Service constraints at Clyde North Zone Substation

Regulatory Investment Test for Distribution

Final Project Assessment Report

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1 Executive Summary

AusNet Services is a regulated Victorian Distribution Network Service Provider (DNSP) that supplies electrical distribution services to more than 745,000 customers. Our electricity distribution network covers eastern rural Victoria and the fringe of the northern and eastern Melbourne metropolitan area.

As expected by our customers and required by the various regulatory instruments that that we operate under, AusNet Services aims to maintain service levels at the lowest possible cost to our customers. To achieve this, we develop forward looking plans that aim to maximise the present value of economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

Our planning approach includes the application of a probabilistic planning methodology, which means that some load cannot be supplied under rare but possible conditions, such as during extreme demand conditions or with a network element out of service. Where relevant, we also prepare, publish, and consult on a regulatory investment test for distribution (RIT-D), which further helps ensure all credible options to address an identified need and considered, and the best option is selected.

This Final Project Assessment Report (FPAR) is the final stage of the RIT-D consultation process to address the existing and emerging service level constraints in the Clyde North Zone Substation (CLN) supply area. It follows the publication of our non-network options report, which invited non-network proponents to engage on alternatives to our preferred network solution. We received two responses from non-network proponents, both of which were non-conforming offers. On the basis of further analysis, we concluded that neither response constituted a credible option.

We subsequently published the Draft Project Assessment Report (DPAR) for CLN in March 2022. We did not receive any submissions in relation to that report. With the exception of relatively minor drafting changes, the content and findings presented in this FPAR are essentially unchanged from the DPAR.

This FPAR has been prepared by AusNet Services in accordance with the requirements of clause 5.17 of the National Electricity Rules (NER). This FPAR complies with the requirements of Clause 5.17.4(j) of the NER, as detailed in section 7 of this document, and the AER's RIT-D application guidelines.

1.1 Identified need

CLN consists of two 66/22 kV 20/33 MVA transformers supplying two 22 kV buses and eight 22 kV feeder circuits. The substation supplies approximately 35,000 residential, commercial, industrial and agricultural customers in Victoria's southeast growth corridor.

The supply area is surrounded by Cranbourne (CRE) and Hampton Park (HPK) Zone Substations in the west, Berwick North (BWN) Zone Substation in the north and Officer (OFR) Zone Substation in east.

CLN Zone Substation is a summer peaking substation with a forecast maximum demand growth rate averaging 4.3% per annum over the next 10-year period. The growth in demand is predominately driven by the significant expansion of residential and commercial development in Melbourne's southeast growth corridor.

The zone substation summer maximum demand recorded in 2019/20 was 73.4 MVA. The forecast summer maximum demand is given in Table 1.

Table 1: Forecast Summer Maximum Demand

Probability of Exceedance (POE)	Forecast Summer Maximum Demand 2022/23 (MVA)	Forecast Summer Maximum Demand 2026/27 (MVA)
50%	80.9	97.2
10%	94.3	113.5

The zone substation capacity, consisting of a nameplate rating of 66 MVA, and 'N' and 'N-1' cyclic ratings of 87.3 MVA and 43.5 MVA respectively, is insufficient to reliably supply the forecast maximum demand, meaning that the current level of supply to our customers is expected to diminish if some service level risk mitigation action is not undertaken.

In addition to the zone substation constraints, supply capacity is also limited at the feeder circuit level, where electricity demand growth is forecast to exceed the capacity of multiple feeder circuits, similarly resulting in a service level reduction unless some risk mitigation action is taken.

1.2 Options considered and preferred option

This FPAR considered the following potentially credible options that may be capable of meeting the identified:

1. Do nothing (counterfactual);
2. Large customer demand management network support;
3. Residential battery network support;
4. Embedded generation network support;
5. Network reconfiguration;
6. Installation of a third transformer installation at CLN Zone Substation;
7. Installation of a third transformer and a new 22 kV switch room at CLN Zone Substation; and
8. Hybrid of Options 4 & 5 - by contracting with an embedded generation provider and transferring load from CLN Zone Substation to neighbouring zone substations.

As already noted, our non-network options report in relation to the identified need at CLN did not produce any credible non-network options. As a consequence, those options that included a non-network component, being Options 2, 3, 4 and 8, are no longer considered to be credible options.

Following a detailed assessment of the remaining options in accordance with the RIT-D, Option 7 has been identified as the preferred option.

1.3 Contact details

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2 Background

2.1 Existing network

CLN consists of two 66/22kV 20/33 MVA transformers supplying two 22 kV buses and eight 22 kV feeder circuits. The substation supplies approximately 35,000 residential, commercial, industrial and agricultural customers in Victoria's southeast growth corridor.

The supply area is surrounded by Cranbourne (CRE) and Hampton Park (HPK) Zone Substations in the west, Berwick North (BWN) Zone Substation in the north and Officer (OFR) Zone Substation in east, as shown in Figure 1. Electricity demand and population growth in the southeast growth corridor has been strong in recent years, which led to the establishment of CLN zone substation in 2004 to help manage growth by off-loading HPK and BWN zone substations and feeders.

In 2012, CRE zone substation was established to further off-load HPK zone substation and the feeders heading west and south, and CLN zone substation and the feeders heading west, north and south. Prior to establishing CLN zone substation, the areas shown in Figure 1 were supplied from the combination of BWN and HPK zone substations.

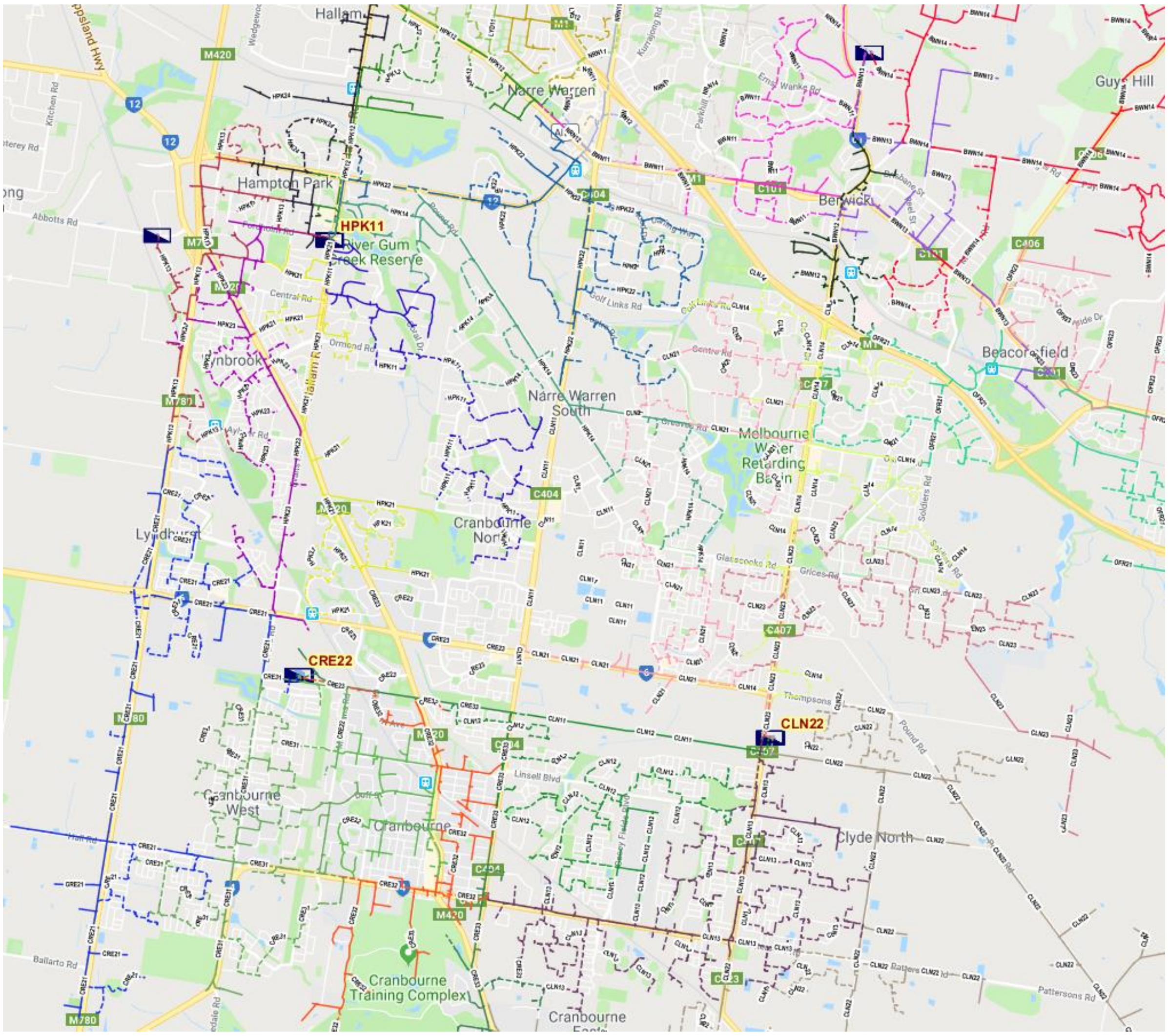

Figure 1: CLN and surrounding zone substation geographical feeder arrangements

The configuration of the primary electrical circuits within and surrounding CLN is as shown in the single line diagram of Figure 2.

