Revised Proposal

Attachment 5.14.1

Project Justification for 11kV Switchgear

January 2019

Content

1 OBJECTIVE

1.1 What is the purpose of this document

This document provides an updated summary of the need, options, timing and costs for the 11kV switchgear replacement projects that we have identified for the 2019-24 regulatory period.

This document builds on information provided by Ausgrid in Attachment 5.14.1 to our original proposal (Project justification for 11kV switchgear replacements). It updates a number of inputs, including demand forecasts and discount rates.

- It also addresses comments made by the AER and their consultants including:
  - Questions about mean time to repair (MTTR) input assumptions.
  - How the disproportionality factor was applied to the value of a statistical life saved.

We have provided further evidence to support the inclusion of these projects in our capex forecasts. This evidence includes the reasons why 11kV switchgear should be treated as a separate category in the repex model.

The attachment supports the need for the proposed 11kV switchgear projects, and shows that our analysis of timing, options and cost estimates are efficient and prudent as required by the National Electricity Rules (the Rules).

1.2 Where does this document fit with other material in our revised regulatory proposal

The underlying strategy and planning context for developing the 11kV switchgear replacement program has been described in Attachment 5.01 (Ausgrid's proposed capital expenditure). This information is critical to understanding how Ausgrid has developed its program within the context of its total forecast capex.

1.3 Structure and contents

The document provides a list of the major 11kV zone substation switchgear replacement projects forecast for the 2019-24 regulatory period.

We have firstly noted the projects that the AER has addressed in its Draft Decision via support of the related Demand Management Incentive Scheme (DMIS) proposals included in our substantive proposal.

For the remaining projects included in our revised proposal, we have provided additional and/or updated information in the Cost Benefit Analysis to support the need, options, timing and costs which establishes a valid case for the projects to proceed. For one project (Belrose) which was not previously identified, we have provided the information to support the need, options, timing and costs on a consistent basis to that supplied for the other projects.

For projects that have been deferred as a result of our review process, we have not provided further information and accept their deferral.

A key difference in this revised project justification is that we set out in more detail the particular issues associated with 11kV switchgear and their implications for safety and unserved energy. We have applied alternative input parameters to the modelling of the risk-cost of safety impacts of 11kV switchgear.

2 INTRODUCTION

2.1 An integral part of Ausgrid's distribution network

Switchgear is an essential part of Ausgrid's electrical network. When used in conjunction with protection systems, switchgear allows for the automatic protection of the power system to provide fast and efficient fault clearing. Switchgear is also used to provide switching capability and isolation points. Indoor switchgear consists of two major components, the switchboard and the circuit breaker. These components are recorded in the corporate asset management system as separate assets to ensure they are maintained and tested correctly.

2.2 Background

Ausgrid has progressively installed a number of different technology types for 11kV switchboards dating from the late 1930s. The first type of switchboard installed was compound insulated with bulk oil circuit breakers (OCB). As technology improved air insulated switchboards (non-internal arc classified technology) with bulk OCBs became widely available. In the next generation, these boards were superseded by air insulated switchboards with vacuum circuit breakers (VCB). The current technology being installed is Internal Arc Classified switchboards. This progression of technology, seen in Figure 1, has resulted in a corresponding reduction in risk of catastrophic failure. This reduction in risk was traded off against a larger construction footprint in a typical urban style Zone Substation.

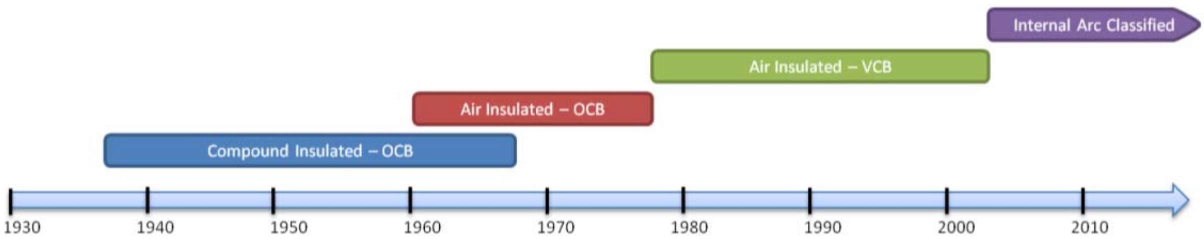


Figure 1. Installation history of 11kV switchboards

2.3 Compound insulated switchgear

Ausgrid installed compound insulated 11kV switchgear from the late 1930s until the early 1970s with examples from the 1930s still operating on the network today. This type of switchgear is characterised by bituminous compound in the busbar chamber. The bituminous compound electrically insulates the 11kV busbar during normal operation but is flammable and can act as a fuel source in the event of a fire.

