this Network Development Strategy in March 2015, we have undertaken preliminary design work to firm up the feasibility and deliverability of options, including upgrade of the existing 11 kV transformer cables in the existing cable ducts. This design work has given us confidence that upgrading the existing 11 kV transformer cables in the existing cable ducts is likely to be possible, although potential deliverability risks still exist.

The load transfer capacity from FT to neighbouring zone substations Essendon (ES) and North Essendon (NS), via connecting feeders, has been accounted for in our revised assessment of options. While load transfers can offload much of the expected unserved energy under emergency outage conditions, these load transfers cannot be utilised to offload the system normal expected unserved energy due to the additional risk it puts on adjacent feeders, zone substations and sub-transmission lines, in conjunction with its impact on our ability to maintain and operate the network in a secure manner. This load transfer capacity provides only marginal additional benefits because the majority of the expected unserved energy is due to the system normal limitations.

Revised Preferred Option

This report identifies Option 1b as the preferred option because it meets the identified need and maximises the net market benefit compared to all other considered options. To meet the growing demand and to ensure the safety and security of supply to our customers, Option 1b is planned for commissioning by November 2017, and involves upgrading the 11 kV transformer cables and 11 kV switchboards in the existing switch-room building, with installation of a third 11 kV switchboard.

From a capacity improvement perspective this is the same option that was proposed in the previously approved March 2015 version of this Network Development Strategy. However, following our preliminary design work we have gained further confidence that these capacity improvement works can likely be completed within the existing switch-room building by utilising the existing 11 kV transformer cable ducts. This amended delivery approach results in a revised capital expenditure proposal of $5.39 million (real, $2015 direct un-escalated).

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GLOSSARY

Amperes (A)	Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps.
Constraint	Refers to a constraint on network power transfers that affects customer service.
Continuous rating	The permissible maximum demand to which a conductor or cable may be loaded on a continuous basis.
Jemena Electricity Networks (JEN)	One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 320,000 customers via an 11,000 kilometre distribution system covering north-west greater Melbourne.
Maximum demand (MD)	The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
Megavolt ampere (MVA)	Refers to a unit of measurement for the apparent power in an electrical circuit. Also million volt-amperes.
Network	Refers to the physical assets required to transfer electricity to customers.
Network augmentation	An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand.
Network capacity	Refers to the network's ability to transfer electricity to customers.
Probability of exceedance (POE)	The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year:
Regulatory Investment Test for Distribution (RIT-D)	A test established and amended by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments over a certain limit ($5m), in the National Electricity Market (NEM).
Reliability of supply	The measure of the ability of the distribution system to provide supply to customers.
System normal	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices.
10% POE condition (summer)	Refers to an average daily ambient temperature of 32.9ºC derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC.
50% POE condition (summer)	Refers to an average daily ambient temperature of 29.4ºC derived by NIEIR and adopted by JEN, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC.
50% POE and 10% POE condition (winter)	50% POE and 10% POE condition (winter) are treated the same, referring to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC.

ABBREVIATIONS

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
JEN	Jemena Electricity Network
ES	Essendon Zone Substation
FE	Footscray East Zone Substation
FT	Flemington Zone Substation
MD	Maximum Demand
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
NS	North Essendon Zone Substation
POE	Probability of Exceedance
RIT-D	Regulatory Investment Test for Distribution
VCR	Value of Customer Reliability
WMTS	West Melbourne Terminal Station

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1. INTRODUCTION

This section outlines the purpose of the Flemington Zone Substation Network Development Strategy, provides an overview of the Flemington supply area, describes the general arrangement of Flemington Zone Substation (FT), and gives a brief overview of the network limitations.

The assessment is based on the 2015 Load Demand Forecasts Report.

1.1 BACKGROUND

Jemena is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The Jemena Electricity Networks (JEN) service area covers 950 square kilometres of northwest greater Melbourne and includes the Melbourne International Airport, which is located at the approximate physical centre of the network, and some major transport routes. The network comprises over 6,000[1] kilometres of electricity distribution lines and cables, delivering approximately 4,400 GWh of energy to over 320,000 homes and businesses for a number of energy retailers. The network service area ranges from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east.

FT, is supplied by two 66 kV lines from West Melbourne Terminal Station (WMTS). FT consists of two 66/11 kV 20/30 MVA transformers, two 11 kV buses and ten 11 kV feeders. It supplies close to 15,000 domestic, commercial and industrial customers in the Flemington, Kensington, Ascot Vale and surrounding areas, with major customers including Flemington Race Course and the Melbourne Showgrounds.

The 11 kV network supplied by FT is islanded from the surrounding networks to the west, south and east, which operate at 6.6 kV and 22 kV. FT makes up part of an 11 kV network with North Essendon Zone Substation (NS) and Essendon Zone Substation (ES) to the north and north-east of FT. Although some load transfer to NS and ES may be possible during network outage conditions, the load transfer capacity is minimal due to the heavy loading already existing on these surrounding stations and their feeders.

FT is a two-level indoor zone substation that was originally commissioned in around 1970. The top level houses the 66 kV air insulated switchgear, which is insulator suspended from the ceiling of the indoor building. The ground level houses the two 11 kV switchboards and the 66/11 kV transformers.

The primary driver limiting the station's capacity, during summer and winter peak demand periods, is the 11 kV buses, transformer circuit breakers and cables. The full capacity of the two existing transformers cannot be fully utilised under system normal or network outage conditions. Some of the FT feeders, particularly those supplying the central, north and north-west areas of the zone substation supply area, are already heavily loaded, with some close to 100% utilisation. While the average utilisation across all feeders is forecast to be approximately 69% in 2016, the lighter loaded feeders don't supply areas near the heavier loaded areas, and can't be used to offload the heavily loaded feeders. There is also limited capability to connect new feeders at FT due to the rating of the existing 11 kV buses and the full utilisation of 11 kV circuit breakers.

Based on JEN's 2015 Load Demand Forecasts Report, the:

- 50% probability of exceedence (POE) summer maximum demand is forecast to increase from 34.2 MVA in 2015/16 to 36.9 MVA in 2020/21.

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[1] Does not include low voltage services

- 10% POE summer maximum demand is forecast to grow from 37.2 MVA in 2015/16 to 40.4 MVA in 2020/21.

1.2 PLANNED AND COMMITTED AUGMENTATIONS

This section outlines planned and committed works that are currently underway to ensure that loading on the WMTS connection asset transformers doesn't limit the supply capacity to FT. It also outlines feeder line works that are planned to increase load transfer capacity from FT to ES, for supply backup following outage of an FT asset.

1.2.1 WEST MELBOURNE TERMINAL STATION CAPACITY

AusNet Services is currently commencing a rebuild of WMTS. This rebuild includes replacement of the four existing 150 MVA connection asset transformers with three 225 MVA transformers. Following the rebuild the N-1 rating will remain at 450 MVA.

The WMTS rebuild is being undertaken as a separate project to any of the options identified in this development plan, and is expected to be completed by 2019.