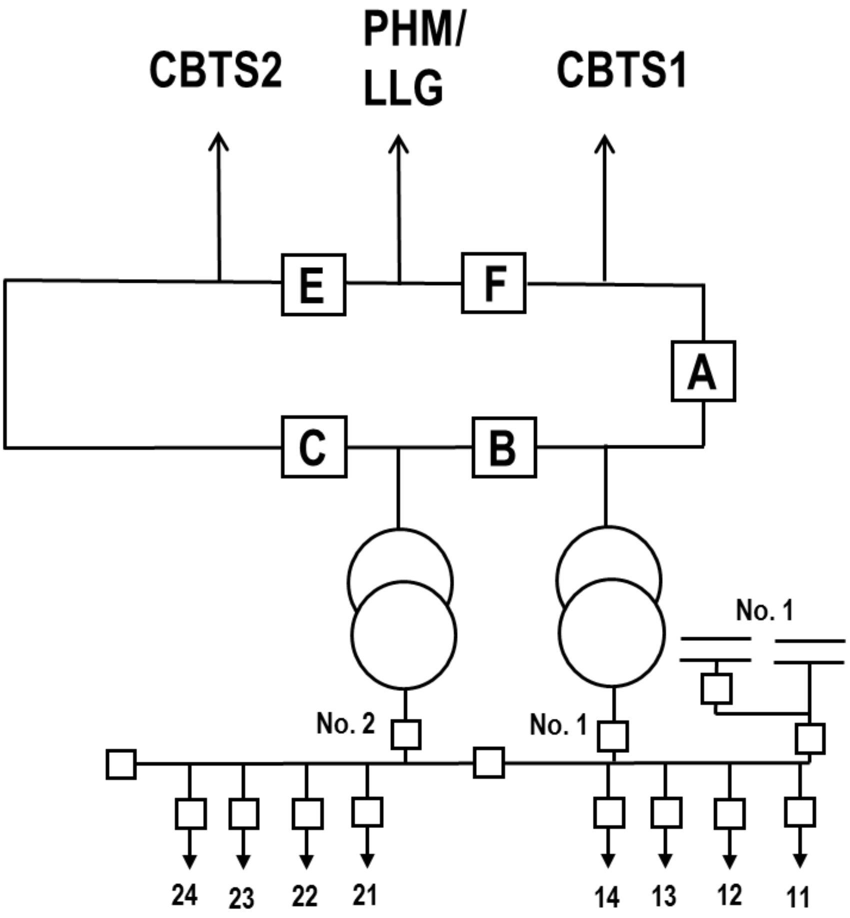

Figure 2: Existing Single Line Diagram of CLN

2.2 Customer Composition

CLN has eight 22 kV feeders supplying AusNet Services' customers. Table 2 provides detail of the 22 kV supply feeders.

Table 2: CLN feeder information

Feeder	Feeder Length (km)	Feeder Description	Number of Customers	Customer Type
CLN11	121.6	Summer peaking, rural short feeder	7,789	95.7% residential 1.7% commercial 0.2% industrial 2.4% farming
CLN12	29.1	Summer peaking, urban feeder	5,126	98.6% residential 1.4% commercial
CLN13	38.56	Summer peaking, urban feeder	5,730	98.7% residential 1.3% commercial
CLN14	27.4	Summer peaking, urban feeder	5,281	98.2% residential 1.8% commercial

Feeder	Feeder Length (km)	Feeder Description	Number of Customers	Customer Type
CLN21	31.3	Summer peaking, urban feeder	5,508	98.4% residential 1.3% commercial 0.1% industrial 0.2% farming
CLN22	14.3	Summer peaking, rural short feeder	931	99.2% residential 0.8% commercial
CLN23	29.9	Summer peaking, urban feeder	4,435	98.7% residential 1.2% commercial 0.8% farming
CLN24	11.7	Summer peaking, rural short feeder	1,227	84.5% residential 15.2% commercial 0.2% industrial 0.1% farming

3 Identified Need

Electricity demand supplied from CLN is forecast to grow an average of 4.3% per annum over the forward planning period to 2031. This growth in demand is predominately due to new housing and commercial developments in the southeast growth corridor.

AusNet Services' asset condition monitoring suggests the zone substation assets are generally in good or very good condition, and therefore have a low probability of failing and reducing the substation's supply capacity. Despite the low probability of failure, the loading on the zone substation already exceeds the substation's firm supply capacity and is forecast to exceed its system normal supply capacity by 2023.

In addition to the zone substation constraints, supply capacity is also limited at the feeder circuit level, where electricity demand growth is forecast to exceed the capacity of multiple feeder circuits, in the CLN and surrounding zone substation supply areas during the 2021 to 2026 regulatory period.

To provide the optimal balance of cost and reliability to our customers, action is required to manage the expected level of involuntary load shedding that would otherwise be required to maintain loading to within asset capabilities during both system normal and network asset outage conditions.

4 Assumptions underpinning the identified need

The purpose of this chapter is to summarise the key input assumptions that underpin the identified need described in the previous chapter.

4.1 Regulatory Obligations

In addressing the identified need, we must satisfy our regulatory obligations, which we summarise below.

Clause 6.5.7 of the National Electricity Rules requires AusNet Services to only propose capital expenditure required in order to achieve each of the following:

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

Section 98(a) of the Electricity Safety Act requires AusNet Services to:

> *design, construct, operate, maintain and decommission its supply network to minimise as far as practicable –*
>
> *(a) the hazards and risks to the safety of any person arising from the supply network; and*
>
> *(b) the hazards and risks of damage to the property of any person arising from the supply network; and*
>
> *(c) the bushfire danger arising from the supply network.*

The Electricity Safety act defines 'practicable' to mean having regard to –

> *(a) severity of the hazard or risk in question; and*
>
> *(b) state of knowledge about the hazard or risk and any ways of removing or mitigating the hazard or risk; and*
>
> *(c) availability and suitability of ways to remove or mitigate the hazard or risk; and*
>
> *(d) cost of removing or mitigating the hazard or risk.*

Clause 3.1 of the Electricity Distribution Code requires AusNet Services to:

> *(b) develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of its distribution system assets and plans for the establishment and augmentation of transmission connections:*

(i) *to comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in this Code;*

(ii) *to minimise the risks associated with the failure or reduced performance of assets; and*

(iii) *in a way which minimises costs to customers taking into account distribution losses.*

Under clause 5.2 of the Electricity Distribution Code, AusNet Services:

> *must use best endeavours to meet targets required by the Price Determination and targets published under clause 5.1 and otherwise meet reasonable customer expectations of reliability of supply.*

4.2 Asset Condition

To provide a consistent assessment of the condition of an asset, AusNet Services applies a common condition scoring methodology. This methodology uses the known condition details of each asset and grades that asset against common asset condition criteria.

Asset condition is measured with reference to an asset health index on a declining condition scale from C1 to C5, as outlined in Table 3.

AusNet Services' strategy and approach to monitoring the condition of assets is further described in *AMS 10-13 Condition Monitoring*.