There have been a significant number of failures of 11kV switchgear installed in Ausgrid zone substations with a range of consequences. Consequences can include simple equipment outages, expulsion of hot oil from the circuit breaker, small fires confined to the switchroom, to large fires that have burnt down an entire switchgear group and caused significant building damage. In the event of a fire, the presence of oil in the circuit breaker and flammable bituminous compound serves to exacerbate the consequences of the failure by acting as a fuel source for a fire.

Much of this type of equipment installed across the Ausgrid network is now approaching end of life, with continued service resulting in further deterioration in condition and an increasing number of failures.

The ability to support this switchgear technology into the future is becoming more costly. Ausgrid's inventory of spares for this equipment is limited and the expertise to perform required repairs is specialised. Repair for failures require bespoke engineering solutions specific to an individual switchboard installation. Repair is also heavily dependent on the nature and extent of damage to both the switchgear and the switchroom, with the realistic outcome in some cases that it cannot be repaired but only replaced.

2.4 Air insulated switchgear

From the 1960s Ausgrid began to install air insulated 11kV switchboards in preference to compound insulated switchboards. This type of switchboard still included bulk OCBs, however, was characterised by the lack of bituminous compound in the busbar chamber. It was progressively installed on the network until such time as air insulated switchgear with VCBs became widely available in the late 1970s.

The consequences of failure of this type of switchboard tends to be less severe than those of compound insulated switchboards due to the lack of insulating compound which would normally act as a fuel source. However, these faults are still severe enough to warrant a mitigating strategy. The possibility of staff in the vicinity during such a failure raises safety concerns due to the destructive failure mode produced by a fault within an OCB without arc fault containment. Additional 11kV network restrictions may be initiated from a fault within an air insulated switchboard. This is due to older air insulated switchboards having no internal arc containment and the possibility of conductive arc-products being transferred to other sections within the switchboard causing flashovers.

Due to their prevalence on the network, the degraded condition of the insulation and specialised design features of the 11kV air insulated switchgear and associated circuit breakers are a key issue for the ongoing management of the Ausgrid supply system.

2.5 Risk mitigation measures

As a result of the investigation of a number of switchgear failures, a range of measures have been undertaken to attempt to mitigate against the consequences of switchgear failure. One example is the vacuum circuit breaker replacement program.

Historically there have been a number of failures of bulk oil circuit breakers that have initiated, or had the potential to initiate, a fire within an indoor switchroom. The removal of oil filled circuit breakers and compound filled switchgear greatly reduces this risk. Modern vacuum technology circuit breakers are widely installed around the world and within Australia, replacing the highly combustible oil filled equivalents and removing the high potential fire risk.

A pre-existing program undertook the planned replacement of zone substation 11kV bulk oil circuit breakers installed in compound and air insulated switchboards to extend the life of the switchboard. This strategy is only viable where a vacuum conversion breaker can be cost effectively designed, manufactured and type tested. Switchboards with a unique or low population (orphan switchboards) of 11kV oil filled circuit breakers, such as English Electric CV OCBs, are not economical to replace with a modern vacuum circuit breaker, as sourcing of a modern day replacement requires research and development to meet the unique configuration of existing switchboards. Due to the lack of economies of scale, in such cases the preferred option is to replace the entire switchboard with a modern equivalent.

The strategies put in place mitigate, but do not eliminate the risk as key parts of the original switchboard remain in service. The only practical way to fully and cost effectively mitigate the risk is to retire and remove the aged and deteriorated switchboard with a modern equivalent.

2.6 Original proposal and assessment

Projects to replace 11kV switchgear were proposed as a specific category in our original submission. All of these projects result in retirement of the existing 11kV switchboard as well as all ancillary equipment. Replacement of 11kV switchboards is significantly more complex than like for like replacement of assets included in the repex model. Specific justification for the 11kV switchgear replacement portfolio was provided as Attachment 5.14.1 in our original Proposal for the 2019-24 regulatory period.

