CitiPower | RIT-D final project assessment report: Brunswick area supply

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Contents

1 Summary

This final project assessment report has been prepared in accordance with the Regulatory Investment Test for Distribution (**RIT-D**) requirements of the National Electricity Rules (**the Rules**)[1].

On 2 August 2018, CitiPower published a draft project assessment report, the purpose of which was to consult on the credible options to address the identified need—namely, the increasing risks to safety and reliability of supply caused by the deterioration of the 80 year old assets at Brunswick (**C**) zone substation. The preparation of that report followed our publication of a non-network options report in March 2018. No submissions were received in response to the March 2018 non-network options report. Similarly, no submissions were received in response to our August 2018 draft project assessment report.

In preparing this final project assessment report, we have updated the capital and operating cost estimates of all credible options.

The analysis presented in this final report confirms the findings of our draft report. Our preferred option is to upgrade our West Brunswick (**WB**) zone substation so that zone substation C can first be offloaded to zone substation WB at 6.6 kV, and then decommissioned. Our economic assessment indicates that the optimum time to complete this work is 2021, at a revised estimated total direct capital cost of $14.86 million (in 2018 present value terms). This equates to a total direct capital cost of $17.04 million (in undiscounted 2018 dollars). We note that our revised estimated direct capital cost is $0.76 million lower that the estimate (of $15.62 million in present value terms) we provided in the draft project assessment report.

1 Version 115 of the Rules, clause 5.17.4.

2 Background

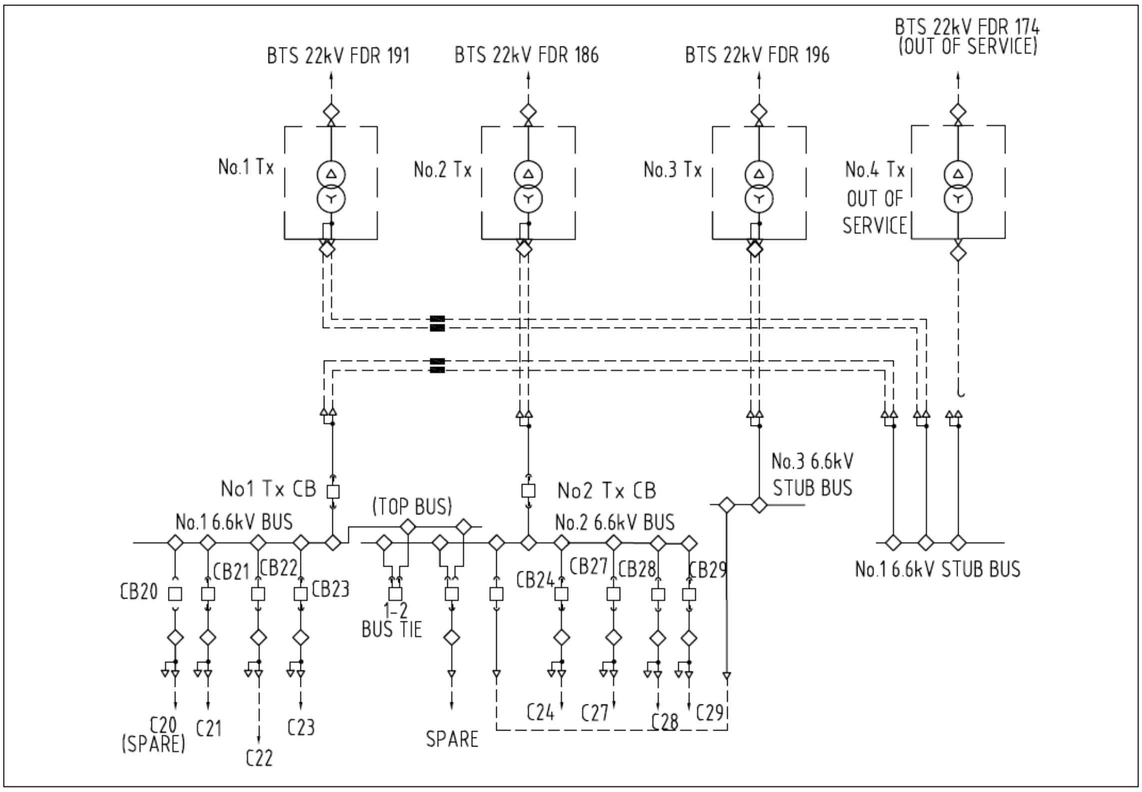
2.1 Zone substation configurations

Zone substation C was commissioned in 1938 as a 22 kV/6.6 kV station with two 7.5 MVA (name plate rating) transformers supplied via underground 22 kV sub-transmission cables from Brunswick Terminal Station (**BTS**). Two additional 7.5 MVA (name plate rating) transformers were installed in 1940 and 1942. One of the transformers has since been retired due to poor condition and as such the station N rating is based on three transformers.

There is no 22 kV switching or 22 kV bus tie meaning that the 22 kV cables from BTS are directly connected to each of the transformers.

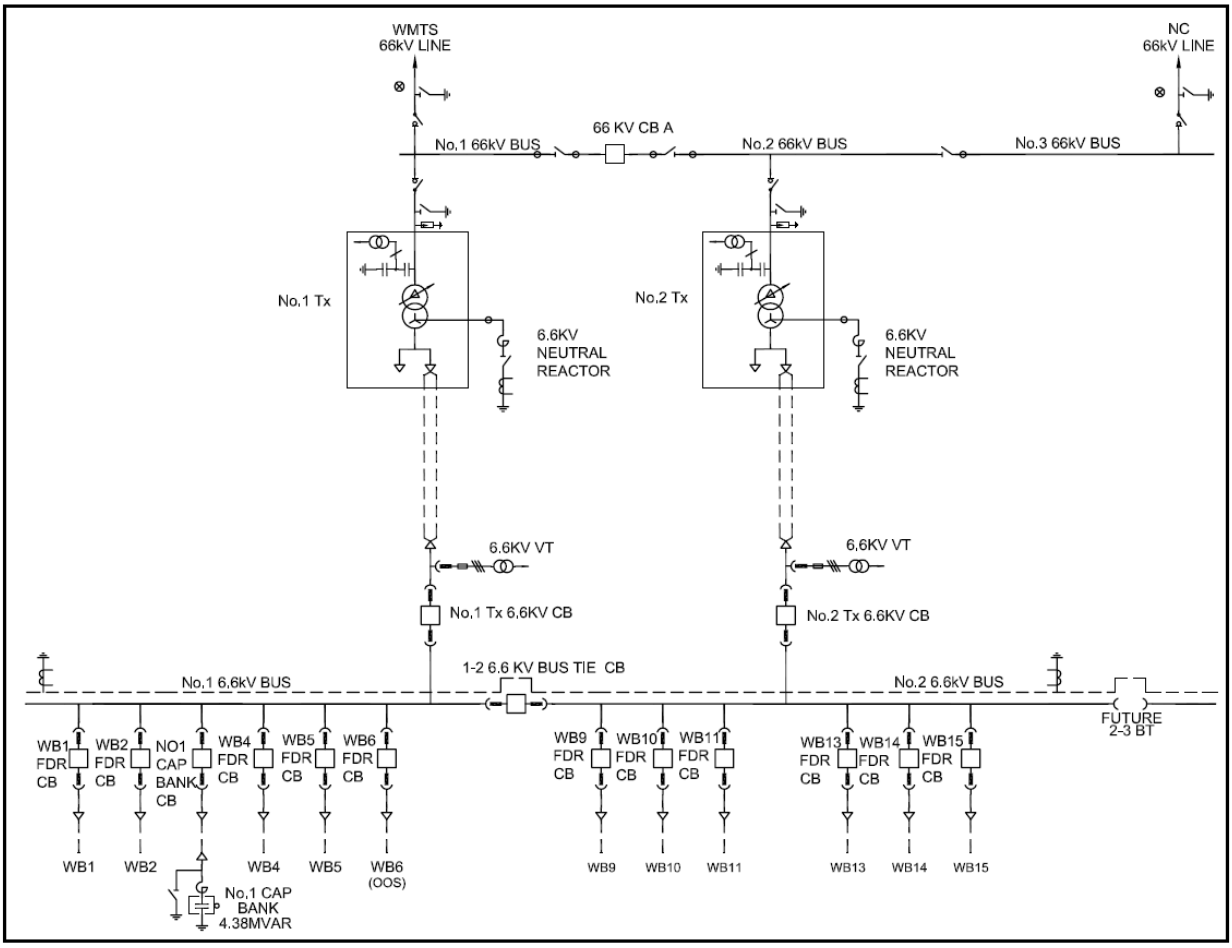
The transformers do not have on-load tap changers and the secondary sides are connected to two 6.6 kV busses supplying eight feeders. Figure 2.1 shows a single line diagram of the current arrangements at zone substation C.