1.2.2 11 KV FEEDER WORKS

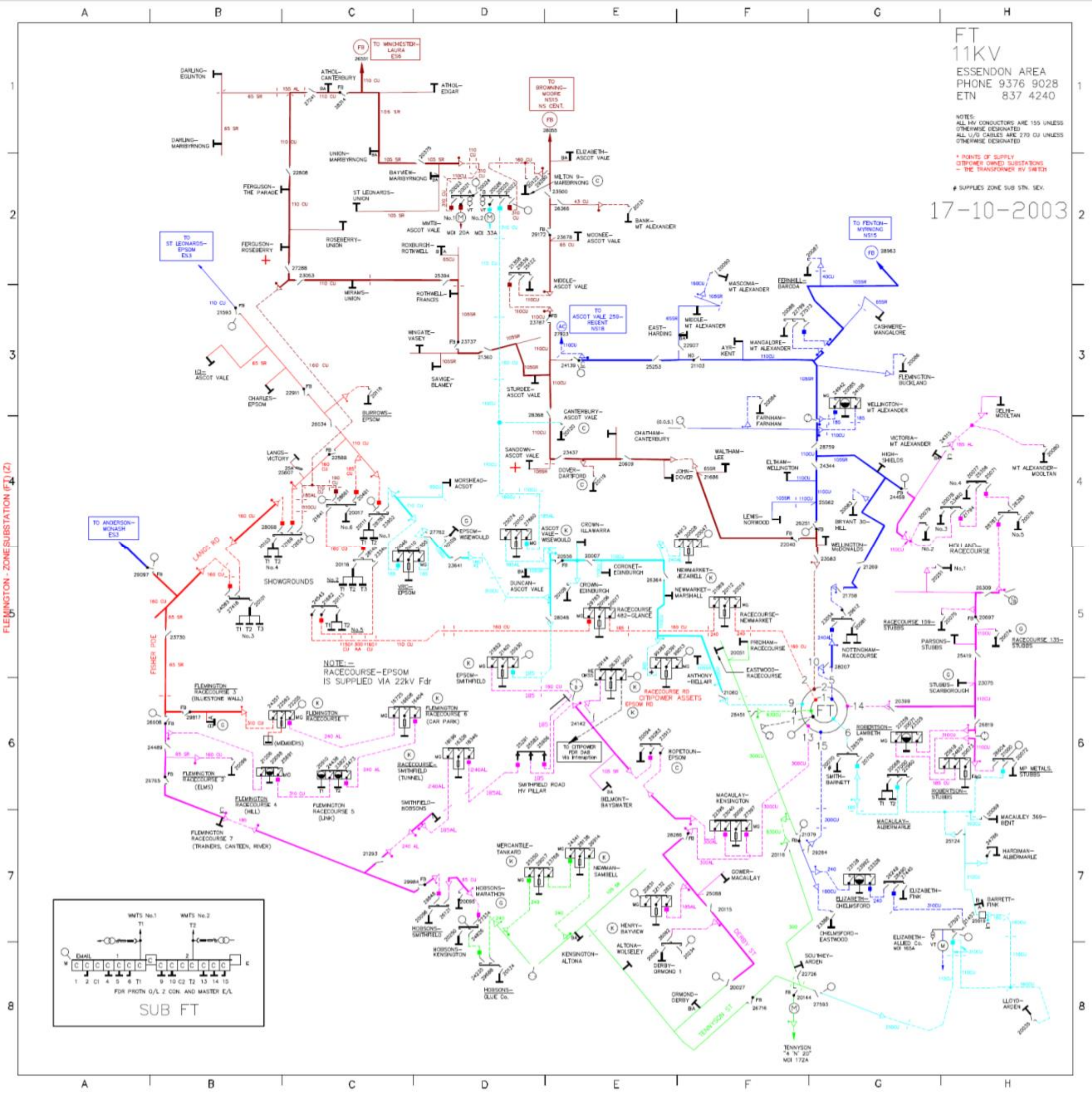
JEN is nearing completion of a project titled Flemington Zone Substation Short Term Contingency Plan, which includes reconfiguring the FT No.1 11 kV feeder line, FT-01, and constructing a new 11 kV feeder from Essendon Zone Substation (ES), to be named ES-22. The new feeder installation and feeder reconfiguration works will provide approximately 6 MVA of additional transfer capacity during a single contingency event, which prior to implementation of a long term thermal capacity solution, can be used to reinstate some supply to FT following a network outage.

The 11 kV feeder work is being undertaken as a separate project to any of the options identified in this development plan, and is expected to be completed in December 2015.

1.3 GENERAL ARRANGEMENT

Figure 1–1 shows the supply area arrangement of the ten 11 kV feeders supplied from FT. It provides an indication of the area each of the FT feeders supply and where they connect with the surrounding zone substations ES and NS via their feeders.

Figure 1–1: Flemington supply area arrangement (15 December 2015)



2. IDENTIFIED NEED

Flemington Zone Substation (FT) supply capability is limited by insufficient thermal capacity to supply the forecast load under both system normal and network outage conditions. As demand is forecast to continue growing, so is the expected unserved energy demanded from FT.

Supply capability is also limited by the age and condition of the FT 11 kV switchboards which, based on condition monitoring results, are at risk of an increased number of failures and have an increased probability of a catastrophic failure.

Despite the reliability risk of the switchboards, the primary driver of the identified need to augment is the forecast demand and subsequent loading on the 11 kV transformer circuit breakers, buses and transformer cables. With the forecast demand on these assets exceeding their capacity under system normal and network outage conditions, the reliability performance of the FT assets is a secondary driver and inconsequential when assessing the economic value of this constraint.

In line with the purpose of the regulatory investment test for distribution (RIT-D), as outlined in Clause 5.17.1 (b) of the National Electricity Rules, the identified need to address the Flemington area supply constraint is an increase in the sum of customer and producer surplus in the National Electricity Market (NEM); that is an increase in the net market benefit. This net market benefit increase is driven by reducing the cost of expected unserved energy (predominately involuntary load shedding in this case) through augmentation which, as outlined in our Network Development Planning Criteria (JEN PR 0007), is balanced against each development option’s cost to identify the optimal augmentation solution and timing.

This section summarises the station and feeder asset utilisation at FT, based on JEN’s 2015 Load Demand Forecasts Report.

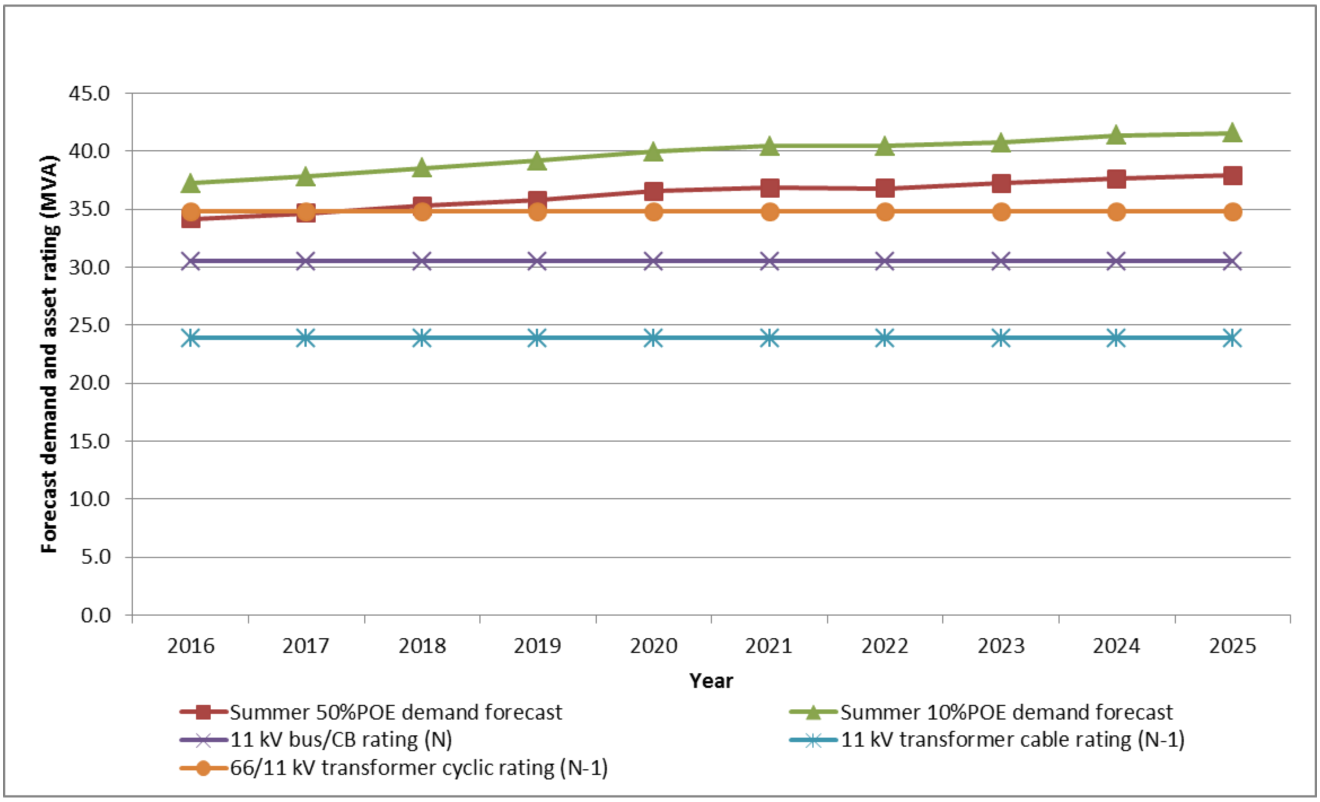
2.1 PRIMARY IDENTIFIED NEED

2.1.1 ZONE SUBSTATION ASSET UTILISATION

Figure 2–1 shows the historical and forecast demand at FT, for 50% POE and 10% POE maximum demand conditions, compared to the ratings of key station assets. It shows that the station’s capacity is limited by the 11 kV buses and transformer circuit breakers under system normal conditions, and by the 11 kV transformer cables under network outage (N-1) conditions, and that load shedding would be required to maintain network loading levels within the ratings of these buses, circuit breakers and transformer cables.