Overall, in the draft Determination AER "broadly commended Ausgrid's modelling approach" to assess 11kV switchgear replacement projects. However, the AER also expressed an opinion that a number of Ausgrid's input assumptions were conservative.

Specifically, for 11kV switchgear, the AER felt that "conservative mean time to repair input assumptions that are significantly longer than industry average" had been applied resulting in overstated unserved energy and quantified benefit calculations. The justification provided for 11kV switchboard projects in general was not accepted and any allowance for the category defaulted back to the repex model outcomes.

Given the variability between brownfield major switchboard projects, in terms of both pre-existing conditions and future needs, Ausgrid strongly believes that it is more appropriate to assess replacement of 11kV switchgear using cost benefit analysis rather than using the repex model alone.

Notwithstanding the above, in their draft determination the AER accepted Lidcombe, Mascot and St Ives 11kV switchgear replacement projects, to the extent that they included $8.5m in Ausgrid's base opex supported the business case for deferred investment facilitated by demand management

The cost benefit analysis material contained in this document supports the need for the proposed 11kV switchgear projects and shows that our analysis of timing, options and cost estimates are efficient and prudent as required by the National Electricity Rules (the Rules).

2.7 Cost Benefit Analysis Update

The following updates have been made to input parameters of cost benefit analysis for the 11kV switchgear projects where further justification is provided:

- Updated load forecast based on winter 2017 and summer 2017/18 actuals.
- Reduction of capex discount rate from 4.2% to 3.9% (pre-tax real) to be more consistent with the likely determination value for WACC.
- Reduction of the "grossly disproportionate factor" (as applied to the value of a statistical life saved) from 10 to 6.
- Adjustment of the indirect cost allocation for project cost to reflect variable component of indirect costs (treating indirect costs as 75% fixed and 25% variable consistent with recent AER decisions regarding corporate support cost allocations).

For the projects identified where funding was not supported in the draft AER determination, but where we believe should proceed, a revised cost benefit analysis has been undertaken using the parameters above. The findings are presented in the following Sections of this document.

To address the AER concerns regarding "conservative mean time to repair input assumptions that are significantly longer than industry average", sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission. In general this did not have a material impact on the timing of the projects. Its impact in individual cases is noted in the relevant CBA analysis below.

3 PORTFOLIO OF PROJECTS

3.1 Revised Portfolio

Table 1 provides an update for switchgear projects which were identified in our original submission in Attachment 5.14.1.

The revised project list for the 11kV switchgear replacement is divided in to five groups and is as below:

Group 1 - Projects from the current period which are committed / significantly progressed: Given these projects are partially completed, it is most prudent and efficient to complete them and deliver the underlying benefits.

Group 2 - Projects supported in draft determination via DM: The projects are those which "reflected a prudent and efficient capex opex trade-off".

Group 3 - Projects supported by updated assessment: The projects that are still required and have provided additional information to justify the project.

Group 4 – One new project supported by the updated assessment: A new project (Belrose) which was found to be favourable using the updated input parameters.

Group 5 - Projects deferred by revised assessment: Projects which have been deferred at this time due to use of the updated input parameters and for which Ausgrid is no longer seeking funding in the -24 regulatory control period.

Table 1 summarises the expected direct cost ($m real FY19) and timing of each project, as well as the AER draft determination findings and whether Ausgrid is providing further information in support of the updated project justification. Original project numbering from attachment 5.14.1 is retained.