Figure 2.1 Zone substation C single line diagram



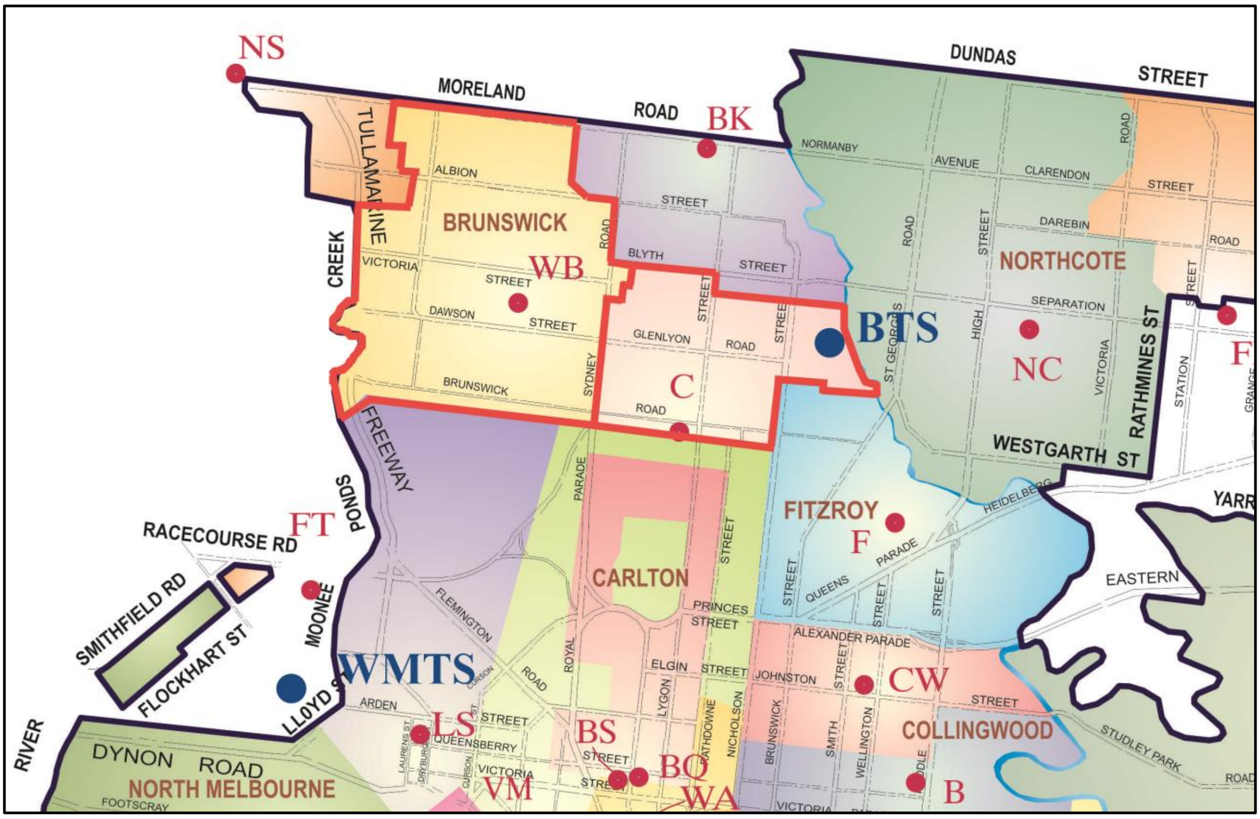
Zone substation WB was commissioned in 1965 as a 66kV/6.6kV substation with the installation of two 20/30 MVA 66kV/11kV/6.6kV dual ratio transformers. The station is supplied via overhead 66kV sub-transmission lines from West Melbourne Terminal Station (**WMTS**). Figure 2.2 shows a single line diagram of the current arrangements at zone substation WB. Zone substation WB is designed to accommodate third transformer and a third bus.

Figure 2.2 Zone substation WB single line diagram



Zone substation C is located at 62 Brunswick Road, Brunswick and supplies electricity to 5,200 customers including 4,769 domestic, 385 commercial and 46 industrial customers. Zone substation WB is located at 334 Albert Street, Brunswick and supplies electricity to 12,340 customers including 11,216 domestic, 983 commercial and 141 industrial customers. Figure 2.3 shows the geographic areas supplied by these zone substations.

Figure 2.3: Geographical area supplied by zone substation C and WB



2.2 Historical and forecast demand

Traditionally zone substation C has been a winter peaking zone substation, however in recent years the station has experienced its peak in summer, with residential customers being the main contributors to the demand. The historical and forecast demand for summer and winter is shown in figure 2.4 and figure 2.5 respectively.

Figure 2.4 Zone substation C summer actual and forecast demand

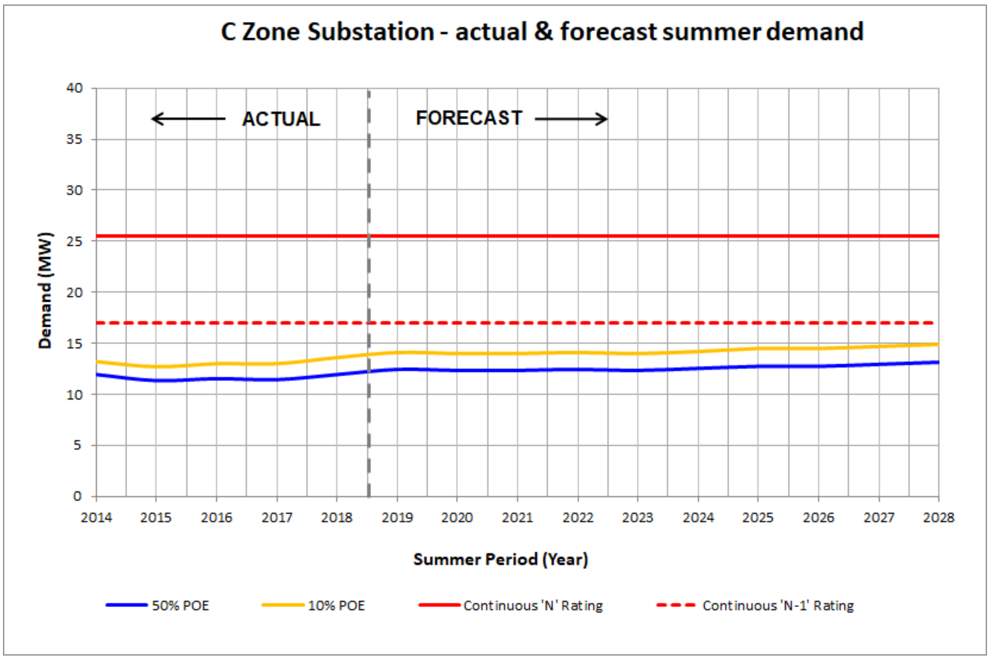
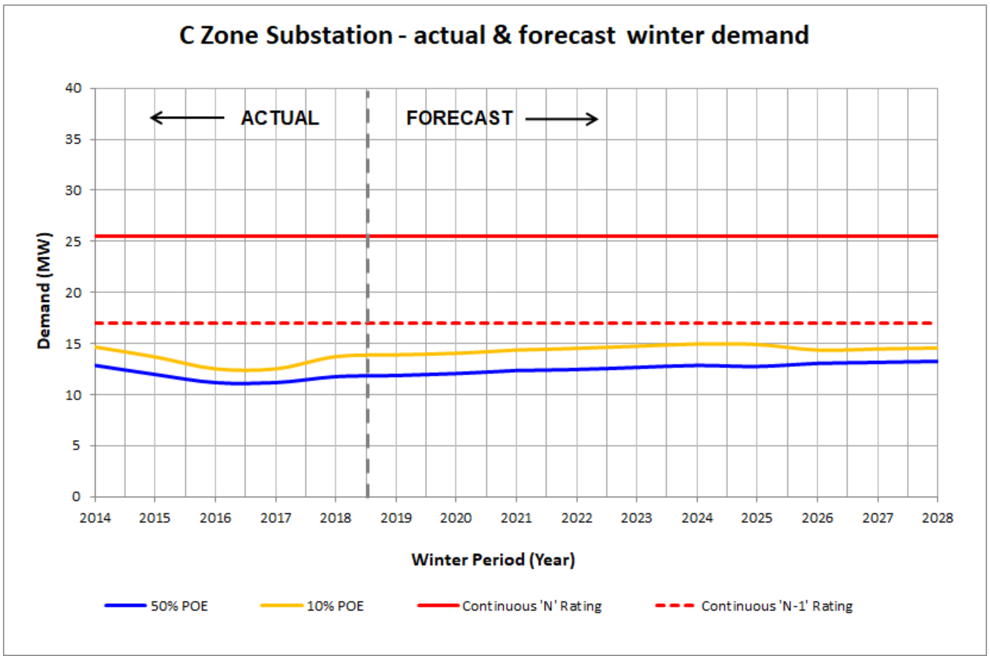


Figure 2.5 Zone substation C winter actual and forecast demand



2.3 Load transfer capacity to adjacent zone substations

The load transfer capability between zone substation C and nearby WB, Fitzroy (**F**) and Brunswick (**BK**) zone substations is limited. During peak demand an estimated maximum transfer capacity of 4.0 MVA is available via 6.6 kV links to these adjacent zone substations as an operational response to partially mitigate the impact of an outage at zone substation C.