It also shows that, even during outage conditions coincident with peak demand, the FT transformer cyclic ratings have sufficient transformer capacity to meet the 50% POE forecast maximum demand until 2017. Under 10% POE and 50% POE forecast demand conditions, the residual load at risk above the transformer N-1 cyclic rating is expected to be manageable until beyond 2020, by utilising emergency load transfers to Essendon and North Essendon zone substations as required during network outage conditions.

Figure 2–1: Maximum demand against ratings for Flemington Zone Substation



2.2 SECONDARY IDENTIFIED NEED

2.2.1 11 KV FEEDER UTILISATION

In addition to the station asset loading limitations, the supply capacity from FT to its supply area is also limited by the number and capacity of 11 kV feeders connected to FT.

As an assessment guideline applied by JEN, feeders are identified for risk mitigation analysis when their system normal loading reaches 67% of the feeder's summer rating for 50% POE maximum demand conditions. Although augmentation might not necessarily be undertaken at this stage due to a lack of economic viability, JEN considers the identification and investigation of risk mitigation appropriate at this level because loading feeders beyond 67% will typically expose customers to supply risks under outage conditions, due to the lack of available transfer capacity.

Insufficient load transfer capacity following a feeder outage will result in extended customer outages. This has increased societal (market) costs, which, as required by the National Electricity Rules (NER) and the Regulatory Investment Test for Distribution (RIT-D), we aim to minimise through cost efficient augmentation. Extended customer outages also result in penalty costs to JEN under the service target performance incentive scheme (STPIS), as outlined in Clause 6.6.2 of the NER.

Table 2–1 presents the forecast utilisation of FT 11 kV feeders, based on 50% POE summer peak demand conditions. It also shows the utilisation levels averaged across all FT feeders under 50% POE summer peak demand conditions. The utilisation figures are presented based on continuous summer feeder line ratings.

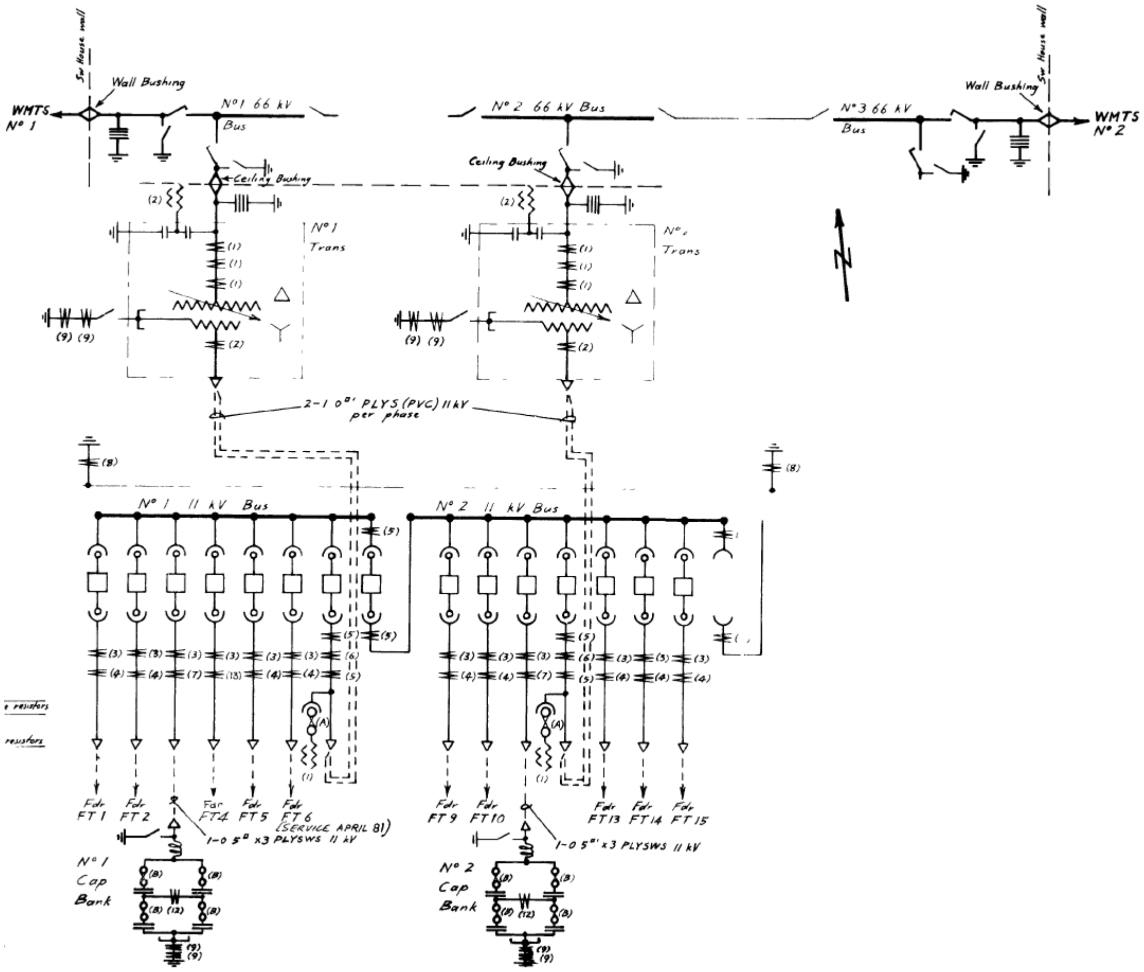
Table 2–1: Forecast utilisation of Flemington Zone Substation feeders

11 kV Feeder	Summer Rating (A)	Forecast Utilisation					
		2016	2017	2018	2019	2020	2021
FT01	375	83.5%	83.1%	82.5%	81.8%	81.6%	82.2%
FT02	260	74.7%	92.8%	112.2%	125.1%	150.3%	182.5%
FT04	590	41.5%	42.7%	43.8%	44.9%	46.1%	48.0%
FT05	345	55.5%	55.6%	56.0%	56.4%	56.7%	57.6%
FT06	180	61.5%	61.0%	60.6%	60.0%	59.9%	60.4%
FT09	300	74.4%	76.1%	82.1%	87.9%	87.7%	88.4%
FT10	375	99.4%	98.7%	97.9%	97.1%	96.9%	97.6%
FT13	375	90.7%	91.8%	92.7%	95.1%	98.0%	102.1%
FT14	375	58.0%	57.6%	57.2%	56.7%	56.6%	57.0%
FT15	345	47.5%	47.1%	46.8%	46.4%	46.2%	46.6%
Average feeder utilisation (%)		68.7%	70.7%	73.2%	75.1%	78.0%	82.2%

As presented in Table 2–1, many of the FT 11 kV feeders are already heavily utilised, and their loading levels are forecast to increase over the next five year period. With the average utilisation forecast to exceed 82% by summer 2020/21, and some of the feeders supplying the north-west areas of the FT supply area expected to exceed their capacity within the five year period, feeder reconfiguration, upgrade, and/or installation of a new 11 kV feeder will be required in the near future. The need for a new feeder from FT to supply the growing load in the Flemington area is detailed in our Distribution Feeders Network Development Strategy (ELE PL 0006).