Project name	Direct Cost ($m, real FY19) 2019-24	Direct Cost ($m, real FY19) Total	Revised CBA Date FY	Project completion Date	Start FY	End FY	AER Draft Determination acceptance	Further Justification provided
Projects continued as committed / inflight								
3. Enfield	15.1	24.3	-	Dec-2020	2017	2022	No	No
4. City East	14.0	33.5	-	Sep-2021	2017	2022	No	No
5. Dalley Street	15.3	25.9	-	Dec-2023	2017	2025	No	No
9. Surry Hills	4.4	13.1	-	Oct-2020	2018	2021	No	No
12. Flemington	3.2	5.2	-	Sep-2020	2018	2021	No	No
15. Darlinghurst (Stage 1)	0.4	2.1	-	Feb-2021	2018	2021	No	No
Subtotal	**52.4**	**104.1**						
Projects supported in draft determination								
1. Mascot (after DM)	11.8	32.5	-	Dec-2025	2022	2027	Yes	No
11. Lidcombe (Groups 1 & 2) (after DM)	1.4	17.2	-	Sep-2027	2024	2028	Yes	No
Subtotal	**13.2**	**49.7**						
Projects supported by revised assessment approach								
2. Concord	13.5	13.5	2018	Sep-2022	2019	2024	No	Yes
6. Clovelly	4.0	10.1	2024	Sep-2025	2022	2026	No	Yes
7. Miranda	9.4	9.5	2018	Sep-2022	2019	2023	No	Yes
8. Tarro	4.1	8.0	2024	Sep-2025	2022	2026	No	Yes
10. Botany	4.0	4.3	2023	Sep-2023	2021	2025	No	Yes
13. Stockton	3.8	4.2	2018	Mar-2021	2019	2022	No	Yes
17. Milperra	0.1	6.8	2024	Sep-2027	2024	2028	No	Yes
18. Pymble	3.2	8.9	2023	Dec-2025	2022	2027	No	Yes
19. Leightonfield	0.5	5.5	2022	Dec-2026	2023	2028	No	Yes
Subtotal	**42.6**	**70.8**						
New projects supported by revised assessment approach								
21. Belrose	6.0	6.0	2021	Sep-2022	2019	2023	-	Yes
Subtotal	**6.0**	**6.0**						
Projects deferred by revised assessment approach[1]								
14. Denman	*2.8*	*3.1*						No
15. Darlinghurst (Stage 2)	*0.0*	*12.4*						No
16. Riverwood	*1.3*	*8.0*						No
11. St Ives (after DM)	*0.0*	*11.8*					Yes	No
Subtotal	***4.1***	***35.3***						

Table 1. Revised project list for 11kV switchgear replacements

Notwithstanding the results of the revised CBA's and related benefits to the community, following extensive engagement with customer representatives and the AER, Ausgrid has taken the view that to help manage pricing impacts, we will accept and manage a higher level of risk, with the result that we have delayed commissioning dates for projects to a small degree compared to the CBA date. This reduces price pressures on customers now and

[1] Direct cost (Real FY19) based on original submission.

allows for a greater degree of optionality, should new alternatives emerge which could impact on the project

Only 11kV switchgear projects where we propose to provide further justification are discussed in this document.

4 PROJECT 2 – CONCORD

4.1 Project description

The driver for the project is the condition of the existing 11kV switchgear at the Concord 33/11kV Zone Substation, which is located in the Sydney Inner West Area of Ausgrid's network. The 11kV switchgear is compound insulated, 62 years of age, and is nearing the end of its life. The preferred network solution is that the switchgear is replaced with modern equivalent switchgear with control and protection equipment in a new switchroom building within the existing site. The direct project cost for such a solution is $13.5 million, which will be incurred almost entirely in the 2019-24 period.