Table 3: Asset Condition Score and Remaining Service Potential

Condition Score	Condition	Condition Summary
C1	Very good	Initial service condition
C2	Good	Deterioration has minimal impact on asset performance. Minimal short term asset failure risk.
C3	Average	Functionally sound showing some wear with minor failures, but asset still functions safely at adequate level of service.
C4	Poor	Advanced deterioration – plant and components function but require a high level of maintenance to remain operational.
C5	Very Poor	Extreme deterioration approaching end of life with failure imminent.

Asset conditions are discussed in the Asset Health Reports for the key asset classes, namely power transformers, instrument transformers and circuit breakers, with information on asset condition rankings, recommended risk mitigation options and replacement timeframes.

A summary of the condition of key assets at CLN is provided in Table 4.

Table 4: CLN asset condition scores

Asset Type	Number of assets by Condition Score				
	C1	C2	C3	C4	C5
66 kV Circuit Breakers	5				
66 kV Current Transformers	12				
66 kV Voltage Transformers	11		2		
66/22 kV Power Transformers		2			
22 kV Circuit Breakers	14	1			
22 kV Current Transformers	22				
22 kV Voltage Transformers	4				

These conditions scores are then used to calculate the asset failure rates using the Weibull Hazard function, as presented in Equation 1.

Equation 1: Weibull Hazard Function

$$r(t) = \frac{\beta t^{\beta-1}}{\eta^{\beta}}$$

Where:

t = Time (condition based age)

η = Characteristic life (Eta)

β = Shape Parameter (Beta)

A Beta (β) value of 3.5 has been used to calculate the failure rates of all assets considered in the zone substation risk-cost model.

The condition based age (t) depends on the specific asset's condition and characteristic life (η). The characteristic life represents that average asset age at which 63% of the asset class population is expected to have failed. Table 5 gives the characteristic life values for each asset classes considered in the risk-cost model.

Table 5: Equipment Characteristic Life Values

Equipment	Characteristic Life (η) (years)
Power transformers	50
Circuit breakers	45
Voltage transformers	40
Current transformers	30

4.3 Zone Substation Supply Capacity

CLN is a summer peaking substation with a forecast maximum demand growth rate averaging 4.3% per annum over the next 10-year period. The growth in demand is predominately driven by the significant expansion of residential and commercial development in Melbourne's southeast growth corridor.

The zone substation summer maximum demand recorded in 2019/20 was 73.4 MVA. The forecast summer maximum demand is given in Table 6.

Table 6: Forecast Summer Maximum Demand

Probability of Exceedance (POE)	Forecast Summer Maximum Demand 2022/23 (MVA)	Forecast Summer Maximum Demand 2026/27 (MVA)
50%	80.9	97.2
10%	94.3	113.5

Figure 3 shows the forecast maximum demand and supply capacities (cyclic ratings) of CLN. It is important to note that demand already exceeds the N-1 cyclic rating, which is the station's supply capacity when one transformer out of service, and is forecast to exceed the station's N rating, which is the station's supply capacity with all assets in service, during the 2021-25 EDPR period.

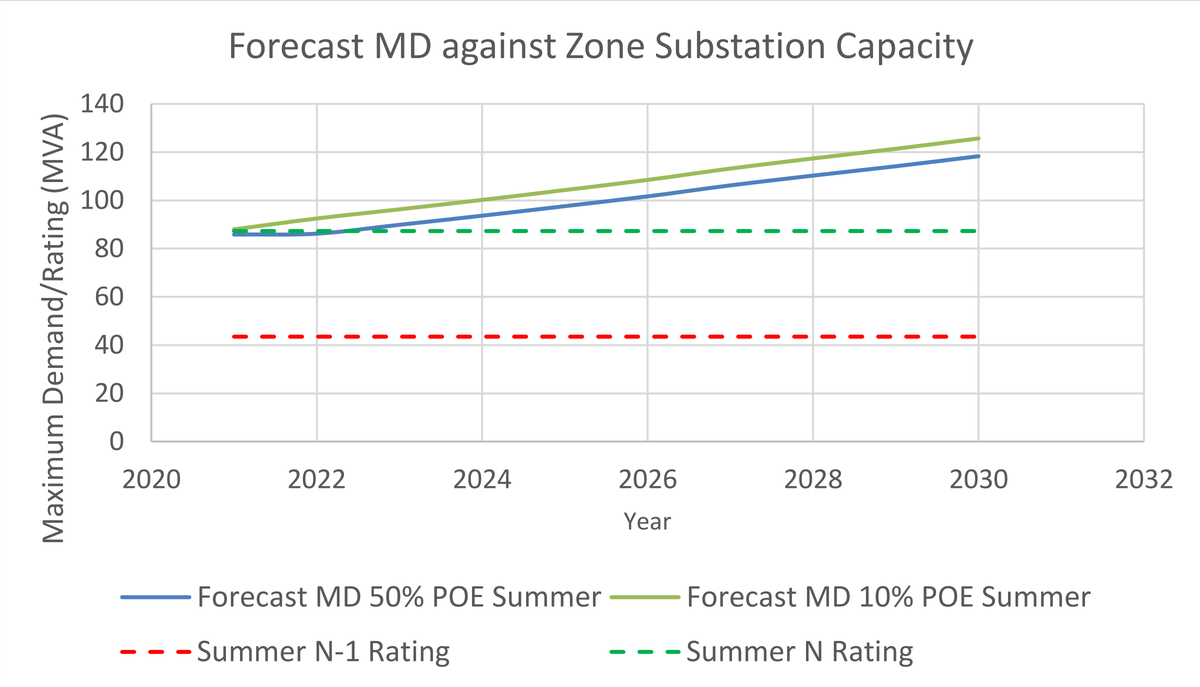

Figure 3: CLN forecast maximum demand and supply capacity

4.4 Load Duration Curves

The zone substation load duration curves that feed into the risk-cost assessment model are derived from historical actual demands between:

- 1 October 2019 and 31 March 2020 for the summer 50% probability of exceedance (POE) curves;
- 1 April 2020 and 30 September 2020 for the winter 50% POE curves;
- 1 October 2019 and 31 March 2020 for the summer 10% POE curves; and
- 1 April 2020 and 30 September 2020 for the winter 10% POE curves.

The historical hourly demands are separated by season and unitised based on the recorded maximum demand within that season (summer and winter) and time period. This allows the load duration curve to be scaled according to the seasonal forecast maximum demand for each year of the assessment period.

The 50% POE unitised load duration for CLN is presented in Figure 4, and the 10% POE unitised load duration for CLN is presented in Figure 5.