3 Identified need

3.1 Overview of the need for investment

Load at zone substation C is not forecast to exceed the station N-1 rating of 17 MVA in the next 10 years and there is no load at risk at the substation today. However, multiple assets including transformers, circuit breakers and auxiliary equipment are at the end of their service lives, and the substation is supplied by old paper lead cables which are difficult to repair should a fault occur. These assets present an increasing operational and safety risk if they continue in service into the future.

As there is limited load transfer capability between zone substation C and the nearby WB, F and BK zone substations, there is a risk that should a major outage occur at zone substation C, customers will be left without electricity for a sustained period as we will be unable to restore supply to all customers until repairs are made. In addition, in the event of a catastrophic failure of a transformer or circuit breaker, there is a risk of serious injury to staff and damage to plant and buildings.

The identified need, therefore, is to address the increasing risks to safety and reliability of supply associated with the deterioration of the assets at zone substation C. Addressing this need ensures we continue to comply with the following:

- section 98 of the Electricity Safety Act[2]
- clauses 3.1 and 5.2 of the Victorian Electricity Distribution Code.[3]

Section 3.2 below provides an overview of our approach to assessing asset condition and risk. Sections 3.3 to 3.5 then provide further information on the condition of the plant at zone substation C, and the need to address the risks associated with the deteriorating condition of these assets.

3.2 Our approach to assessing asset condition and risk

We apply the condition based risk management (**CBRM**) methodology to certain plant-based asset classes, namely transformers and HV circuit breakers. The CBRM model is an asset risk assessment algorithm that considers a range of inputs including:

- asset condition assessment data, such as transformer oil condition
- environmental factors, such as whether the assets are located indoors or outdoors, or coastal areas
- operating factors, such as the load utilisation, frequency of use and load profiles that the asset is supplying.

These factors are combined to produce a health index for each asset in a range from 0 to 10, where 0 is a new asset and 10 represents end of life. The health index provides a means of comparing similar assets in terms of their probability of failure.

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[2] Under section 98 of the Electricity Industry Safety Act, CitiPower (as a major electricity company) must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable:

- the hazards and risks to the safety of any person arising from the supply network; and
- the hazards and risks of damage to the property of any person arising from the supply network.

[3] Clause 3.1 of the Victorian Electricity Distribution Code requires us to manage our assets in accordance with the principles of good asset management. Under this provision, we must, among other things, develop and implement plans for the management of our assets to minimise the risks associated with the failure or reduced performance of assets. Under clause 5.2, we are required to use best endeavours to meet customers' reasonable expectations of supply reliability.

We closely monitor assets with a health index in the range 5 to 7 to determine options for intervention, including replacement or retirement, in the context of energy at risk. Interventions are evaluated and planned when asset health index exceeds 5.5 and intervention is prioritised when asset health index exceeds 7.

A health index profile gives an immediate appreciation of the condition of all assets in a group and an understanding of the future condition of the assets.

As part of the CBRM process, the consequence of failure of the asset is also calculated. The consequence of failure consists of four elements:

- network performance
- safety
- financial
- environment.

The risk is calculated by combining the probability of failure of the asset and the consequence of failure of the asset. CBRM is used to calculate how the risk is likely to change in future years. In this way, the CBRM analysis provides:

- a preliminary indication of the likely optimum replacement time of an asset
- a foundation or starting point for further detailed economic assessment to determine the optimum timing of intervention action.

As already noted, the assets at zone substation C are aged and in poor condition. Our latest CBRM analysis indicates that the optimum year to retire the deteriorating assets at zone substation C is likely to be around 2021. The economic assessment set out in section 6 provides a detailed analysis of the optimum timing of action to address the identified need.

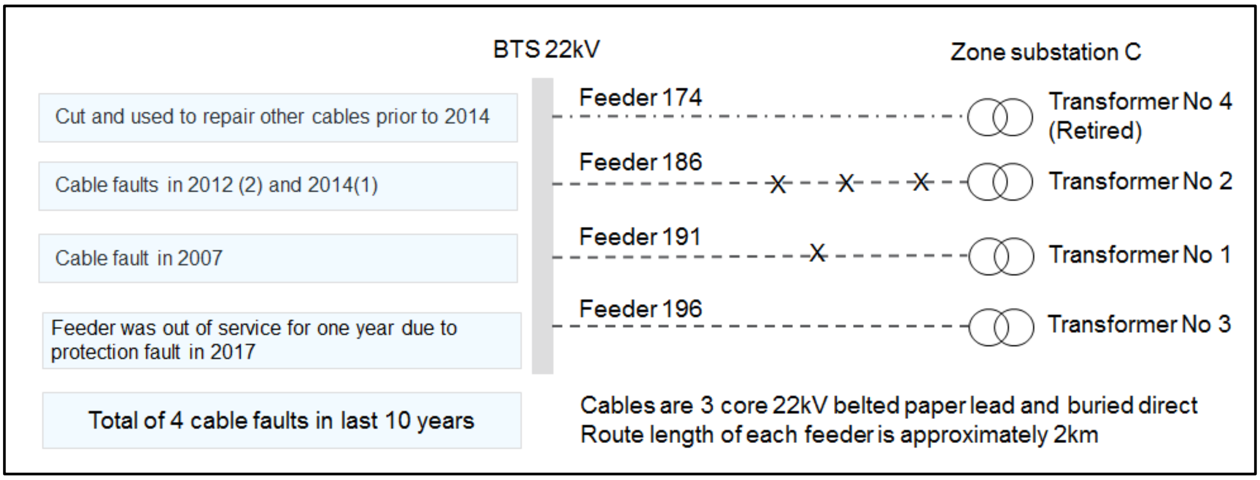
3.3 22 kV sub-transmission cables

The 22 kV cables supplying zone substation C from BTS are of the belted paper lead type construction and date back to the late 1930s (i.e. they are 80 years old).

The cables have experienced failures in recent years as shown in figure 3.1, with some occurring in cable sections rather than joints which indicates the cable itself is close to end of life. Ageing and embrittlement of the lead sheath is a significant factor in the determination of end of life for this type of cable construction. The original fourth cable (which has been out of service for many years) has been used to cross joint around several failures in the other three cables.

The cables are direct buried (i.e. not in conduits) and are not able to be replaced in situ.

Figure 3.1 Summary of BTS-C 22kV sub-transmission cable failures in the last 10 years



3.4 Transformers and HV switchgear

The CBRM analysis has determined that all three transformers currently have a health index of 7.0 (rising to 8.00 in 2021), with the HV switchgear currently having a health index of 6.05 (rising to 6.27 in 2021).

To efficiently manage the risks to safety, and reliability and security of supply associated with the deterioration of the transformers and HV switchgear at zone substation C, this plant should be retired by 2021.

Other considerations that are relevant to the timing of retirement of the assets at zone substation C include:

- one of the three transformers currently has an intermittent internal fault, posing a safety risk to personnel and other assets in the station. This fault is currently being monitored through additional inspections and condition assessments
- there are no firewalls separating the transformers from each other or from the building that houses other equipment such as 6.6 kV switchgear and protection equipment. This means that a catastrophic failure of any one transformer will result in damage to other transformers, the building and other assets in the substation
- there is no oil containment bund for the transformers. This means that any catastrophic fault in the transformers is likely to result in uncontrolled oil spillage
- due to the age of the HV circuit breakers, operational performance has declined. Slow operation of a circuit breaker during fault clearance may result in a full bus outage and loss of supply to half of the customers supplied from the substation
- the HV circuit breakers do not have motorised spring rewind. This means that an operator must attend the station to restore supply after any operation of the switchgear to clear a fault, delaying the restoration of supply to customers. Further, it means that modern measures to enhance reliability such as auto reclose cannot be utilised
- the HV switchboard is not arc fault contained or vented, therefore failure of the switchboard or any circuit breaker due to an internal fault poses a safety risk to personnel and other assets in the station
- any catastrophic failure of a transformer or circuit breaker may result in a full station outage
- spare parts are no longer available for aged major plant components. Any failure of a critical component requires reengineering of the part and further delays restoration of the asset into service.