As shown in the physical arrangement presented in Figure 2–2, the existing 11 kV switchboards at FT don't have any spare circuit breakers available. Additionally, the existing switchboards do not have space provision to install any new circuit breakers. Establishing a new feeder capable of supplying the growing load would therefore require installation of a third 11 kV switchboard. Figure 2–2 also shows that there is provision at FT for a third transformer at the east side of the station, which would connect to the No.3 66 kV bus. However, as mentioned in Section 2.1, if the 11 kV transformer cable, circuit breaker and bus limitations are addressed there is sufficient transformer capacity with the two existing transformers to manage the forecast demand until 2021 or beyond.

Figure 2–2: Flemington Zone Substation physical arrangement



2.2.2 LIMITED TRANSFER AND EMERGENCY BACKUP CAPACITY

Since the 11 kV area supplied by FT is largely separated from the 6.6 kV and 22 kV networks surrounding the east, west and south of FT, there is only limited opportunity to transfer load away from FT. During emergency outage conditions some load can be transferred off the feeders supplying the areas to the north and north-west of FT by extension of the feeders supplied from Essendon Zone Substation (ES) and North Essendon Zone Substation (NS). Due to the additional risk it puts on the already heavily loaded sub-transmission line, feeder and station limitations at ES and NS, as described in our Distribution Annual Planning Report, the transfer capacity away from FT cannot be utilised to manage the system normal limitations. Utilising these transfers under system normal conditions may also limit our ability to maintain and operate the network in a secure manner because the available transfer capacity is required to take assets offline during lighter loaded periods.

Works to provide additional backup supply from ES, as outlined in Section 1.2.2, are nearing completion. When commissioned, the new ES feeder works, which add approximately 6 MVA of emergency transfer capacity, will increase the transfer capacity away from FT to approximately 8.7 MVA during peak demand periods. This load transfer capacity decreases with increased demand and asset utilisation at ES and NS.

JEN does not currently have a spare 66/11 kV transformer. Emergency backup capacity, in the case of a transformer outage, would therefore be limited to the remaining transformer's supply capacity until the faulted transformer could be repaired or replaced, or until supply could be reinstated by other support measures such as a temporary embedded generator.

2.2.3 ASSET CONDITION

The switchgear at FT was manufactured in 1970 by Email (type J18), and is approaching the end of its service life which has been accelerated due to insulation degradation identified through condition monitoring tests. The condition monitoring tests, conducted in 2010, involved measurement of the dielectric dissipation factor (DDF) of the insulating material, and were conducted on both 11 kV buses and six of the 11 kV circuit breakers at FT. Dielectric dissipation factor (DDF) is the ratio of the power dissipated in the major insulation to the power applied. A perfect insulator would have a DDF of zero, whereas a higher DDF indicates deterioration and/or moisture contamination of the insulation.

A DDF above 20 milliradians (2.0%) at 20°C is commonly considered to be an operational hazard[2] due to the increased risk of insulation failure, which could result in catastrophic damage to the switchboard and loss of supply to customers. The condition monitoring test results show DDF measurements between 2.66% and 3.06% for the 11 kV bus tie circuit breaker, as high as 3.98% for the No.1 transformer circuit breaker, and between 1.52% and 3.29% for the other circuit breakers that were tested.

The condition monitoring test results indicate that the main insulating material of the 11 kV buses and circuit breakers at FT have degraded significantly from when the site was first commissioned, and suggest that continuing to operate the station in this state increases the risk of asset failure.

[2] I.A.R Gray, "Dissipation Factor, Power Factor and Relative Permittivity (Dielectric Constant)".

3. ASSESSMENT METHODOLOGY AND ASSUMPTIONS

This section outlines the methodology that JEN applies in assessing its network supply risks and limitations. It also presents key assumptions and input information applied to the assessments described in this development plan.

3.1 PROBABILISTIC ECONOMIC PLANNING

In line with the objective of the National Electricity Rules, JEN's augmentation investment decisions aim to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market.

To achieve this objective, JEN applies a probabilistic planning methodology that considers the likelihood and severity of critical network outages. The methodology compares the forecast cost to consumers of losing energy supply (e.g. when demand exceeds available capacity) against the proposed cost to augment capacity. The annual cost to consumers is calculated by multiplying the expected un-served energy (the expected energy not supplied based on the probability of the supply constraint occurring in a year) by VCR. This is then compared with the annualised augmentation solution cost.

To ensure the net economic benefit is maximised, an augmentation will only be undertaken if the benefits, which are typically driven predominately by a reduction in the cost of expected unserved energy, outweigh the cost of the proposed augmentation resulting in that reduction in unserved energy. Augmentation is not always economically feasible and so this planning methodology carries an inherent risk of not being able to fully supply demand under some possible, but rare, events such as a network outage coinciding with peak demand periods. The probabilistic planning methodology that we have applied is detailed in our Network Augmentation Planning Criteria (JEN PR 0007).

Results of the load at risk and economic net benefit assessment for various augmentation options are included in Appendix C.

3.2 ASSESSMENT ASSUMPTIONS

The key assumptions that have been applied in assessing the Flemington area limitations are outlined in this section, and include:

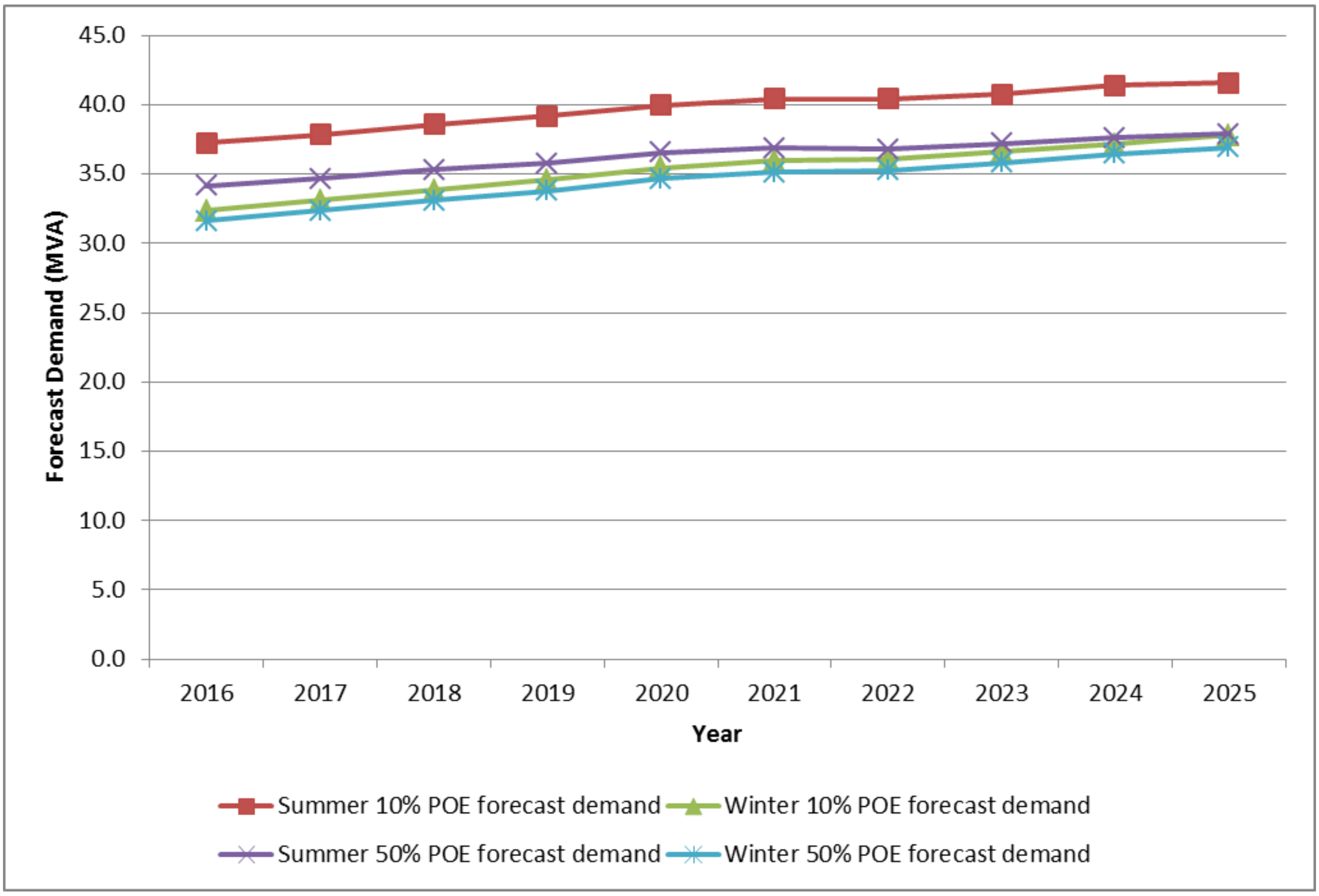
- Demand forecasts;
- Network asset ratings;
- Value of customer reliability (VCR);
- Network outage rates;
- Discount rate; and
- Augmentation costs.