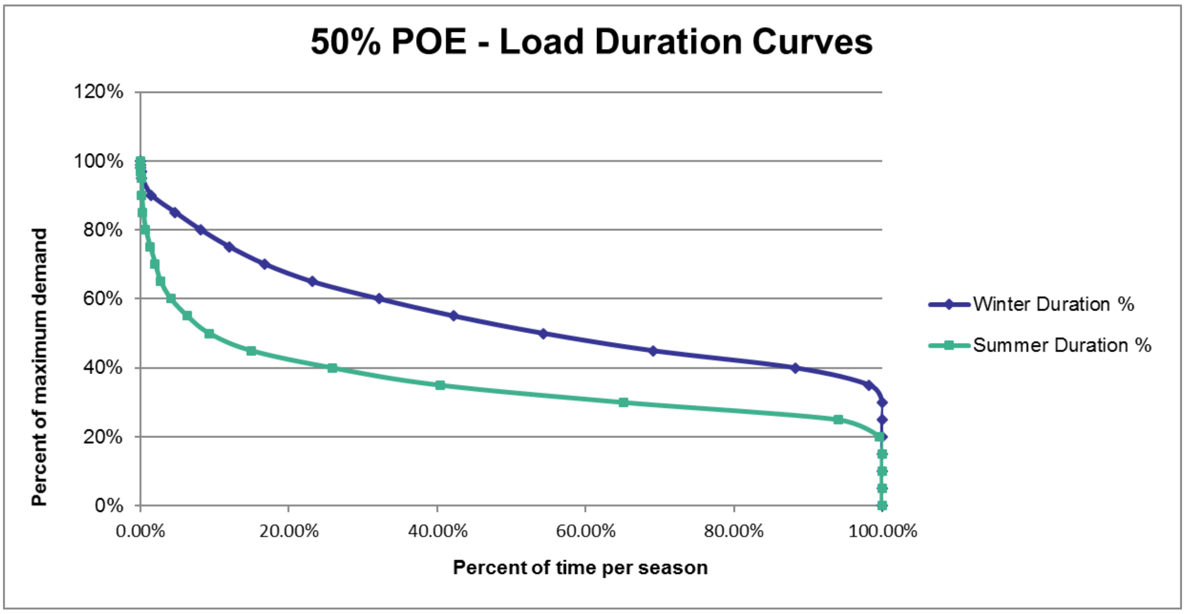

Figure 4: CLN 50% load duration curves

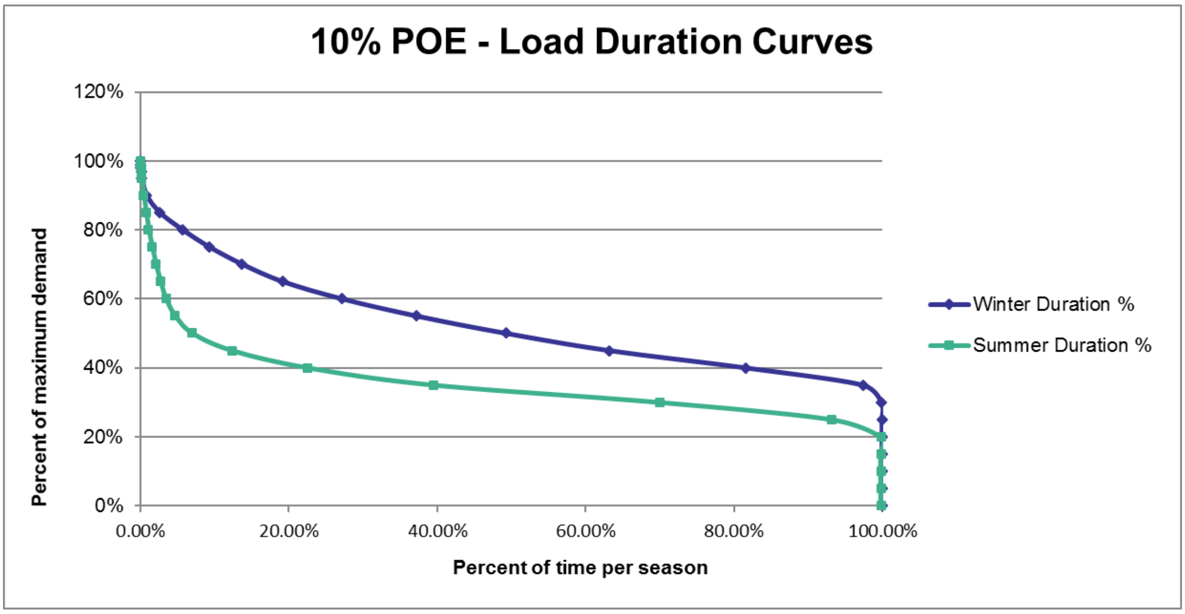

Figure 5: CLN 10% POE load duration curves

4.5 Feeder Circuit Supply Capacity

In addition to the zone substation constraints, supply capacity from CLN is also limited at the feeder circuit level, where electricity demand growth is forecast to exceed the capacity of two CLN feeder circuits during the 2021 to 2026 regulatory period.

Table 7 presents the rating and annual forecast maximum demand of the 22 kV feeder circuits supplied from CLN. The ratings presented are the continuous summer feeder circuit ratings, and the forecast maximum demand levels represent a 50% probability of exceedance forecast. The shaded cells show when the feeder demand is forecast to exceed the feeder circuit rating.

Table 7: Forecast utilisation of CLN feeders

Feeder	Rating (A)	Forecast Maximum Demand (A)						
		2023	2024	2025	2026	2027	2028	2029
CLN11	375	335	341	346	351	357	363	368
CLN12	335	295	314	333	352	370	387	404
CLN13	344	313	334	354	375	395	413	430
CLN14	325	299	307	315	323	334	342	349
CLN21	358	281	287	293	299	305	310	316
CLN22	375	55	78	100	121	144	166	189
CLN23	323	199	208	218	227	235	244	252
CLN24	360	47	53	58	64	70	75	81

4.6 Load Transfer Capacity

CLN is surrounded by Cranbourne (CRE) and Hampton Park (HPK) zone substations in the west, Berwick North (BWN) Zone Substation in the North and Officer (OFR) Zone Substation in East.

CLN has multiple feeder interconnections with its neighbouring zone substations, as outlined in Table 8, which have potential to provide emergency load transfer during periods of limited or insufficient supply capacity.

Table 8: CLN feeder interconnections to adjacent zone substations

CLN Feeder	Adjacent Connecting Feeders	Connection Point Location relative to CLN
CLN11	CRE23, CRE33, HPK11	West
CLN12	CRE33, CRE32	West
CLN13	CRE33	South West
CLN14	OFR21, BWN12	North East
CLN21	HPK14, HPK22	North West
CLN22	CRE33	South West
CLN23	None	
CLN24	None	

Table 9 presents the rating and forecast maximum demand of feeder circuits supplied from zone substations adjacent to CLN, and that have normally open connection points to CLN feeders. The ratings presented are the continuous summer feeder circuit ratings, and the forecast maximum demand levels represent a 50% probability of exceedance forecast. The shaded cells show when the feeder demand is forecast to exceed the feeder circuit rating.

Table 9: Rating and demand of feeders connecting to CLN

Feeder	Rating (A)	Forecast Maximum Demand (A)						
		2023	2024	2025	2026	2027	2028	2029
BWN12	312	294	295	296	298	300	301	301
CRE23	360	229	232	233	234	236	239	243
CRE32	360	226	229	231	234	236	237	239

Feeder	Rating (A)	Forecast Maximum Demand (A)						
		2023	2024	2025	2026	2027	2028	2029
CRE33	335	245	256	263	271	277	281	285
HPK11	293	291	294	296	298	300	302	305
HPK14	330	243	248	252	255	257	260	262
HPK22	311	262	265	268	272	276	278	281
OFR21	375	368	387	404	421	440	461	482

Based on the feeder circuit connections to adjacent zone substations, and other relevant limitations, the emergency load transfer capacity away from CLN is 26.5 MVA in 2021/22, reducing to 18.7 MVA by 2029/30, as presented in Table 9.

Table 9: Emergency load transfer capacity away from CLN

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Forecast emergency load transfer capacity (MVA)	26.5	25.4	24.3	23.3	22.3	21.3	20.4	19.6	18.7	17.9

4.7 Station Configuration Supply Risk

The configuration of CLN means that failure of some 22kV and 66kV circuit breakers will result in an immediate loss of supply from CLN until the failed equipment can be switched out, isolated and the station supplies restored. The resultant supply outage would be for an estimated duration of two hours, which is the time typically required by operators to travel to site and manually re-configure circuits to isolate the failed equipment and sequentially restore supply to customers.

Table 10 lists the estimated bus outage consequence factors for each major type of equipment based on the substation layout.

Table 10: CLN Bus Outage Consequence Factors

Equipment	Estimated Bus Outage Consequence
Transformer	0%
22 kV circuit breaker	50%
66 kV circuit breaker	50%
22 kV current transformer	50%
66 kV current transformer	50%
22 kV voltage transformer	0%
66 kV voltage transformer	0%

4.8 Investments Impacting Customer Supply Arrangements

This section outlines planned and committed investments that are expected to impact the customer supply arrangements in the area Clyde North supply area.

4.8.1 Zone Substation Feeder Works

AusNet Services has recently completed two new 22 kV feeder installations, connecting to CLN. There are now no spare circuit breakers at CLN, and one of the circuit breakers has been used to connect two feeder lines in an arrangement known as piggy-back.

While this arrangement allowed both new feeders to be established before existing feeders were loaded above their thermal capacity, piggy-back feeder connections are undesirable, and only ever done as a temporary arrangement, because they result in poorer reliability due to the increased consequence of an outage associated with the higher load and number of customers connected to the single feeder exit circuit breaker.

Maintaining long term customer reliability at the feeder level relies on the establishment of a third 22 kV switchboard at CLN in the near future.