3.5 Auxiliary equipment

The site has a significant number of aged mechanical protection relays and secondary equipment which is both limited in functionally and creates issues interfacing with the more modern relays protecting supply from BTS. This raises the risk of protection mal-operation leading to an increased frequency of transformer outages at zone substation C. This has already occurred in the past on feeder 196 (as shown in figure 3.1) which was out of service for 17 months from June 2016 to November 2017 due to a protection fault. The delay in restoration time was due to a lack of spares and difficulty in interfacing with BTS.

4 Description of options

This section describes the options, network and non-network, we considered to address the identified need.

4.1 Network options

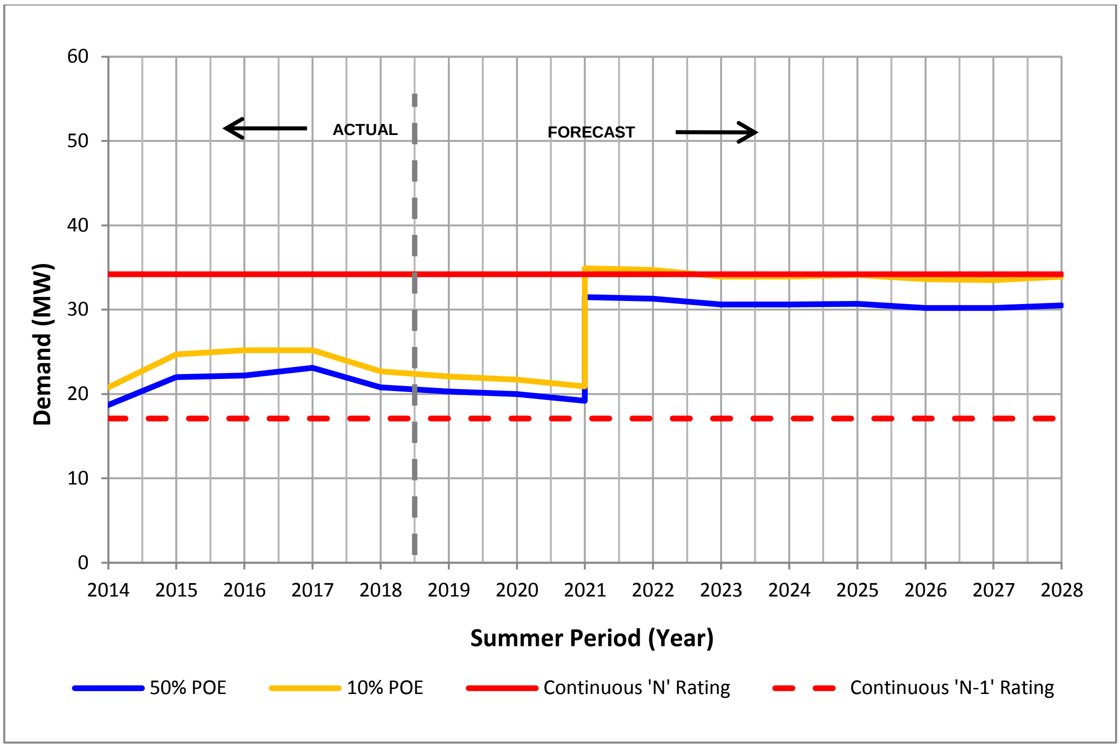
Table 4.1 provides a description of the credible network options that address the identified need. These options include a 'business as usual' option (option 0), where the existing assets at zone substation C are replaced on a 'like for like' basis as they individually reach the end of their service life (i.e. we replace 22 kV cables with new 22 kV cables, replace the transformers with same capacity units, replace switchboard and the auxiliary equipment with new units).

Table 4.1 Network options

Network option description	
Option 0	**Business as usual (like for like asset replacement)** The scope of work includes: • replace three 22kV cables from BTS to C with new 22kV cables • replace all three 7.5 MVA transformers at C with new 7.5 MVA transformers and install oil containment bunds and firewalls • replace switchboard with new switchboard • replace auxiliary equipment with new auxiliary equipment.
Option 1	**Offload C to WB at 6.6 kV** The scope of work includes: • install a third transformer (20/30 MVA), second 66 kV circuit breaker and a third 6.6 kV/11 kV bus at WB • install six additional 6.6 kV feeders at WB and augment three existing feeders to offload C by 13.2 MVA • install a 66 kV 4 ohm reactor on the 66 kV sub-transmission line from West Melbourne Terminal Station (**WMTS**) to WB to comply with the fault level requirements on the 6.6 kV secondary side when operating two transformers in parallel • decommission zone substation C. This option aligns with our strategy to replace the 22kV sub-transmission network with 66 kV.
Option 2	**Offload C to WB at 11 kV** The scope of work includes: • install a third transformer (20/30 MVA), second 66 kV circuit breaker and replace the existing 6.6 kV switchboard with a new 11 kV switchboard at WB • convert the C and WB 6.6 kV distribution network to 11 kV • install two additional 11 kV feeders at WB and augment three existing feeders to offload C by 13.2 MVA • decommission zone substation C. This option is similar in scope to option 1 but it involves converting existing 6.6 kV distribution feeders to 11 kV. This project aligns with our strategy to replace the 22 kV sub-transmission with 66 kV as well as upgrading the associated 6.6 kV distribution network to 11 kV.
Option 3	**Rebuild C** The scope of work includes: • install two 66 kV cables from WMTS-Northcote (NC) sub-transmission line, 66 kV bus structure, 66 kV circuit breaker, two transformers (20/27 MVA) and 6.6 kV switchboard at C • decommission existing transformers and switchgear at C. This option aligns with our strategy to replace the 22kV sub-transmission network with 66 kV. Also, this project will house the new 6.6 kV switchgear and auxiliary equipment in the existing 80 year old building.

Options 1 and 2 above require offloading load at zone substation C to WB. Zone substation WB is a summer peaking substation with residential customers being the main contributors to the peak demand. Zone substation WB historical and forecast demand for summer, including additional zone substation C load from 2021 onwards without installing third transformer at zone substation WB, is shown in Figure 4.1.

Figure 4.1 Zone substation WB summer actual and forecast, including additional zone substation C load without installing third transformer



The 10% probability of exceedance rating at zone substation WB with additional load from zone substation C is slightly over the station 'N' Rating. This necessitates installation of third transformer at zone substation WB.

In determining the size of the transformer that would be installed at WB under the two network options, we examined the possibility of installing a smaller transformer (to reduce capital costs). We found such an approach would not be economic because:

- it would require the installation of a smaller transformer than the existing ones at zone substation WB, resulting in uneven transformer loading that would lead to operational constraints and accelerated aging of the smaller transformer(s)
- it would necessitate the installation of a non-standard transformer, and this would lead to increased operation and maintenance costs, and higher total asset lifecycle costs.

Installation of a third 20/30MVA transformer at zone substation WB under the two network options has the added benefit of mitigating energy at risk forecasted to reach 179 MWh in 2018 (N-1 50% probability of exceedance).

Two other network options were also considered, but they were rejected as being infeasible. Details are provided in section 4.3 below.

4.2 Non-network options

On 1 March 2018, we published a non-network options report setting out the technical characteristics required of non-network options that would assist in addressing the identified need. Table 4.2 below provides a description of the non-network options that were identified in our non-network options report.

Table 4.2 Non-network options

Non-network option description	
Option 4	Interconnect 6.6 kV network to WB, BK and F, and utilise generation on our network to defer network investment. This option involves installation of local generation to defer the need for network investment by up to five years.
Option 5	Interconnect 6.6 kV network to WB, BK and F, and utilise demand management on our network to defer network investment. This option involves demand management by voluntary load reduction to defer the need for network investment by at least one year.
Option 6	Interconnect 6.6 kV network to WB, BK and F, and utilise a combination of demand management and generation on our network to defer network investment. This option involves using a mix of demand management and local generation to defer the need for network investment by at least one year.

No submissions or proposals were received in response to the non-network options report. Therefore, non-network options are not considered to be credible options, so they are not considered further in this final project assessment report.

4.3 Other network options considered but rejected

Table 4.3 describes other network options we considered, but rejected because they were either technically or economically infeasible.

Table 4.3 Other network options considered but rejected

Other network option description	
Option 7	The scope of this option includes the following work: • install 11 kV feeders from WB to C, and BK to C to offload C by 13.2 MVA • replace one transformer at BK • convert the C, WB and BK distribution network from 6.6kV to 11kV • decommission zone substation C. This option requires existing 6.6 kV / 11 kV dual rated switchgear at WB and BK to operate at 11 kV. Tests conducted of the HV switchboard at BK indicate that it is unsuitable to operate at 11 kV and as such this option was not pursued any further.
Option 8	Establish a new zone substation. The scope of this option includes the following work: • purchase a new site in the Brunswick area • install 66 kV sub-transmission lines, one 66 kV circuit breaker, two transformers, 6.6 kV distribution feeders and feeder ties to the distribution area served by C. Acquisition of an appropriate site to house the new zone substation in the densely populated Brunswick area was considered unlikely. This option is also subject to construction difficulties and disruption to the community due to the amount of feeder works. For these reasons this option was not evaluated any further.