3.2.1 DEMAND FORECASTS

Demand forecasts have been based on the 2015 Load Demand Forecasts Report. Demand at FT is forecast to increase by approximately 1.5% per annum.

Figure 3–1 shows the forecast summer and winter peak demand for 10% POE and 50% POE conditions. Tabulated demand forecasts are also presented in Appendix A.

Figure 3–1: Forecast summer peak demand



3.2.2 NETWORK ASSET RATINGS

In planning its network, JEN applies a summer and winter rating to its temperature sensitive assets, which provides some recognition of the difference in ambient temperature between the two seasons and the heating or cooling effect that the ambient temperature has on an asset's rating.

JEN also applies a cyclic rating to its transformers. This allows the FT transformers to be loaded up to 115% of their normal summer rating under emergency outage conditions.

The cyclic rating relies on the fact that asset loading is not constant over time, but that it cycles between the peak and some lesser loading level, allowing the assets time to dissipate heat and avoid long term heating overloads. Although cyclic ratings can be used for prolonged emergency periods, some loss of life occurs, and each twenty-four hour period that a transformer is loaded at its cyclic rating will result in a 0.03% reduction in the transformer's life expectancy, as detailed in JEN's Transformers Asset Class Strategy (JEN PL 0042).

The Flemington Zone Substation asset ratings are outlined in Table 3–1 through to Table 3–5.

Table 3–1: FT Zone Substation transformer ratings

Station asset	Continuous summer rating (MVA)	N-1 cyclic summer rating (MVA)	Continuous winter rating - (MVA)	N-1 cyclic winter rating (MVA)
No.1 66/11 kV transformer	30.0	34.8	30.0	34.8
No.2 66/11 kV transformer	30.0	34.8	30.0	34.8

Note: winter cyclic transformer ratings have been assumed equal to the summer ratings

Table 3–2: FT Zone Substation 11 kV transformer cable ratings

Station asset	Continuous summer rating (A)	Continuous summer rating (MVA)	N-1 short-term emergency overload rating (A)	N-1 short-term emergency overload rating (MVA)
No.1 11 kV transformer cable	1254	23.9	1668	31.8
No.2 11 kV transformer cable	1254	23.9	1668	31.8

Table 3–3: FT Zone Substation 11 kV bus ratings

Station asset	Summer rating (A)	Summer rating (MVA)
No.1 11 kV bus	1600	30.5
No.2 11 kV bus	1600	30.5

Table 3–4: FT Zone Substation circuit breaker ratings

Circuit Breaker (CB)	Continuous rating (A)	Continuous rating (MVA)
FT01 11 kV feeder CB	400	7.6
FT02 11 kV feeder CB	400	7.6
No.1 11 kV capacitor CB	600	11.4
FT04 11 kV feeder CB	800	15.2
FT05 11 kV feeder CB	400	7.6
FT06 11 kV feeder CB	400	7.6
No.1 11 kV transformer CB	1600	30.5
No.1-2 11 kV bus-tie CB	1200	22.9
FT09 11 kV feeder CB	400	7.6
FT10 11 kV feeder CB	400	7.6
No.2 11 kV capacitor bank CB	600	11.4
No.2 11 kV transformer CB	1600	30.5
FT13 11 kV feeder CB	400	7.6

Circuit Breaker (CB)	Continuous rating (A)	Continuous rating (MVA)
FT14 11 kV feeder CB	400	7.6
FT15 11 kV feeder CB	400	7.6

Table 3–5: FT Zone Substation 11 kV feeder ratings

Feeder	Summer rating (A)	Winter rating (A)	Summer rating (MVA)	Winter rating (MVA)
FT-01	375	375	7.1	7.1
FT-02	260	295	5.0	5.6
FT-04	590	590	11.2	11.2
FT-05	345	375	6.6	7.1
FT-06	180	255	3.4	4.9
FT-09	300	300	5.7	5.7
FT-10	375	375	7.1	7.1
FT-13	375	375	7.1	7.1
FT-14	375	375	7.1	7.1
FT-15	345	385	6.6	7.3

3.2.3 VALUE OF CUSTOMER RELIABILITY

The cost of unserved energy is calculated using the value of customer reliability (VCR). This is an estimate of how much value electricity consumers place on a reliable electricity supply.

In assessing the credible options to alleviate the impact of constraints on its network, JEN applies VCR values based on the Australian Energy Market Operator’s (AEMO) 2014 Value of Customer Reliability Review[3]. Applying the sectorial values developed by AEMO to JEN’s load composition of approximately 46% commercial, 31% residential and 23% industrial customers, JEN has determined a VCR of $38,950/MWh (in 2015 Australian dollars), which includes an escalation factor of 1.33% to account for CPI from AEMO’s 2014 values.

3.2.4 NETWORK OUTAGE RATES

In using a probabilistic economic planning methodology, the network outage rates applied in assessing limitation costs and the benefits of augmentation can have a large impact on the timing of augmentation options.

In assessing the cost of expected unserved energy due to the identified FT limitations, JEN has considered the potential failure of the WMTS-FT 66 kV supply lines and the FT 66/11 kV transformers.

Supply line outage rates have been based on the number of sustained outages recorded over the seventeen year period between 1997 and 2013. During this period the two WMTS-FT 66 kV lines each suffered six sustained outages. The mean time to repair a sustained line outage is estimated at three hours per outage, which is based on the historical average time taken to repair a 66 kV line outage within the JEN network.

[3] AEMO. Available http://www.aemo.com.au/Electricity/Planning/Value-of-Customer-Reliability-review

Despite their inconvenience to JEN and our customers, momentary outages were excluded for the purposes of this assessment due to their limited impact on unserved energy.

66 kV line outages were included because, due to the station switching arrangement, a 66 kV line outage will also result in loss of a transformer, thereby limiting the station's supply capacity to its 'N-1' rating, which is currently 23.9 MVA due to the existing 11 kV transformer cable capacity limitations.

Transformer outages are much less common than line outages, and are therefore based on historical averages across the entire JEN network, rather than being based purely on the transformers at FT. This approach is supported by the fact that, despite being 45 years of age, condition monitoring tests suggest that the FT transformers are currently in very good condition. For this assessment, applying a higher, aged based, failure rate would not truly represent their likelihood of failure, and would likely overestimate the network risk.

Historically, each transformer in JEN's network is expected to fail once in every one hundred years. Due to procurement lead times and the additional work involved in repairing a transformer, the mean time to repair a transformer averages 2.6 months.

Despite the 11 kV switchboard condition tests showing significant insulation deterioration of the bus and circuit breakers (see Section 2.2.3), outage or failure of an 11 kV switchboard asset has been excluded from this assessment for the following reasons:

- Since the system normal and network outage capacity of FT is much lower than the substation's forecast demand, asset condition is not a primary driver of the need to augment the substation's capacity.
- An individual feeder circuit breaker is typically very short in duration and can often be managed by transferring load to surrounding feeders, and therefore won't alter selection of the option to address the zone substation capacity constraint.

Table 3–6 shows the network outage rates applied in calculating the expected unserved energy for the augmentation analysis included in this report.

Table 3–6: Network outage rates

	Transformer	Supply line
Probability of failure	0.01	0.35
Mean time to repair (h)	1898	3
Number of assets	2	2
Unavailability rate	0.433%	0.024%
Combined unavailability per annum	0.457%	

3.2.5 DISCOUNT RATE

A discount rate of 6.24% has been applied in undertaking the Net Present Value (NPV) assessment of options.

3.2.6 AUGMENTATION COSTS

Network option augmentation costs have been estimated by JEN's internal estimation teams. Consideration has been given to recent similar augmentation projects and expected costs based on site specific construction complexities and industry experience.