4.8.2 Critical Peak Demand Tariff

In 2011, AusNet Services introduced the critical peak demand (CPD) tariff for large customers. This tariff is part of the standard tariff structure that applies to all large business customers, which is defined as those having an expected annual energy consumption of 160 MWh or more.

This tariff structure gives customers the opportunity to minimise electricity consumption, or seek alternative supply sources, between 3pm and 7pm Australian Eastern Daylight Time (AEDT) on the five CPD days nominated by AusNet Services between 1 December and 31 March each year.

For customers on this tariff, AusNet Services calculates their average peak demand across the five CPD days, and this forms the basis of the ‘demand critical peak’ component of their tariff for the next 12 months. By reducing their demand on the nominated CPD days, customers have the opportunity to reduce their energy costs while assisting AusNet Services to manage supply risks in the local area.

Demand reduction responses in the CLN supply area have proven relatively strong on CPD nominated days, suggesting there are customers in the area that are price responsive and may be willing to provide firm demand response action via a network support contract. There are 65 large customers supplied from CLN. However, it is estimated that up to 90% of the demand response achieved thus far has been delivered by only six customers, four of which are already engaged by AusNet Services to provide network support demand management services.

While large customers are available to offset the demand, particularly throughout the middle of day, their contribution to the zone substation peak, and therefore their ability to reduce the zone substation peak demand, is diminished because their demand requirements are typically somewhat reduced by the time the zone substation peak evening peak arrives.

4.8.3 Network Support Contracts

AusNet Services currently contracts 1,863 kW of demand management network support services in the CLN zone substation supply area. These network support services are provided by four large customers located on feeder CLN11. The contracts were established to help manage supply risks associated with feeder circuit loading levels on CLN11 and also contribute to reducing the zone substation loading at peak demand times.

Demand management network support services are renegotiated on an annual basis to ensure their continued need and contracted level of support is appropriate.

5 Credible options

5.1 Risk-Cost Model Overview

This section outlines the potential options that have been considered to address the identified need, and summarises the key works and costs associated with implementing these options. In subsequent analysis some of these options have been found not to be credible, but are nevertheless included here for completeness.

The following options were considered in seeking to address the risks at CLN:

1. Do nothing (counterfactual);
2. Large customer demand management network support;
3. Residential battery network support;
4. Embedded generation network support;
5. Network reconfiguration;
6. Installation of a third transformer installation at CLN;
7. Installation of a third transformer and a new 22 kV switch room at CLN; and
8. Hybrid of Options 4 & 5 - by contracting with an embedded generation provider and transferring load from CLN to neighbouring zone substations.

In May 2021, we published a non-network options report in relation to the identified need at CLN and invited submissions from non-network proponents in order to explore potential non-network solutions. We received two submissions in response to our non-network options report, one of which was confidential and therefore cannot be summarised in this report. The second submission was received after the closing date for submissions and was an 'expression of interest', rather than a detailed response to the non-network options report.

Following a detailed review of both submissions, we concluded that there are no credible non-network options that are capable of addressing the identified need at CLN. As a consequence, Options 2, 3, 4 and 8 were no longer considered credible options. For completeness, the remainder of this section discusses each of the 8 options listed above in turn.

5.2 Option 1 – Do nothing (counterfactual)

The Do Nothing (counterfactual) option assumes that AusNet Services would not undertake any investment, outside of the normal operational and maintenance processes. Under this option, increasing supply risk would be managed by increased levels of involuntary load reduction.

The Do Nothing (counterfactual) option establishes the base level of risk, and provides a basis for comparing potential options. Although the Do Nothing option has the lowest direct investment costs, it will typically involve much higher asset performance and supply risks compared to the other options.

5.3 Option 2 – Large customer demand reduction network support

This option is to contract large customers capable of providing demand management network support services, by reducing their load in response to an AusNet Services instruction.

In assessing the feasibility of engaging demand management services to address the identified service level risk, large customers in the supply area were identified, their historical response to critical peak demand (CPD) days was assessed, and how their load levels align to the zone substation daily and peak demand periods was considered. On that basis, this option assumes 3.0 MW of demand management network support is contracted to help mitigate the identified service level risks.

A key purpose of the non-network options report was to engage with prospective service providers regarding the cost of non-network services, so that the viability of this option could be assessed. As already noted, we received two submissions from non-network proponents. On the basis of further detailed analysis, we concluded that neither response constituted a credible option. On that basis, option 2 is no longer considered credible and is not considered further in this FPAR.

5.4 Option 3 – Residential battery network support

This option is to contract with a non-network aggregator for residential battery discharge, in response to an instruction from AusNet Services. Although the physical support comes from customer installed batteries discharging into the network to offset demand, network support contracts would actually be between AusNet Services and network support aggregators, rather than directly with residential customers.

As noted in relation to Option 2, a key purpose of the non-network options report was to engage with prospective service providers regarding the viability of this option. As already noted, no credible non-network solutions were identified from the two submissions to our non-network options report. On that basis, this option is no longer considered credible and is not considered further in this FPAR.

5.5 Option 4 – Embedded generation network support

This option is to contract with an embedded generator to provide network support services in response to an AusNet Services request. The assessed network support capacity is 10 MW which, based on the average forecast growth in maximum demand over the period, could potentially delay a network solution by three to four years.

The feasibility of this option also depended on non-network proponents responding to our non-network options report. As already noted, no credible non-network solutions were identified from the two submissions to our non-network options report. On that basis, this option is no longer considered credible and is not considered further in this FPAR.

5.6 Option 5 – Network reconfiguration

This option investigates the ability of the network to support load transfers from CLN to adjacent zone substations, in order to reduce the load on the CLN 66/22kV transformers. It does not require any additional capital expenditure to implement. CLN has a number of feeder interconnections with its neighbouring zone substations, as outlined in Table 11.

Table 11: CLN feeder interconnections to adjacent zone substations

From Feeder	To Feeder	Connection Point location – Figure 1
CLN11	CRE23, CRE33 or HPK11	West
CLN12	CRE33 or CRE32	West
CLN13	CRE33	South West
CLN14	OFR21 or BWN12	North East
CLN21	HPK14 or HPK22	North West
CLN22	CRE33	South West
CLN23	None	
CLN24	None	

The forecast loading on the CLN feeders and neighbouring zone substation feeders are presented in Table 12.

Table 12: Feeder summer 50% POE maximum demand forecasts

Feeder	Rating (A)	Forecast (A)						
		2023	2024	2025	2026	2027	2028	2029
BWN12	312	294	295	296	298	300	301	301
CLN11	375	335	341	346	351	357	363	368
CLN12	335	295	314	333	352	370	387	404
CLN13	344	313	334	354	375	395	413	430
CLN14	325	299	307	315	323	334	342	349
CLN21	358	281	287	293	299	305	310	316
CLN22	375	55	78	100	121	144	166	189
CLN23	323	199	208	218	227	235	244	252
CLN24	360	47	53	58	64	70	75	81
CRE23	360	229	232	233	234	236	239	243
CRE32	360	226	229	231	234	236	237	239
CRE33	335	245	256	263	271	277	281	285
HPK11	293	291	294	296	298	300	302	305
HPK14	330	243	248	252	255	257	260	262
HPK22	311	262	265	268	272	276	278	281
OFR21	375	368	387	404	421	440	461	482

As per the feeder circuit maximum demand forecasts presented in Table 12, many of the feeders connecting CLN to its neighbouring zone substation are heavily loaded and, as detailed in the following sections, incapable of being reconfigured to permanently transfer sufficient load from CLN.

CRE23

The spare capacity available in CRE23 is 131 A in summer 2021 and reduces to 117 A by summer 2027. However, due to the existing feeder geography and configuration majority of the CLN11 feeder has to be transferred to CRE23 and it is more than 120 A thus over-loading CRE23 feeder. Thus, it is not possible to off-load CLN11 to CRE23.

The three neighbouring feeders to CRE23 (CRE31, CRE32 and CRE33) are running close to their ratings and the spare capacity available in CRE23 will be required for contingencies in CRE feeders. This spare capacity will also be used in contingencies in heavily loaded CLN feeders.