5 Preliminary assessment of credible options

In this section we present the results of our preliminary assessment of the business as usual (like for like asset replacement) and three credible options set out in table 4.1. The purpose of this preliminary assessment is to identify the preferred option, which is then subject to more detailed economic evaluation.

In identifying the preferred option, the objective is to maximise net economic benefit[4]. Each of the credible options would deliver the same level of benefits, in terms of continuing to reliably supply load to the customers who are presently supplied from zone substation C. Therefore, the preferred option can be identified as the one that minimises total present value costs.

Table 5.1 shows the total present value costs of the business as usual option and the three credible options, calculated by applying a real pre-tax discount rate of 6%, and central (that is, most likely) forecasts of capital expenditure and whole-of-life operating expenditure.[5] Under this scenario, option 1 is preferred because it has the lowest present value total cost.

Table 5.1 Present value costs of credible options ($million, $2018)

Expenditure	Option 0	Option 1	Option 2	Option 3
Capital expenditure	28.62	14.86	22.43	26.55
Operating expenditure	0.09	0.18	0.18	0.71
Total cost	**28.71**	**15.04**	**22.61**	**27.26**

Consistent with the RIT-D guidelines, we also conducted sensitivity analysis on key assumptions and variables supporting our present value cost calculations. The key assumptions and variables that may affect the present value costs of the three credible options are:

- forecast capital costs
- forecast operating costs
- the discount rate applied.

We evaluated the present value costs of each option under different assumptions regarding capital costs, operating costs and discount rates. The results are shown in table 5.2.

4 Clause 5.17.1(b) of the Rules.

5 Paragraphs 16 and 17 of the RIT-D state: "The present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The discount rate used must be consistent with the cash flows that the RIT-D proponent is discounting. The lower boundary should be the regulated cost of capital." A discount rate in the range of 4% to 6% real (pre-tax) accords with these requirements.

Table 5.2 Present value costs of credible options ($million, $2018) under different cost forecasts and discount rates

Cost forecasts and discount rates applied	Option 0	Option 1	Option 2	Option 3
Central forecasts of costs; 6% real discount rate	28.71	15.04	22.61	27.26
120% of central cost forecasts; 6% real discount rate	34.47	18.04	27.14	32.72
120% of central cost forecasts; 4% real discount rate	36.28	18.96	28.72	34.46
80% of central cost forecasts; 6% real discount rate	22.98	12.03	18.09	21.81
80% of central cost forecasts; 4% real discount rate	24.08	12.64	19.15	22.97

Table 5.2 shows that the ranking of the options is unaffected by plausible variations from the central estimates of forecast capital and operating costs, and the discount rate applied. Under each combination of cost forecasts and discount rates, option 1 is the least-cost (or most efficient) option. This is to be expected, as the three credible options have very similar cash flow patterns and cost structures in terms of the mix of their operating and capital costs. The results of the analysis presented in table 5.2 show that under plausible variations from the central estimates of cost forecasts, and applying a plausible range of discount rates, option 1 is the most efficient option.

As shown in Table 5.1, option 1 has an estimated total direct capital cost of $14.86 million (in 2018 present value terms). This equates to a total direct capital cost of $17.04 million (in undiscounted 2018 dollars).

6 Detailed economic assessment

6.1 Methodology

Having identified option 1 as the most efficient option for addressing the identified need, it is necessary to conduct further detailed economic assessment to determine the timing of investment (if any) under option 1 that maximises net market benefits. This evaluation is carried out by comparing the annualised risk cost of the existing assets with the annualised cost of option 1.

The methodology we have applied in this assessment accords with the approach presented by the AER at a workshop on asset retirement planning, held at the AER's offices in Sydney on 20 October 2017. We have also had regard to the AER's draft industry practice application note on asset replacement planning which was published in September 2018.

Under the methodology, the annual risk cost of an asset (or group of assets) is calculated as the probability of asset failure multiplied by the likelihood of consequence of the asset failure multiplied by the consequence cost of the failure event.

To calculate the annual risk cost of the assets at zone substation C, we have modelled the eight failure modes listed in the table below.

Table 6.1 Modelled asset failure modes

Failure mode	Description
1	Catastrophic failure of a transformer (damages all three transformers)
2	Catastrophic failure of a CB (damages the whole bus)
3	Catastrophic failure of all 22kV sub-transmission cables (dig-in damaging all 3 sub-transmission cables)
4	Catastrophic VT failure of any of the 4 VTs on site (including stub bus VTs) leading to one of two buses failure
5	Major failure (disruptive failure) of any one transformer
6	Major failure (disruptive failure) of any one CB
7	Major failure of any one 22kV sub-transmission cable (cable failure due to end of life)
8	Major failure of VT (disruptive failure of VT)

The consequence costs for each failure mode were estimated in each of the following consequence areas:

- involuntary supply interruption
- safety (i.e. threat to human life)
- operating expenditure (principally for emergency generators)
- capital expenditure associated with the reinstatement or replacement of failed and damaged assets
- environmental costs such as oil spillage and site clean-up.

Annual asset failure and consequence probabilities were derived from historical asset performance data.

The probability-weighted cost of each failure mode was calculated, and these were summed to derive an estimate of the total expected annual cost.

6.2 Key variables and assumptions

Table 6.2 below lists the key variables and assumptions applied in the economic assessment. The table also sets out the upper and lower bounds of the range of forecasts adopted for each of these variables. We used these ranges to undertake sensitivity testing through scenario analysis, as explained in section 6.3.

Table 6.2 Variable ranges for sensitivity testing purposes

Variable / assumption	Lower bound	Central estimate	Upper bound
Demand forecasts	5% reduction in central estimate of annual growth rate	Average annual growth rate of 1.25%	5% increase in central estimate of annual growth rate
Cost of involuntary supply interruption	15% reduction in central estimate	Value of Customer Reliability (**VCR**) of $37,743 per MWh	15% increase in central estimate
Safety cost	Central estimate	Value of statistical life of $4.4 million (in March 2018 $)[6]	Central estimate
Safety cost Disproportionate Factor	Central estimate	Factor of 3	Central estimate
Emergency generation cost	20% reduction in central estimate	In-house estimate using high - level scopes	20% increase in central estimate
Network operating expenditure	20% reduction in central estimate	Incremental cost forecast based on asset operating and maintenance requirements	20% increase in central estimate
Network capital expenditure	20% reduction in central estimate	In-house cost estimates using detailed and high-level project scopes	20% increase in central estimate
Environmental costs	20% reduction in central estimate	Standard benchmarks and in-house estimates	20% increase in central estimate
Probability of asset failure	20% reduction in central estimate	Historical asset performance data, plus forecasts based on condition monitoring and CBRM modelling	20% increase in central estimate
Discount rate (pre-tax)	4% real, being the pre-tax equivalent of the regulated WACC	6% real, being consistent with a commercial discount rate (as per paragraph 16 of the RIT-D)	9% real

6 Department of the Prime Minister and Cabinet - Office of Best Practice Regulation, Best Practice Regulation Guidance Note: Value of statistical life, December 2014.

6.3 Scenarios adopted for sensitivity testing

The RIT-D requires sensitivity analysis to be undertaken through the modelling of reasonable scenarios.

We have developed four reasonable scenarios to test the sensitivity of the results of the economic assessment to plausible variations in the input values. Table 6.3 lists the input value for each variable in each scenario.

Table 6.3 Definition of reasonable scenarios

Scenario	Probability of failure	Capital expenditure	Forecast Demand	VCR	Operating expenditure	Environment cost	Discount rate
Central Scenario	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate
Scenario A	Lower bound	Upper bound	Lower bound	Lower bound	Lower bound	Lower bound	Upper bound
Scenario B	Lower bound	Lower bound	Lower bound	Lower bound	Lower bound	Lower bound	Lower bound
Scenario C	Upper bound	Upper bound	Upper bound	Upper bound	Upper bound	Upper bound	Upper bound
Scenario D	Upper bound	Lower bound	Upper bound	Upper bound	Upper bound	Upper bound	Lower bound

Table 6.4 below provides a brief description of each scenario.

Table 6.4 Guide to scenarios

Scenario	Description
Central scenario	This scenario adopts the central estimate for each variable in the economic assessment. It represents the most likely outcome.
Scenario A	This scenario represents a combination of variables that minimises the net market benefit of option 1 compared to the risk cost of assets.
Scenario B	This scenario defines a generic lower bound for the present value costs of both option 1 and the risk cost of assets.
Scenario C	This scenario defines a generic upper bound for the present value costs of both option 1 and the risk cost of assets.
Scenario D	This scenario represents a combination of variables that maximises the net market benefit of option 1 compared to the risk cost of assets.