4. SUMMARY OF POTENTIAL OPTIONS

This section outlines the potential options that have been considered in this report, and outlines the proposed works associated with each of the network development options presented.

Since this Network Development Strategy was approved in March 2015, we have undertaken preliminary design work to firm up the feasibility and deliverability of options. With this work we have expanded the options presented, and included the option of upgrading the existing 11 kV transformer cables in the existing cable ducts. This design work has given us confidence that upgrading the existing 11 kV transformer cables in the existing cable ducts is possible, although potential deliverability risks still exist. Non-network support is discussed under Option 5.

The options considered include:

- Option 1a - Upgrade 11 kV transformer cables and 11 kV switchboards, and install a third 11 kV switchboard (in new switch-room building);
- Option 1b - Upgrade 11 kV transformer cables and 11 kV switchboards, and install a third 11 kV switchboard (in existing switch-room building);
- Option 1c - Upgrade 11 kV transformer cables and 11 kV switchboards (in new switch-room building);
- Option 1d - Upgrade 11 kV transformer cables and 11 kV switchboards (in existing switch-room building);
- Option 2 - Rebuild Flemington Zone Substation;
- Option 3 - Establish a new zone substation to upgrade FT;
- Option 4 - Install a third 66/11 kV transformer (in existing switch-room building);
- Option 5 - Embedded generation and demand management;
- Option 6 - Upgrade 11 kV transformer cables (in existing switch-room building); and
- Option 7 - Upgrade 11 kV transformer cables and 11 kV transformer circuit breakers (in existing switch-room building).

These options are summarised in Table 4–1.

Table 4–1: Zone substation limitation - base case and potential options

Augmentation option	N summer capacity	N winter capacity	N-1 summer capacity	N-1 winter capacity
Base Case – Do Nothing	30.5	30.5	23.9	26.3
Option 1a - Upgrade 11 kV transformer cables and 11 kV switchboards and install a third 11 kV switchboard (in new switch-room building)	45.0	45.0	34.8	34.8
Option 1b - Upgrade 11 kV transformer cables and 11 kV switchboards and install a third 11 kV switchboard (in existing switch-room building)	45.0	45.0	34.6	34.6
Option 1c - Upgrade 11 kV transformer cables and 11 kV switchboards (in new switch-room building)	45.0	45.0	34.8	34.8
Option 1d - Upgrade 11 kV transformer cables and 11 kV switchboards (in existing switch-room building)	45.0	45.0	34.6	34.6
Option 2 - Rebuild Flemington Zone Substation	45.0	45.0	38.0	38.0
Option 3 - Establish a new zone substation to upgrade FT	45.0	45.0	38.0	38.0
Option 4 - Install a third 66/11 kV transformer (in existing switch-room building)	61.0	61.0	30.5	30.5
Option 6 - Upgrade 11 kV transformer cables (in existing switch-room building);	30.5	30.5	30.5	30.5
Option 7 - Upgrade 11 kV transformer cables and 11 kV transformer circuit breakers (in existing switch-room building);	30.5	30.5	30.5	30.5

4.1 BASE CASE

The assessment of credible options is based on a cost-benefit analysis that considers the future expected unserved energy of each credible option, compared with the base case where no augmentation option is implemented.

Under this base case, the action required to ensure that loading levels remain within the capabilities of assets is involuntary load shedding of JEN's customers. The cost of involuntary load shedding is calculated using the VCR which, for the JEN network, is currently estimated at $38,950/MWh (Real $2015), as described in Section 3.2.3.

The 'Base Case' option gives the basis for comparing the cost-benefit assessment of each credible augmentation option. The base case is presented as a do nothing option, where we would continue managing network asset loading through involuntary load shedding.

Since there is no augmentation associated with the base case (do nothing) option, this is a zero cost option.

4.2 OPTION 1 – NEW FLEMINGTON ZONE SUBSTATION 11 KV ASSETS

This option is to upgrade the thermally limited 11 kV assets at FT by installing new, higher capacity, 11 kV transformer cables and 11 kV switchboards.

Four alternative sub-options are considered under Option 1. The four options have the common works of upgrading the 11 kV transformer cables and two existing 11 kV switchboards, but differ as follows:

- Option 1a - is for the common works in a new switch-room building and also includes installing a third 11 kV switchboard.
- Option 1b - is for the common works in the existing switch-room building and also includes installation of a third 11 kV switchboard.
- Option 1c - is for the common works in a new switch-room building.
- Option 1d – is for the common works in the existing switch-room building.

While upgrade of the existing switchboards with two new switchboards has been assessed, JEN’s modern day standard switchboard installation has a reduced number of available feeder/capacitor bank circuit breakers compared to the switchboards currently installed at FT. JEN’s standard 11 kV switchboard installation consists of five feeder/capacitor bank circuit breakers, in addition to a bus-tie circuit breaker and a transformer circuit breaker. To enable reconnection of the ten existing feeders and two existing capacitor banks at FT, upgrade with three 11 kV switchboards will be required. Installation of the third switchboard also provides spare circuit breakers to allow for connection of future feeders, the first of which is planned for 2017 as outlined in our Distribution Feeders Network Development Strategy (ELE PL 0006).

4.3 OPTION 2 – REDEVELOP FLEMINGTON ZONE SUBSTATION

This option is to completely redevelop Flemington Zone Substation at the existing site.

The proposed scope of work for Option 2 includes redevelopment of FT with:

- Installation of a new indoor 11 kV switch-room building;
- Installation of three new 11 kV switchboards;
- Installation of two new 11 kV transformer cables;
- Installation of 66 kV gas insulated switchgear; and
- Installation of two new 20/33 MVA transformers.

4.4 OPTION 3 – ESTABLISH A NEW ZONE SUBSTATION

This option is to establish a new Flemington Zone Substation at an alternative site in the Flemington area and decommission, demolish, clean-up and sell the existing site. The proposed scope of works for Option 3 includes:

- Purchase land for a new zone substation in the Flemington area;
- Construct a new 66/11 kV zone substation in the Flemington area, consisting of 66 kV gas insulated switchgear and two 20/33 MVA transformers;

- Reroute, extend and connect the existing WMTS-FT 66 kV lines to the new zone substation;
- Reroute, extend and connect the existing FT 11 kV feeders to the new zone substation;
- Reroute, extend and connect any existing protection and communication circuits to the new zone substation; and
- Demolish, clean-up and sell the existing FT site.

4.5 OPTION 4 – INSTALL A THIRD 66/11 KV TRANSFORMER

This option is to install a third 66/11 kV transformer in the existing switch-room building.

The proposed scope of works for Option 4 includes:

- Installation of a 66/11 kV 20/33 MVA transformer;
- Installation of a third 11 kV switchboard; and
- Installation of two 66 kV bus-tie circuit breakers.

4.6 OPTION 5 – EMBEDDED GENERATION AND DEMAND MANAGEMENT

Non-network alternatives, such as embedded generation or demand management can alleviate supply risks caused by network inadequacies, and can therefore potentially defer the need for major network augmentation. The embedded generation or demand management schemes for this project would need to be connected to, and supply into FT's 11 kV distribution network to effectively offload the 11 kV transformer cables and 11 kV feeders within the FT supply area.

Possible embedded generators could include:

- Gas turbine power stations;
- Co-generation from industrial processes; and
- Generation using renewable energy, such as solar, wind or land-fill powered generation.

JEN currently has no significant embedded generators (>1 MW) connected to Flemington, Essendon or North Essendon feeders or zone substations that could be used to defer the need for the proposed preferred solution. As such, the option of contracting embedded generation for network support during hours of peak demand is not viable.

A reduction of peak demand, using demand management, could be achieved by customers shifting their usage to off-peak, using high efficiency, low energy appliances, and by reducing energy wastage. If such schemes were established, their effectiveness would depend on the extent of customer uptake.

Demand management schemes could include:

- Off-peak usage incentives, in exchange for a reduced energy tariff; and
- Interruptible load at a reduced electricity tariff, which would be covered by a supply agreement that the load can be interrupted during network emergencies.