CRE33

CRE33 has an average forecast growth of 10 A per year. The spare capacity available in CRE33 is 90 A in 2021 and is forecast to reduce to 50 A by 2027.

Lang Lang (LLG) zone substation is a single transformer and single 66 kV line substation. During outage events it is supplied from CRE zone substation, via CRE33, and other neighbouring zone substations. The spare capacity in CRE33 is therefore required to support LLG zone substation can cannot be utilised to permanently off-load CLN via feeder reconfigurations and load transfers.

HPK11

HPK11 feeder is forecast to operate at the rating during next six-year period. The feeder will be risk managed during the six-year period, and therefore cannot be utilised to permanently off-load CLN via feeder reconfigurations and load transfers.

HPK14

The spare capacity available in HKP14 is 87 A in summer 2021 and is forecast to reduce to 68 A by summer 2027. Due to the existing HPK14 and CLN21 feeder configurations, the minimum load that could be transferred from CLN21 to HPK14 is greater than 120 A. Transferring this amount of load is not feasible because it would overload HPK14. It is therefore not feasible to off-load CLN21 to HPK14.

Additionally, the two neighbouring feeders to HPK14, HPK11 and HPK22, are operating close to their ratings and the spare capacity available in HPK14 is required to provide back-up supply to under contingencies conditions.

HPK22

HPK22 feeder is forecast to operate close to its rating during the next six-year period. It therefore has no spare capacity to off-load CLN via feeder reconfigurations and load transfers.

OFR21

OFR21 is situated in the south east growth corridor and is forecast to be loaded above its rating by 2022. This feeder therefore has insufficient capacity available to permanently off-load CLN via feeder reconfigurations and load transfers.

5.7 Option 6 – Installation of a third transformer at CLN

This option is to install a third 66/22 kV 20/33 MVA transformer at CLN. Installation of a third transformer would increase the zone substation nameplate rating from 66 MVA to 99 MVA, the ‘N’ cyclic rating from 87.3 MVA to 130.1 MVA and the ‘N-1’ cyclic rating from 43.5 MVA to 87.3 MVA.

Although this option would sufficiently increase the capacity of the ZSS to meet forecast demand in the CLN supply area, it does not adequately address the capacity constraints at the feeder-circuit-level. This option does not fully address the identified need and is not regarded as a credible option and is not considered further in this FPAR.

5.8 Option 7 – Installation of a third transformer and a new switch room at CLN

This option is to install a third 66/22 kV 20/33 MVA transformer and a third 22 kV switchboard at CLN. Installation of a third transformer would increase the zone substation nameplate rating from 66 MVA to 99 MVA, the ‘N’ cyclic rating from 87.3 MVA to 130.1 MVA and the ‘N-1’ cyclic rating from 43.5 MVA to 87.3 MVA. This increased capacity would be sufficient to reliably supply the forecast maximum demand at the zone substation level.

With installation of a third 22 kV switchboard, this option would provide new 22 kV feeder exits from CLN and will thereby enable installation of the new CLN feeders planned during the 2021 to 2026 regulatory period.

This option has an estimated total capital cost of $13.3 million (nominal), which includes overheads and finance costs. The direct capital costs are $11.1 million (nominal).

5.9 Hybrid of Options 4 & 5 – by contracting with an embedded generation provider and transferring load from CLN to neighbouring zone substations

This option considered whether a combined network and non-network solution could address the identified need. As already noted in relation to Option 4, no credible non-network solutions were identified from the two responses to our non-network options report. On that basis, this option is also no longer credible and is not considered further in this FPAR.

6 Economic assessment of the credible options

6.1 Market benefits

The regulatory investment test for distribution requires the RIT-D proponent to consider whether each credible option provides the classes of market benefits described in clause 5.17.1(c)(4) of the NER. To address this requirement, the table below discusses our approach to each of the market benefits listed in clause 5.17.1(c)(4) in assessing the credible options to address the identified need at CLN.

Table 13: Analysis of Market Benefits

Class of Market Benefit	Analysis
(i) changes in voluntary load curtailment;	The options are not expected to lead to changes in voluntary load curtailment.
(ii) changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers;	The options are expected to have an impact on involuntary load shedding, although the identified need relates to asset condition. The cost benefit analysis will therefore consider the impact of each option on load shedding. AusNet Services applies probabilistic planning techniques to assess the expected cost of unserved energy for each option. This market benefit is quantified in section 6.4.
(iii) changes in costs for parties, other than the RIT-D proponent, due to differences in: *(A) the timing of new plant;* *(B) capital costs; and* *(C) the operating and maintenance costs;*	There is no impact on other parties.
(iv) differences in the timing of expenditure;	This project will not result in changes in the timing of other expenditure.
(v) changes in load transfer capacity and the capacity of Embedded Generators to take up load;	This project will not impact on the capacity of Embedded Generators to take up load.
(vi) any additional option value (where this value has not already been included in the other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the National Electricity Market;	This project will not impact the option value in respect to likely future investment needs of the NEM.
(vii) changes in electrical energy losses; and	This project will not result in changes to electrical energy losses.
(viii) any other class of market benefit determined to be relevant by the AER.	We do not consider any other class of market benefit as relevant to the selection of the preferred option.

6.2 Methodology

The purpose of this section is to provide a high level explanation of our methodology for identifying the preferred option. As a general principle, it is important that the methodology takes account of the identified need and the factors that are likely to influence the choice of the preferred option. As such, the methodology is not a 'one size fits all' approach, but one that is tailored for the particular circumstances under consideration.

The identified need for this project can be described in terms of supply risk, where an asset failure may lead to a loss of supply to customers.

In monetise supply risk, we adopt a probabilistic planning methodology which considers the likelihood and severity of critical network conditions and outages. The expected annual cost to customers associated with supply risk is calculated by multiplying the expected unserved energy (the expected energy not supplied based on the probability of the supply constraint occurring in a year) by the value of customer reliability (VCR).

The purpose of the cost benefit analysis that underpins the RIT-D assessment is to determine whether there is a cost effective option to mitigate the supply risk (or 'risk-cost'). In order to be cost effective, the reduction in the aggregate risk-cost that an option is expected to provide must exceed the cost of implementing that option. The preferred option provides greatest expected net benefit, expressed in present value terms.

In the absence of remedial action, Figure 6 shows how the risk-cost will typically increase as the risk of asset failure and energy at risk increase over time. The optimal timing of the preferred option occurs when the annualised capital cost of that option (or the operating cost for a non-network option) is equal to the risk-cost.

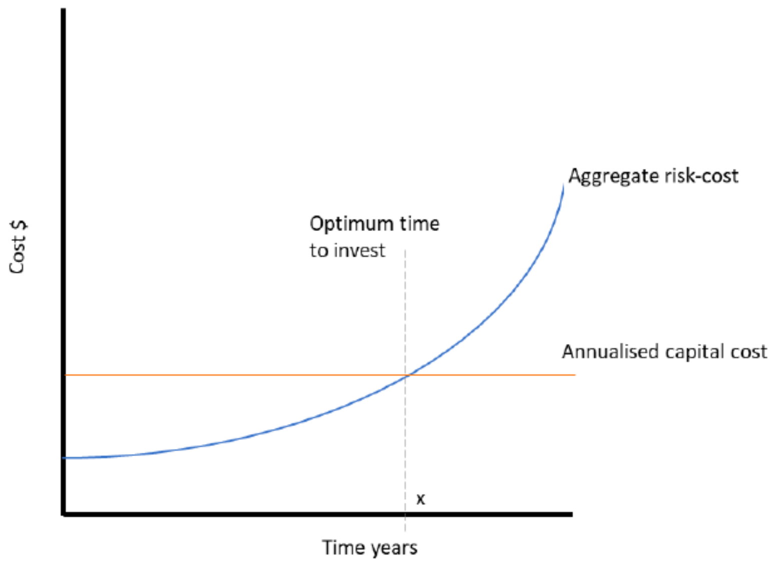

Figure 6: Increasing risk-cost over time and optimal project timing

In effect, the preferred option delivers the lowest total cost to customers, which is the sum of the cost of implementing that option and any residual risk-cost. The identification of the preferred option is complicated by the fact that the future is uncertain and that various input parameters are 'best estimates' rather than known values. As a consequence, the RIT-D analysis must be conducted in the face of uncertainty.