6.4 Market benefits

The AER's Regulatory Test Guidelines explain that the RIT-D proponent is required to consider each class of market benefit, although it is not required to quantify the market benefit in the following circumstances[7]:

> *While a RIT-D proponent must consider each class of market benefit specified under cl. 5.17.1(c)(4) of the NER, a RIT-D proponent is not obligated to quantify the benefits that it considers to be immaterial or will not alter the selection of the preferred option. Likewise, a RIT-D proponent is not obligated to quantify market benefits for reliability driven projects.*

As explained in section 3.1, the identified need is to address the increasing risks to safety and reliability of supply associated with the deterioration of the assets at zone substation C. Addressing this need ensures we continue to comply with our obligations to provide safe and reliable services in accordance with section 98 of the Electricity Safety Act and clauses 3.1 and 5.2 of the Victorian Electricity Distribution Code. Accordingly, the identified need in this final project assessment report is for 'reliability corrective action' or a 'reliability driven project'. In accordance with the guidance set out above, therefore, we are not required to quantify the market benefits.

In accordance with the RIT-D[8], the table below explains how we have considered each of the market benefits listed in clause 5.17.1(c)(4) of the Rules for the preferred option, being option 1.

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7 Australian Energy Regulator, Regulatory investment test for distribution application guidelines, 18 September 2017, page 32.

8 Australian Energy Regulator, Regulatory investment test for distribution, 23 August 2013, paragraph 4.

Table 6.5: Consideration of market benefits

Market benefit	Consideration of this market benefit
(i) changes in voluntary load curtailment	The preferred option will not cause any 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 preferred option is expected to reduce network outages compared to a 'do nothing' option. This improvement reflects the reduced risk of asset failure by decommissioning aged, deteriorating assets.
(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;	The preferred option is not expected to give rise to changes in capital or operating costs for other parties.
(iv) differences in the timing of expenditure	The preferred option is not expected to have any impact on the timing of other expenditure.
(v) changes in load transfer capacity and the capacity of Embedded Generators to take up load;	The preferred option is not expected to affect load transfer capacity or 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;	The preferred option is not expected to affect the option value associated with future investment needs.
(vii) changes in electrical energy losses	The preferred option is not expected to materially affect electrical energy losses.
(viii) any other class of market benefit determined to be relevant by the AER	The preferred option is not expected to provide any other class of market benefit.

6.5 Results

6.5.1 Central Scenario

The figure below shows the annualised total cost of option 1 alongside the forecast annualised risk cost of assets under central estimate assumptions.

Figure 6.1 Results of economic assessment—central scenario

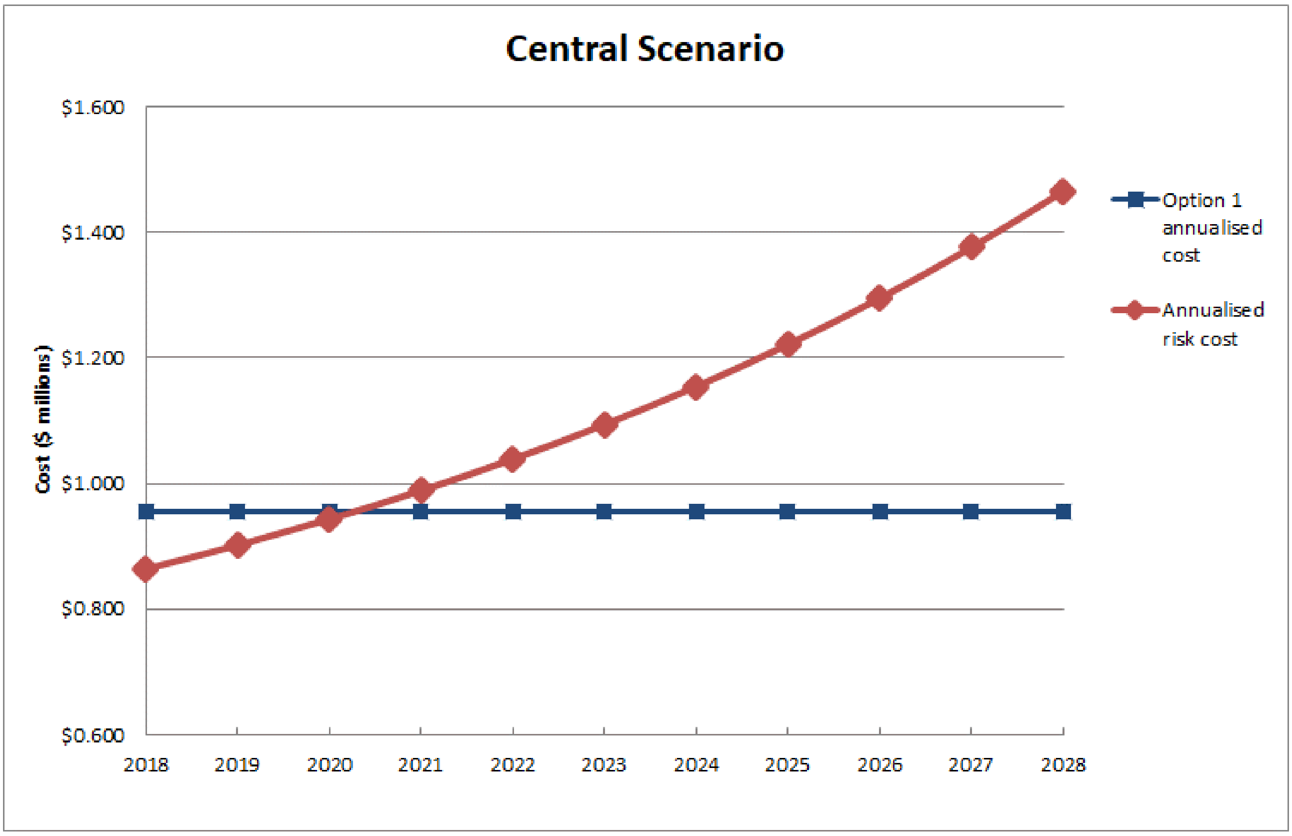
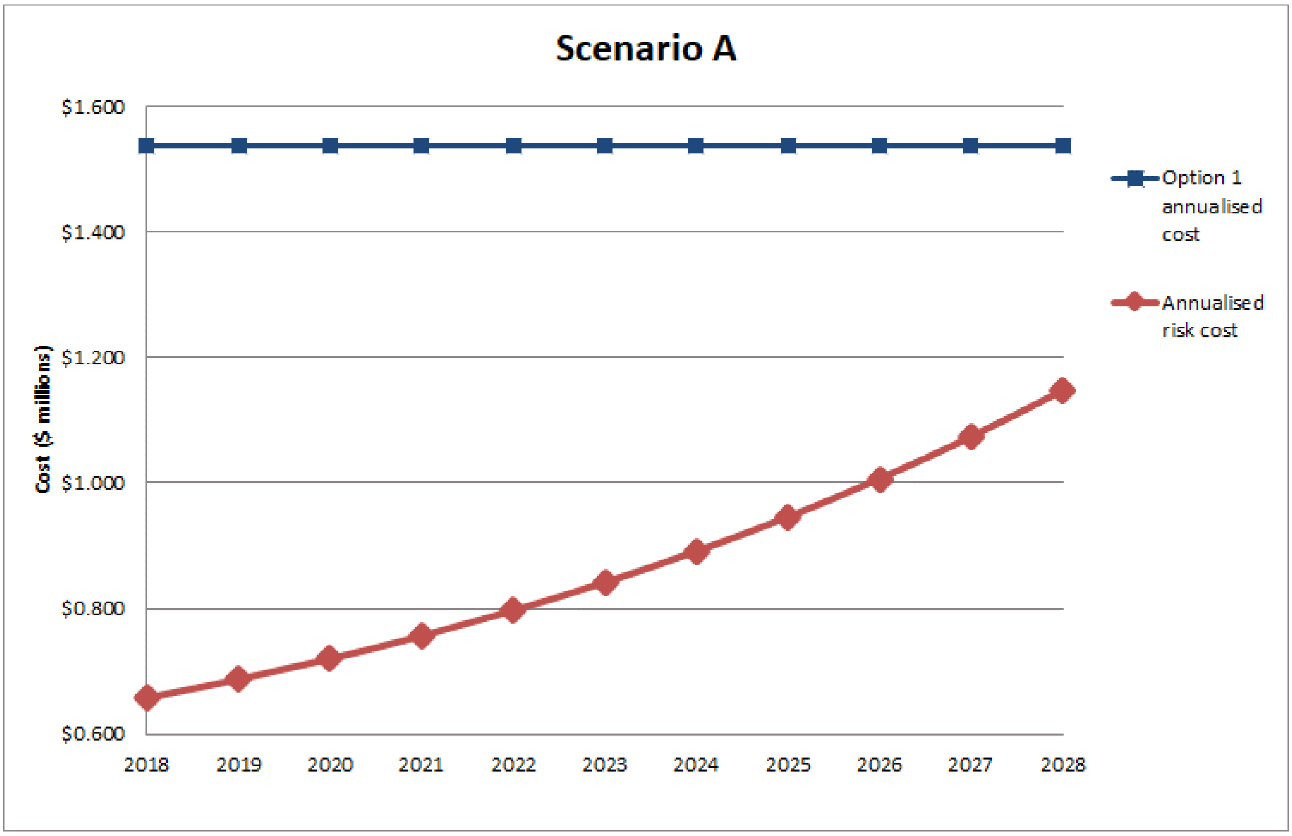


Figure 6.1 shows the annual expected cost of risk is forecast to increase. This reflects the forecast increase in the probability of asset failure as the existing assets remain in service and continue to deteriorate. The optimum time to invest in option 1 is when the annual cost of risk exceeds the annualised cost of option 1. Figure 6.1 shows that under central estimate input assumptions, between 2020 and 2021 is the optimum time for option 1 to be implemented to remove the risk.