We have undertaken a high level assessment of a potential demand response solution using the 2015 Load Demand Forecasts Report and available emergency load transfers of 8.7 MVA. The results are presented in Table 4–2 below. The results show that, while the annualised cost of expected unserved energy currently exceeds the annual cost of the demand response option, meaning that a demand response option would likely have positive net market benefits, the annualised cost of the demand response solution far exceeds the annualised cost of the proposed solution, showing that the proposed solution has a lower long-term cost, while providing higher benefits.

Table 4–2: Demand Response Option Assessment for FT Capacity Constraint

Demand Response (Fast DR) Scenario	
Risk in 2017	
Peak Risk (MVA)	5.2 (assumes 8.7 MVA of load transfer capacity)
Number of hours at risk (per year)	912
Expected dispatch hours (per year)	4
Demand response program assumptions	
Number of customers	15
Total (MW)	5.2
Expected annual demand response (MWh)	21
Capacity payment unit rate ($/MWh)	$30,000
Customer Demand Response Payments	
Setup cost ($)	$533,000
Total dispatch fee ($)	$156,000
Total Cost (probability weighted)	
Year 1 – 2017 ($)	$689,000

Non-network alternatives will be assessed in detail as part of the Regulatory Investment Test for Distribution (RIT-D) that will be conducted to assess the Flemington Zone Substation capacity constraint. It is anticipated that non-network alternatives will not be economically beneficial compared to the preferred solution outlined in this report due to the:

- High proportion of load at risk in the Flemington supply area; and
- Supply area being predominately residential, which leads to challenging and costly demand management customer acquisition.

Nonetheless, JEN has initiated the RIT-D consultation process and will compare any non-network alternatives to the current proposed investment option,

4.7 OPTION 6 – UPGRADE 11 KV TRANSFORMER CABLES (IN EXISTING SWITCH-ROOM BUILDING)

This option is to upgrade the existing 11 kV transformers cables by reusing the existing cable ducts.

The previous draft of this Network Development Strategy outlined safety and constructability issues with upgrading the existing 11 kV transformer cables in the existing switch-room building. Following additional assessment and preliminary design work undertaken since our initial submission, we have gained confidence that upgrading the existing 11 kV cables in the existing building is possible, although it still has risks. Some of the risks that our initial design work indicates are manageable, but can't be completely ruled out, include:

- Bentonite – while our records suggest that bentonite has not been installed in the existing cable ducts, as originally thought, this can only be confirmed with a network outage. If we discover that the cable ducts have been filled with bentonite, these ducts will be unusable and additional works will be required to upgrade the existing cables.
- Cable duct diameter – Initial design suggests that a suitable cable capacity can be obtained with cables that will fit in the existing cable ducts, which are 100mm in diameter. However, JEN's standard cable duct size for cables suppling an 11 kV 20/30 MVA or 20/33 MVA transformer, is 150mm diameter.
- Number of cables per phase – FT was designed with only two cables, and therefore cable ducts, per phase per transformer. JEN's standard installation for cables supplying an 11 kV 20/30 MVA or 20/33 MVA transformer is for three cables per phase per transformer. As for the cable duct diameter, initial design indicates that a suitable cable capacity can be obtained with the two ducts per phase, however this will be confirmed during detailed design.
- Cable bending radius – larger cables, which will be required to achieve a suitable capacity, are typically stiffer and require a larger bending radius for cable installation. The available site layout diagrams suggest that a suitable bending radius is available, however this will be confirmed during detailed design.

Despite the deliverability risks that exist, given the preliminary design work that has been undertaken, JEN is satisfied that the deliverability risk is low enough to now consider upgrading the existing transformer cables in the existing cable ducts as a viable option. Detailed design in 2016 will determine the viability of using the existing cable ducts.

4.8 OPTION 7 – UPGRADE 11 KV TRANSFORMER CABLES AND 11 KV TRANSFORMER CIRCUIT BREAKERS (IN EXISTING SWITCH-ROOM BUILDING)

This option is to upgrade the existing 11 kV transformers cables and the existing 11 kV transformer circuit breakers, without upgrading the entire 11 kV switchboards.

JEN has obtained indicative cost estimates to upgrade the existing 1600 A transformer circuit breakers with 2000 A circuit breakers. While the cost estimates indicate that upgrading is likely viable, a network outage is required to measure the location and fittings arrangement of the existing circuit breaker to ensure an upgrade is possible, and to provide a firm cost estimate. Space and heating constraints may prevent a higher capacity upgrade circuit breaker from being installed, however this cannot be confirmed without a network outage and detailed design work.

5. OPTIONS ANALYSIS

This section presents the base case limitation and summarises the augmentation analysis results of potential options. The annualised Base Case (do nothing) limitation cost for the next ten year period is presented, as is the net market benefit calculated for each potential option. The net market benefit analysis has been assessed considering the network risk and expected augmentation costs for the 15 year period from 2016 to 2030. The emergency load transfer capacity from FT, to neighbouring zone substations Essendon (ES) and North Essendon (NS), are included in the revised expected unserved energy and cost of expected unserved energy values presented in this report. While the load transfers can offload much of the expected unserved energy under emergency outage conditions, these load transfers cannot be utilised to offload the system normal expected unserved energy.

Each potential augmentation option has been ranked according to its net market benefit, being the difference between the gross market benefit and the total lifecycle capital cost of expected augmentations within the 15 year assessment period.

Appendix B includes the load at risk and economic assessment spreadsheets.

5.1 EXISTING NETWORK LIMITATION

This section presents the existing annualised thermal limitation cost for the next ten year period, due to the 11 kV transformer cable, bus and circuit breaker limitations. The annualised residual limitation costs that would exist, assuming implementation of each potential option, are presented in Appendix C.

5.1.1 BASE CASE

If no action is taken to increase the supply capacity at Flemington Zone Substation (FT), involuntary load shedding would be required to ensure that loading levels remain within asset ratings under system normal and network outage conditions.

The impact of the limitation under the base case is presented in Table 5–1.

Table 5–1: Limitation impact under Base Case

Year	Max load at Risk (MVA)	Annual Hours at Risk (h)	Expected Unserved Energy (MWh)	Cost of Expected Unserved Energy ($k)
2016	13.3	735	71.3	$2,778
2017	13.9	912	101.6	$3,956
2018	14.7	1137	152.9	$5,954
2019	15.3	1362	222.3	$8,658
2020	16.1	1689	356.1	$13,870
2021	16.5	1869	449.5	$17,506
2022	16.5	1884	463.0	$18,035
2023	16.8	2093	595.0	$23,173
2024	17.5	2325	774.4	$30,164

Year	Max load at Risk (MVA)	Annual Hours at Risk (h)	Expected Unserved Energy (MWh)	Cost of Expected Unserved Energy ($k)
2025	17.7	2506	944.3	$36,780

5.2 MARKET BENEFITS

Net market benefits are the actual benefits having considered the cost (negative benefit) to implement the potential project.

Table 5–2 shows the proposed expenditure within the 2016-2020 period for each potential option, which is the cost that this Network Development Strategy is aiming to justify. It also presents the total lifecycle project cost, which is the expected expenditure over the 2016-2030 period and, depending on works included in the 2016-2020 project, includes the cost of future works such as new 11 kV switchboards in 2021 and replacement transformers in 2030. Using the total lifecycle cost to calculate the net market benefit allows selection of the best longer-term network development plan, rather than just considering the short-term costs and benefits.

The options have been ranked based on their net present value of net market benefit, which is the total benefits provided over the 2016-2030 period, minus the total lifecycle project cost (2016-2030), which includes the both 2016-2020 project cost and future costs that JEN expects within that period.

The results show that Option 1b, Upgrade 11 kV transformer cables and 11 kV switchboards and install a third 11 kV switchboard (in existing switch-room building), is the option that maximises the net market benefits, and is therefore the proposed preferred option to augment the supply capacity at FT.