To address uncertainty in our assessment of the credible options, we use sensitivity analysis and scenario analysis in our cost benefit assessment. As recommended by the AER's application guidelines, we use sensitivity analysis to assist in determining an appropriate set of reasonable scenarios.[1] The relationship between sensitivity analysis and scenarios is best explained by the AER's practice note:[2]

> *Scenarios should be constructed to express a reasonable set of internally consistent possible future states of the world. Each scenario enables consideration of the prudent and efficient investment option (or set of options) that deliver the service levels required in that scenario at the most efficient long run service cost consistent with the National Electricity Objective (NEO).*
>
> *Sensitivity analysis enables understanding of which input values (variables) are the most determinant in selecting the preferred option (or set of options). By understanding the sensitivity of the options model to the input values a greater focus can be placed on refining and evidencing the key input values. Generally the more sensitive the model output is to a key input value, the more value there is in refining and evidencing the associated assumptions and choice of value.*
>
> *Scenario and sensitivity analyses should be used to demonstrate that the proposed solution is robust for a reasonable range of futures and for a reasonable range of positive and negative variations in key input assumptions. NSPs should explain the rationale for the selection of the key input assumptions and the variations applied to the analysis.*

In applying sensitivities and scenarios to our cost benefit assessment, we have regard to the particular circumstances to ensure that the approach is appropriate. Where our analysis shows that an option is clearly preferred, we will not undertake further testing. This approach is consistent with clause 5.17.1(c)(2) of the Rules, which states that the RIT–D must not require a level of analysis that is disproportionate to the scale and likely impact of each credible option considered.

In preparing the RIT-D, we have also had regard to AEMO's 2021 Inputs, Assumptions and Scenarios Report and its draft 2022 Integrated System Plan (ISP). We note that the scenarios adopted by AEMO are focused particularly on the matters that are relevant to major transmission investments, rather than distribution investments of the type considered in this report. Accordingly, we have adopted an approach that is appropriate to the particular circumstances described in this report relating to the identified need and the credible options.

6.3 Key variables and assumptions

Table 14 below lists the key variables and assumptions applied in the economic assessment, which are essential inputs to our methodology described above. The table also sets out the upper and lower bounds of the range of forecasts adopted for each of these variables. As explained above, the lower bound and upper bound estimates are used to undertake sensitivity testing and scenario analysis. The detailed results of this modelling is provided in the next section.

Table 14: Key variables and assumptions ($M)

Variable / assumption	Lower bound	Central estimate	Upper bound
Demand forecasts	5% reduction in central estimate of annual growth rate	Average annual growth rate of 4.3%	5% increase in central estimate of annual growth rate

[1] AER, Application guidelines, Regulatory investment test for distribution, December 2018, page 42.

[2] AER, Asset replacement planning, January 2019, page 36.

Variable / assumption	Lower bound	Central estimate	Upper bound
Cost of involuntary supply interruption	25% reduction in central estimate	Value of Customer Reliability (VCR) of $35,314per MWh[3]	25% increase in central estimate
Safety cost	Central Estimate	Value of statistical life of $4.5 million[4]	Central estimate
Safety cost Disproportionate Factor	Central estimate	Factor of 3	Central estimate
Option cost	15% reduction in central estimate	In-house cost estimates using detailed and high-level project scopes	15% increase in central estimate
Real discount rate per annum[5]	2.0%	5.5%	7.5%
Probability of asset failure	25% reduction in central estimate	Historical asset performance data, plus forecasts based on condition monitoring and CBRM modelling	25% increase in central estimate

Source: CLN_V4.0_Economic_Model-Hybrid Option_24-12-2021 V2

6.4 Net present value analysis

The economic analysis presented below allows comparison of the economic cost and benefits of each option to rank the options and to determine the optimal timing of the preferred option. It quantifies the capital costs and the cost of the residual risk for each option, to determine a total cost for each option. The net economic benefit for each credible option is the total cost associated with that option minus the costs of the 'Business as Usual' option.

As each of the credible options involves the replacement of existing assets, we have assumed that the operating cost for each option is unchanged from the 'Business as Usual' option. For the purpose of this RIT-D, we consider this approach to be a reasonable working assumption. The capital cost for each option has been described in section 5 of this FPAR.

We present our analysis as follows:

- Section 6.4.1 presents the NPV analysis using central estimates; and
- Section 6.4.2 presents the sensitivity testing and scenarios analysis.

3 Calculated using the latest VCR estimates for each sector.

4 Best Practice Regulation Guidance Note Value of statistical life, December 2014, escalated.

5 The discount rates are consistent with AEMO's 2021 Inputs, Assumptions and Scenarios Report.

6.4.1 Present value analysis using central estimates

Table 15 presents the annualised net economic benefit of each credible option for each year and highlights the option with the highest net economic benefit, assuming the central estimates for the key variables presented in the previous section. For each option, we have selected the optimal timing or indicated for some options that the solution will not deliver a net benefit over the study period.

It should be noted that a residual risk-cost and benefit also applies for each option, which captures the costs and benefits beyond 2031. We have not shown the residual costs and benefits for each option in the table below, but it is considered in our PV analysis which is reported later in this section.

Table 15: Annualised net economic benefit ($M)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Option 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Option 2	This option is no longer considered credible, as explained in section 5.3.									
Option 3	This option is no longer considered credible, as explained in section 5.4.									
Option 4	This option is no longer considered credible, as explained in section 5.5.									
Option 5	0.07	0.30	0.62	1.03	1.49	2.07	2.84	3.65	4.64	5.68
Option 6	This option is not considered to be credible, as explained in section 5.7.									
Option 7	0.00	0.00	0.86	2.48	5.04	8.54	13.37	19.43	26.93	36.47
Option 8	This option is no longer considered credible, as explained in section 5.9.									

Source: CLN_V4.0_Economic_Model-Hybrid Option_24-12-2021 V2

As shown in the table above, Options 2, 3, 4, 6 and 8 are not credible options and therefore are not considered further in this RIT-D assessment. Of the remaining two credible options, Option 5 delivers a net benefit sooner than Option 7, but is comprehensively outperformed by Option 7 from 2025 onwards. By 2031, Option 7 is expected to provide a net benefit in that year of $36.37 million compared to $5.68 million for Option 5.

While the above table is useful in understanding how the options compare with one another in the early years following their implementation, the analysis required by the RIT-D must consider the relative performance of the credible options over the life of the asset. Accordingly, the following table shows that the present values for each option over its life, using our central estimates, based on the optimal timing for each option.

Table 16: Net economic benefit ($M)

	PV of risk reduction Benefit	PV of Option costs	PV of net economic benefit
Option 1	0.0	0.0	0.0
Option 2	Not a credible option		
Option 3	Not a credible option		
Option 4	Not a credible option		
Option 5	66.82	0.00	66.82
Option 6	Not a credible option		
Option 7	414.81	9.64	405.15
Option 8	Not a credible option		

Source: CLN_V4.0_Economic_Model-Hybrid Option_24-12-2021 V2

The present value analysis shown in Table 16 shows that Option 7 is preferred to the remaining credible option and the 'Business as Usual' option because it delivers the highest expected net benefit over the expected life of the investment, based on our central estimates.

6.4.2 Sensitivity testing and scenarios analysis

As explained in section 6.2, we undertake sensitivity testing to examine how the net benefit for each option would be affected if certain parameters were varied. In this instance, we considered variations in the risk of asset failure; demand; the cost of each option; and the discount rate. The results of this analysis is presented below.

Table 17: Net benefit - sensitivity testing ($M)

	High asset failure	Low asset failure	High demand	Low demand	High option cost	Low option cost	High discount rate	Low discount rate
Option 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Option 2	Not a credible option							
Option 3	Not a credible option							
Option 4	Not a credible option							
Option 5	74.22	62.66	72.51	61.26	66.82	66.82	47.68	66.82
Option 6	Not a credible option							
Option 7	453.50	380.71	487.11	333.68	403.73	406.62	282.02	405.17
Option 8	Not a credible option							

Source: CLN_V4.0_Economic_Model-Hybrid Option_24-12-2021 V2

The sensitivity analysis shows that Option 7 continues to deliver substantial net benefits against each of these changes in parameter assumptions, which provides strong assurance that the project delivers a net benefit across a broad range of different parameter inputs. To test our results further, we have adopted four scenarios, as set out below.