6.5.2 Scenario A

The annual costs of option 1 and the risk cost of assets under scenario A are shown in figure 6.2 below.

Figure 6.2 Results of economic assessment—scenario A



As explained in table 6.4, scenario A represents a plausible combination of variables that minimises the net market benefit of option 1 compared to the risk cost of assets. Accordingly, in 2018 the annualised risk cost of assets is lower than it is under the central estimate assumptions, and it increases at a lower rate, reflecting the application of lower forecasts of asset failure probabilities.

The annualised cost of option 1 is higher than it is under the central estimate assumptions. This reflects the application of higher capital expenditure forecasts as well as the upper bound discount rate.

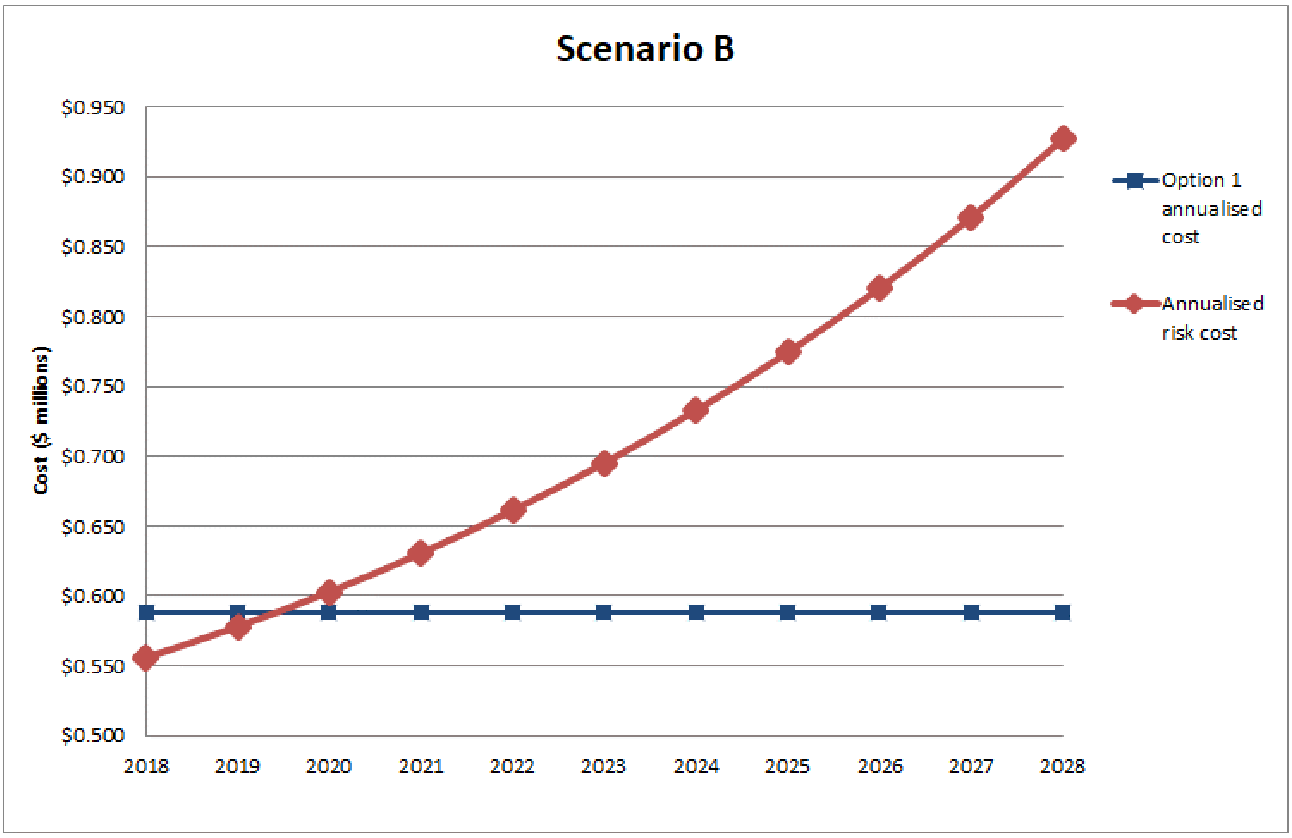
Figure 6.2 shows that under this combination of assumptions, the annualised risk cost of assets remains below that of option 1 for the period to 2028. This indicates that under this scenario, implementation of option 1 would be economic sometime after 2028.

It is noted that the combination of assumptions adopted for scenario A (shown in table 6.3) is considered much less likely to arise than the central forecasts that are applied in the central scenario.

6.5.3 Scenario B

The annual costs of option 1 and the risk cost of assets under scenario B are shown in figure 6.3 below.

Figure 6.3 Results of economic assessment—scenario B



Scenario B defines a generic lower bound for the present value costs of both option 1 and the risk cost of assets.

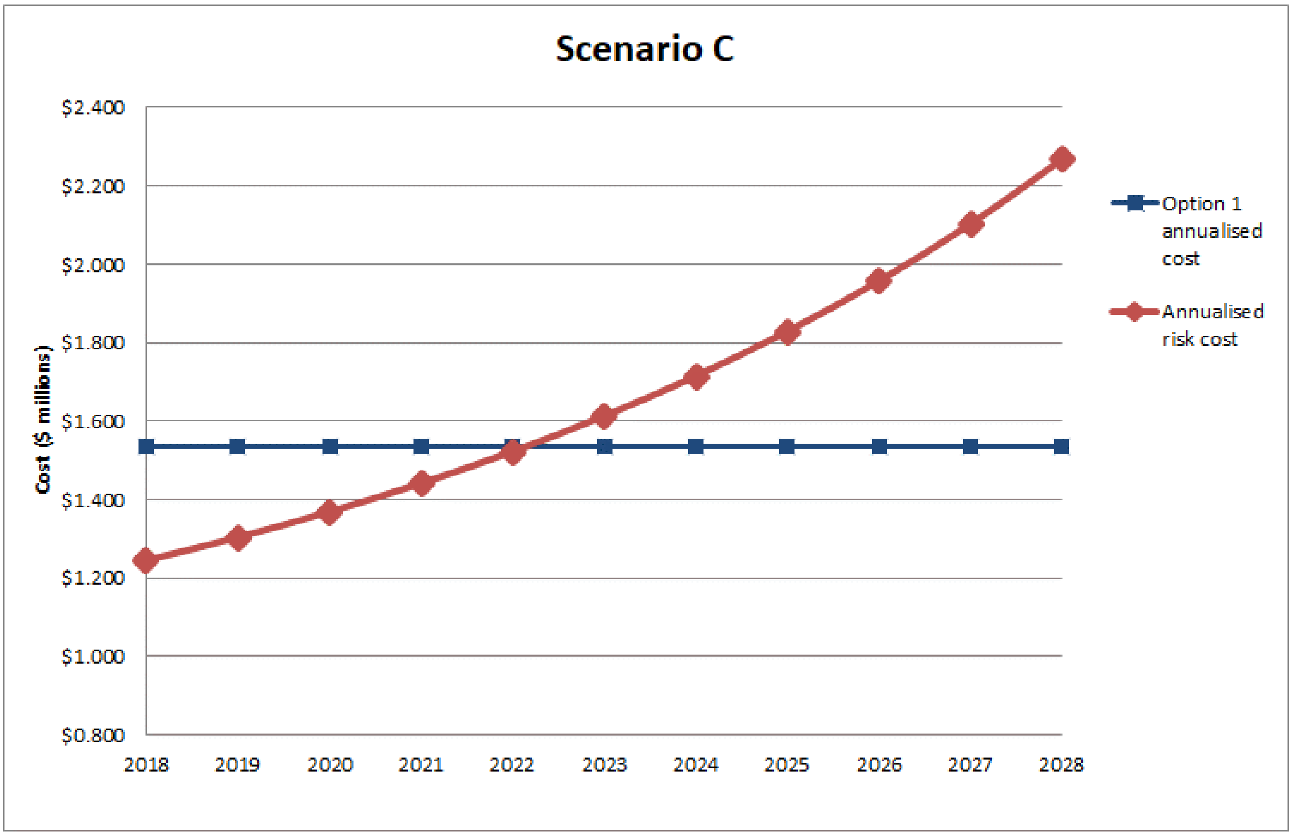
Figure 6.3 shows that under this scenario, the optimal time to commission option 1 is between 2019 and 2020.