Table 5–2: Market benefits of augmentation options relative to the base case

Augmentation option	2016-2020 project cost ($m, direct)	NPV of net market benefit ($m)	Project ranking	Total lifecycle project cost (2016-2030) ($m, direct)
Option 1a - Upgrade 11 kV transformer cables and 11 kV switchboards and install a third 11 kV switchboard (in new switch-room building)	8.03	178.17	3	9.83
Option 1b - Upgrade 11 kV transformer cables and 11 kV switchboards and install a third 11 kV switchboard (in existing switch-room building)	5.39	180.51	1	7.45
Option 1c - Upgrade 11 kV transformer cables and 11 kV switchboards (in new switch-room building)	6.75	174.56	6	13.43
Option 1d - Upgrade 11 kV transformer cables and 11 kV switchboards (in existing switch-room building)	4.10	180.48	2	7.51
Option 2 - Rebuild Flemington Zone Substation	9.84	175.77	5	9.88
Option 3 - Establish a new zone substation to upgrade FT	32.20	159.46	7	28.53
Option 4 - Install a third 66/11 kV transformer (in existing switch-room building)	5.23	177.17	4	10.82

Augmentation option	2016-2020 project cost ($m, direct)	NPV of net market benefit ($m)	Project ranking	Total lifecycle project cost (2016-2030) ($m, direct)
Option 6 - Upgrade 11 kV transformer cables (in existing switch-room building)	0.92	(6.85)	8	7.00
Option 7 - Upgrade 11 kV transformer cables and 11 kV transformer circuit breakers (in existing switch-room building)	1.18	(7.08)	9	7.23

5.3 PREFERRED OPTION OPTIMAL TIMING

The optimal timing of augmentations within the 2016-2020 period have been identified by comparing the annualised augmentation benefit, being the reduction in expected unserved energy by undertaking the proposed augmentation, compared to the annualised cost of the augmentation. The annualised cost of augmentation is calculated using an expected project life of 50 years, discount rate of 6.24%, and the total capital cost of the augmentation proposed within the 2016-2020 period. The annualised cost calculation does not use the total lifecycle cost, which also includes augmentation costs considered after 2020.

The annualised cost of the proposed preferred option, Option 1b - Upgrade 11 kV transformer cables and 11 kV switchboards and install a third 11 kV switchboard (in existing switch-room building), is $460k. The annualised benefits already exceed these annualised costs, so the optimal timing is to complete this project as soon as possible. Given the project planning, ordering of long lead items and works involved in this project, JEN intends to complete this project by November 2017, which is considered the earliest possible date.

6. CONCLUSION AND NEXT STEPS

The assessment outlined within this report shows that the primary limitations associated with Flemington Zone Substation (FT) are the thermal ratings of the 11 kV transformer circuit breakers, 11 kV buses and the 11 kV transformer cables. The condition of the 11 kV switchboards or 66/11 kV transformers are not considered to be a primary driver of the need to augment capacity at FT. The transformers are in very good condition for their age, and are not showing any signs of deterioration. While the switchboards have signs of deterioration, any additional benefits resulting from their condition are difficult to accurately quantify and would be significantly outweighed by the demand driven risks and resulting benefits.

The additional assessment and initial design work undertaken since our March 2015 version of this Network Development Strategy has identified that:

- Upgrading the existing 11 kV transformer cables and 11 kV switchboards in the existing building is likely to be possible.
- While upgrading the existing 11 kV transformer cables is technically achievable, the cost to undertake this option as a stand-alone project ($0.92 million) provides negative $6.85 million net market benefits.
- Upgrading the existing 11 kV transformer cables and 11 kV switchboards, with installation of a third 11 kV switchboard remains the option that maximises the net present value of market benefits. However, since undertaking this work within the existing building is now considered feasible, the revised estimate to complete this preferred option has reduced to $5,385,240 ($2015 real direct un-escalated).

Following implementation of the proposed preferred solution, there will be some residual risk due to the existing transformers' thermal capacities. However, based on the demand levels presented in the 2015 Load Demand Forecasts Report, this residual risk is considered to be economically manageable until 2021 or beyond.

6.1 PREFERRED SOLUTION

The assessment shows that the preferred solution is to upgrade the 11 kV transformer cables and 11 kV switchboards in the existing switch-room building, with installation of a third 11 kV switchboard.

Table 6–1 shows the total project cost breakdown for Option 1b.

Table 6–1: Option 1 Cost Estimate Breakdown

	$ Real2015 (M)
Direct Cost	$5.39
Escalation	$0.10
Business Overheads	$1.53
Total	$7.01

Applying the discount rate of 6.24% per year, the preferred solution has a net market benefit of $180.5 million.

6.2 NEXT STEPS

On 22 October 2015, JEN published Stage 1, the non-network options report, of the Flemington Electricity Supply RIT-D. In accordance with the requirements of the National Electricity Rules, the non-network options report describes:

- The identified need in relation to the Flemington network;
- Potential options that may address this need; and
- The technical characteristics of a credible non-network option.

Submissions to the Flemington Electricity Supply RIT-D Non-Network Options Report close on 29 January 2016, after which time JEN will assess all options and submissions in detail, and publish Stage 2, the draft project assessment report, by 30 June 2016.

A detailed scope of work covering all aspects of the proposed option will be prepared in conjunction with the primary plant and secondary and control systems teams. The scope of work will be issued to JEN's Works Delivery team for development of a firmer project cost, which will form part of the business case seeking internal approval for the preferred option.

Alongside internal approval of the project, JEN will continue working through the Regulatory Investment Test for Distribution (RIT-D) process to consult with industry and confirm the proposed preferred option maximises the net economic benefits, or whether any non-network alternatives exist that offer a superior net benefit.

APPENDIX A: FORECASTS

This Appendix A presents the maximum demand forecasts for Flemington Zone Substation, which have an average summer growth rate of 1.2% per annum and average winter growth rate of 1.7% per annum.

Table A–1: Maximum demand forecasts for Flemington Zone Substation

Year	Summer 50% POE demand (MVA)	Winter 50% POE demand (MVA)	Summer 10% POE demand (MVA)	Winter 10% POE demand (MVA)
2016	34.2	31.6	37.2	32.4
2017	34.7	32.4	37.8	33.1
2018	35.3	33.1	38.6	33.8
2019	35.8	33.8	39.2	34.6
2020	36.6	34.7	40.0	35.4
2021	36.9	35.1	40.4	36.0
2022	36.8	35.2	40.4	36.1
2023	37.2	35.8	40.7	36.6
2024	37.6	36.4	41.4	37.1
2025	37.9	36.9	41.6	37.8

APPENDIX B: ECONOMIC ASSESSMENT SPREADSHEETS

Detailed cost-benefit assessments and load at risk assessments are included as the Microsoft Excel spreadsheet attachments listed:

- ZS Load at risk - FT thermal capacity (November 2015)
- JEN economic cost benefit analysis – FT ZS Capacity Constraint (November 2015)

APPENDIX C: POST AUGMENTATION LIMITATION COST

This Appendix C shows the expected unserved energy that would remain until 2025, following implementation of each potential option considered. With the available emergency load transfer capacity of 8.7 MVA included in the assessment, options 1a, 1b, 1c, 1d, 2, 3 and Option 4 remove all the expected unserved energy within the next ten year period.

Option 6 and Option 7 don't address the system normal risk, and therefore have a much lower reduction in expected unserved energy, as shown in Table 0–1 and Table 0–2 respectively.

Table 0–1: Limitation impact under Option 6

Year	Max Load at Risk (MVA)	Annual Hours at Risk (h)	Expected Unserved Energy (MWh)	Cost of Expected Unserved Energy ($k)
2016	6.7	45	71.2	$2,774
2017	7.3	65	101.5	$3,952
2018	8.1	94	152.7	$5,947
2019	8.7	136	222.1	$8,649
2020	9.5	204	355.8	$13,857
2021	9.9	244	449.1	$17,491
2022	9.9	252	462.6	$18,020
2023	10.2	310	594.5	$23,155
2024	10.9	382	773.8	$30,141
2025	11.1	448	943.6	$36,754

Table 0–2: Limitation impact under Option 7

Year	Max Load at Risk (MVA)	Annual Hours at Risk (h)	Expected Unserved Energy (MWh)	Cost of Expected Unserved Energy ($k)
2016	6.7	45	71.2	$2,774
2017	7.3	65	101.5	$3,952
2018	8.1	94	152.7	$5,947
2019	8.7	136	222.1	$8,649
2020	9.5	204	355.8	$13,857
2021	9.9	244	449.1	$17,491
2022	9.9	252	462.6	$18,020
2023	10.2	310	594.5	$23,155
2024	10.9	382	773.8	$30,141
2025	11.1	448	943.6	$36,754