Table 18: Definition of reasonable scenarios

Scenario	Probability of failure	Option Cost	Forecast Demand	VCR	Discount rate
Central Case	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate
Low demand	Central estimate	Central estimate	Lower bound	Central estimate	Central estimate
Weak economic growth	Central estimate	Lower bound	Lower bound	Central estimate	Lower bound
High demand	Central estimate	Upper bound	Upper bound	Central estimate	Upper bound

Table 19 below provides a brief description of each scenario.

Table 19: Guide to scenarios

Scenario	Description
Central Case	This scenario adopts the central estimate for each variable in the economic assessment. It represents the most likely outcome.
Low demand	This scenario represents low demand driven by an increase in distributed energy resources. We have retained the other parameters at their central estimates, noting that the scenario is not driven by weak economic growth.
Weak economic growth	This scenario reflects weak economic growth, possibly as a result of the continuing impact of COVID-19. It has lower costs of delivering the option, lower demand and a lower discount rate
High demand	This scenario represents an economic rebound and continuing supply side issues. It is characterised by higher costs of delivering the option, higher demand and an upper bound discount rate.

Table 20: Net benefit for each scenario ($M)

	Central case	Low demand	Weak economic growth	High demand
Option 1	0.0	0.0	0.0	0.0
Option 2	Not a credible option			
Option 3	Not a credible option			
Option 4	Not a credible option			
Option 5	66.82	61.26	125.69	52.05
Option 6	Not a credible option			
Option 7	405.17	333.68	710.98	339.83
Option 8	Not a credible option			

Source: CLN_V4.0_Economic_Model-Hybrid Option_24-12-2021 V2

On the basis of this scenario analysis, Option 7 is preferred to the other options, as it delivers a higher net economic benefit across each of the four scenarios.

6.5 Preferred option

The results of our cost benefit analysis is that Option 7 is the preferred option, which involves the following works:

- Install a third 66/22 kV 20/33 MVA transformer and a third 22 kV switchboard at CLN.
- Installation of a third transformer would increase the zone substation nameplate rating from 66 MVA to 99 MVA, the 'N' cyclic rating from 87.3 MVA to 130.1 MVA and the 'N-1' cyclic rating from 43.5 MVA to 87.3 MVA.

This option is expected to maximise the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

In relation to the optimal timing of the preferred option, our modelling indicates that the project should be delivered by 2025 on the basis of our central estimates. Further details on the scope of works are provided in the Appendix.

6.6 Capital and operating costs of the preferred option

The direct capital expenditure for the preferred option (less Management Reserve) is $11.1 million (nominal), as shown in the table below. The estimated total capital cost is $13.3 million (nominal), which includes overheads and finance costs.

Table 21: Summary of capital expenditure requirements, $'000, nominal

	2022	2023	2024	**2025**	**Total**
Design	100	895.3	-	23.6	**1,018.9**
Internal Labour	-	269.9	465.8	36.0	**771.7**
Materials	-	3,951.6	-	-	**3951.6**
Plans & Equipment	-	109.3	353.0	-	**462.3**
Contracts	-	981.2	3,169.2	-	**4,150.4**
Risk	-	326.7	333.2	56.6	**716.5**
Management Reserve	-	189.5	123.4	3.3	**316.2**
Total capital expenditure	**100**	**6,723.3**	**4,444.5**	**119.5**	**11,387.6**

Source: AusNet Services, DD-0011571 – CLN 3rd Transformer and Switch room – Business Case

The operating expenditure associated with this option will relate to the on-going inspection and maintenance of the assets. Our assessment is that a reasonable estimate of the annual operating expenditure is approximately 1.2% of the direct capital cost of the asset, which equates to $140k per annum.

In relation to the timetable for completing these works, we expect construction to commence by January 2023, with commission readiness completed by April 2024. The project is expected to reach completion by 31 May 2024.

7 Satisfaction of the RIT-D

In accordance with clause 5.17.4(j)(11)(iv) of the Rules, we certify that the proposed option satisfies the regulatory investment test for distribution. The table below shows how each of the Rules requirements have been met by the relevant sections of this report. As no submissions were received in response to the DPAR, 5.17.4(r)(1)(ii) is not applicable for this FPAR.

Table 22: Compliance with regulatory requirements

Requirement			Section
5.17.4(j) The draft project assessment report must include the following[6]:			
(1)		a description of the identified need for the investment;	Section 3.
(2)		the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, reasons that the RIT-D proponent considers reliability corrective action is necessary);	Section 4.
(3)		if applicable, a summary of, and commentary on, the submissions on the non-network options report;	Section 5.1.
(4)		a description of each credible option assessed;	Section 5.
(5)		where a Distribution Network Service Provider has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit for each credible option;	Section 6.1, Table 13 and section 6.4.
(6)		a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure;	Sections 5 and 6.4.
(7)		a detailed description of the methodologies used in quantifying each class of cost and market benefit;	Section 6.2.
(8)		where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option;	Section 6.1, Table 13.
(9)		the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Section 6.4.
(10)		the identification of the proposed preferred option;	Sections 1.2 and 6.5.
(11)		for the proposed preferred option, the RIT-D proponent must provide:	
	(i)	details of the technical characteristics;	Appendix.
	(ii)	the estimated construction timetable and commissioning date (where relevant);	Section 6.6.

[6] Although this provision refers to the draft project assessment report, it is applicable to this FPAR by virtue of clause 5.17.4(r)(1).

Requirement	Section
(iii) the indicative capital and operating cost (where relevant);	Section 6.6.
(iv) a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and	Section 7, including this table.
(v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent;	Not applicable.
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	Section 1.3.

Appendix - Technical Characteristics

Scope of work

The scope of this project is to:

- Install 3rd 66/22kV (20/33MVA) Transformer
- Install 2nd 22kV Urban Switchroom
- Extend the switchyard to the property's western boundary
- Upgrade the existing 2 x 100kVA station service transformers with 315kVA
- Split CLN11 piggyback feeder into the new switchroom
- Remove CB 'A'
- Extend the 66kV ring bus including:
- 2 x 66kV DTCB
- 5 x 66kV RDBs

In addition to these works, other tasks to be undertaken include:

- Upgrade the existing environmental system
- Relocate the existing amenities building
- Install relevant protection and control equipment

The proposed post-augmentation single line diagram of the proposed preferred option is set out below.

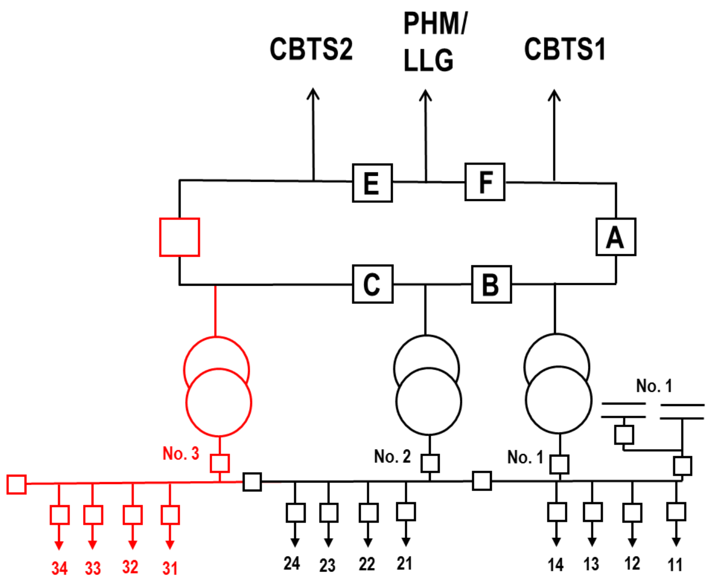

Figure 7: Post Augmentation Single Line Diagram of CLN

As shown in red, the key option works include establishing a new 66/22 kV transformer, a 66 kV circuit breaker to facilitate connection of the new transformer, and a new 22 kV switchboard to facilitate connection of the new transformer and separation of the temporarily piggy-backed feeders that are currently in the construction phase.