The combination of assumptions adopted for scenario B (shown in table 6.3) is considered less likely to arise than the central forecasts that are applied in the central scenario.

6.5.4 Scenario C

Figure 6.4 below shows the annualised total cost of option 1 alongside the forecast annualised risk cost of assets under scenario C.

Figure 6.4 Results of economic assessment—scenario C



Scenario C defines a generic upper bound for the present value costs of both option 1 and the risk cost of assets.

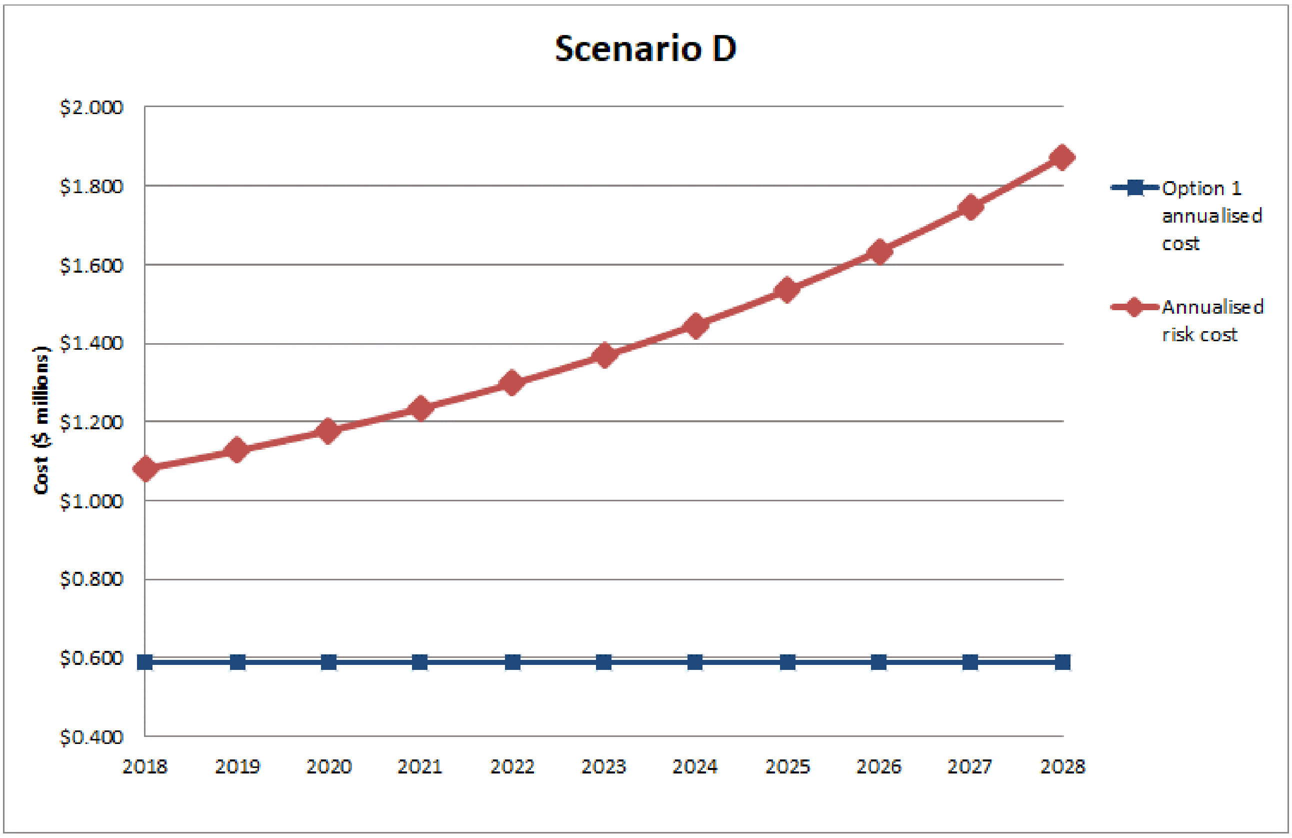
Figure 6.4 shows that under this scenario, the optimum time to commission option 1 is between 2022 and 2023.

The combination of assumptions adopted for scenario C (shown in table 6.3) is considered less likely to arise than the central forecasts that are applied in the central scenario.

6.5.5 Scenario D

The annual costs of option 1 and the risk cost of assets under scenario D are shown in figure 6.5 below.

Figure 6.5 Results of economic assessment—scenario D



Scenario D reflects a combination of assumptions that maximises the net market benefit of option 1 compared to the risk cost of assets.

Figure 6.5 indicates that under this scenario, it would be economic to commission option 1 as soon as practicable.

It is noted that the combination of assumptions adopted for scenario D (shown in table 6.3) is considered much less likely to arise than the central forecasts that are applied in the central scenario.

7 Checklist of regulatory compliance

6.5.6 Summary of results

Table 6.6 below provides a summary of results by listing the optimum timing of commissioning for option 1 under each scenario.

Table 6.6 Summary of results

Scenario	Description of scenario	Likelihood of scenario	Optimum timing
Central scenario	This scenario adopts the central estimate for each variable in the economic assessment.	Most likely	Between 2020 and 2021
Scenario A	A combination of variables that minimises the net market benefit of option 1 compared to the risk cost of assets.	Unlikely	After 2028
Scenario B	This scenario defines a generic lower bound for the present value costs of both option 1 and the risk cost of assets.	Less likely than central scenario	Between 2019 and 2020
Scenario C	This scenario defines a generic upper bound for the present value costs of both option 1 and the risk cost of assets.	Less likely than central scenario	Between 2022 and 2023
Scenario D	A combination of variables that maximises the net market benefit of option 1 compared to the risk costs of assets.	Unlikely	As soon as practicable

6.6 Selection of preferred option

Table 6.6 shows that under the most likely combination of assumptions and inputs, the optimum time to commission option 1 is between 2020 and 2021. In selecting the preferred option, we place most weight on this result, as we consider the central scenario to define the most likely state of the world.

Under scenarios B and C (which define generic, plausible lower and upper bounds for the costs of both option 1 and the risk cost of assets), the optimum time to commission option 1 is between 2019 and 2023. We place some weight on these results when selecting the preferred option, as we consider these two scenarios are less likely to arise than the central scenario.

In effect, scenarios A and D define the extreme lower and upper bounds of the net market benefit of option 1. Accordingly, they indicate a very wide range of optimal commissioning dates for option 1—namely, after 2028, and as soon as practicable. These two scenarios are considered to be the least likely to arise, so we place little weight on them when selecting the preferred option.

On the basis of the above analysis, we have identified 2021 as the optimum time to commission option 1, which is the most efficient option for addressing the identified need. We note that a commissioning date of 2021 is consistent with the signals provided by our CBRM analysis, which is outlined in section 3.2.

It is noted that the estimated total direct capital cost of option 1 is $17.04 million (in undiscounted 2018 dollars).

In order to meet the optimum commissioning date of 2021, detailed design is planned to commence in January 2019, and construction is planned to commence in January 2020.

6.7 Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D. This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

Table 7.1 lists the sections of this report that contain the information required by clause 5.17.4(j) of the Rules.

Table 7.1 Regulatory compliance checklist

Rules clause	Requirement	Section of this report
5.17.4(j)(1)	Description of the identified need for the investment	Section 3
5.17.4(j)(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 3
5.17.4(j)(3)	If applicable, a summary of, and commentary on, the submissions on the non-network options report	Section 4.2
5.17.4(j)(4)	Description of each credible option assessed	Section 4
5.17.4(j)(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	Sections 5 and 6
5.17.4(j)(6)	A quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	Sections 5 and 6.2
5.17.4(j)(7)	A detailed description of the methodologies used in quantifying each class of cost and market benefit	Sections 5 and 6
5.17.4(j)(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 6.4
5.17.4(j)(9)	The results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results	Section 6.5
5.17.4(j)(10)	The identification of the proposed preferred option	Sections 5 and 6.6
5.17.4(j)(11)	For the proposed preferred option, the RIT-D proponent must provide:	
	(i) details of the technical characteristics	Table 4.1
	(ii) the estimated construction timetable and commissioning date (where relevant)	Section 6.6
	(iii) the indicative capital and operating cost (where relevant)	Table 5.1
	(iv) a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution	Section 6.7
	(v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	CitiPower is the proponent