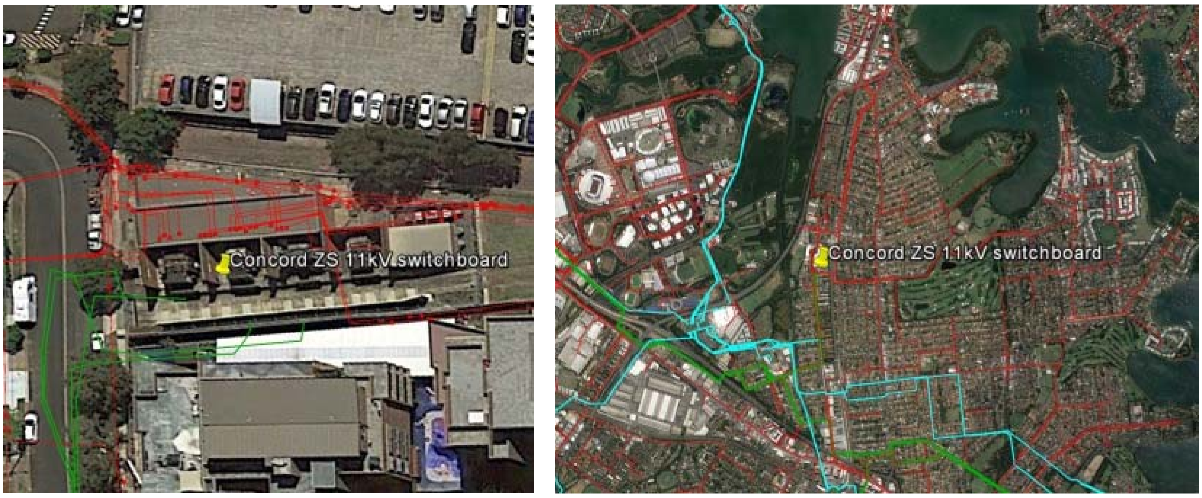


Figure 2. Concord Zone Substation

4.2 Additional and updated information

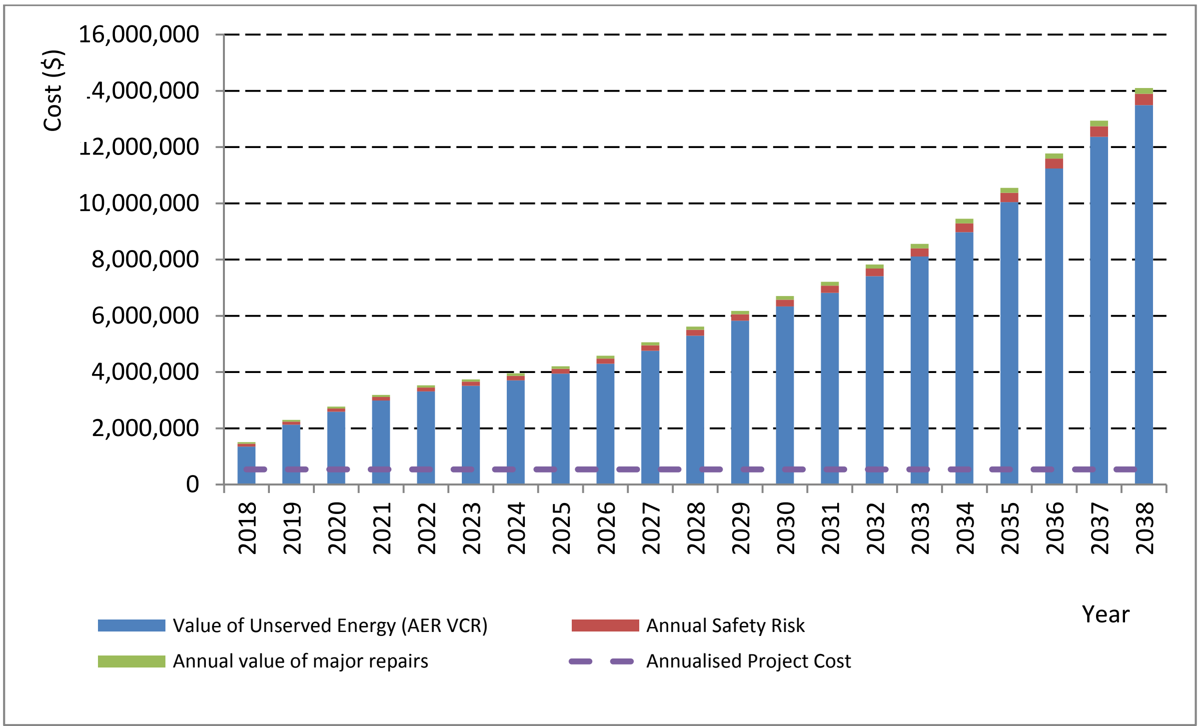
Based on the revised input parameters as detailed in section 3.1, the CBA was updated to determine the optimal timing of 11kV switchgear replacements. This includes the estimated benefit in terms of avoided unserved energy as a result of 11kV switchgear failure.

On the basis of network risk, the optimal timing for the replacement of 11kV switchgear at Concord is still 2018 (same as regulatory submission) and is illustrated in Figure 3 below.

A sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission and the influence to the timing was found not to be material. Hence, the optimal timing for the replacement of 11kV switchgear at Concord remains unchanged.

Based on deliverability and resource availability, while maintaining the required levels of reliability to customers, the delivery date for the proposed solution is 2022.

Figure 3. Updated risk cost versus project deferral benefit – Concord



4.3 Demand Management

An assessment of non-network options concluded that it is not considered probable that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable.

It is estimated that the cost of implementing a demand management solution would be at least 200% of the funds available for demand management, in order to achieve an equivalent NPV as the preferred supply-side investment. To arrive at this conclusion, a detailed demand management cost-benefit assessment was carried out which considered the project cost, an assumed option value of 5% per year of deferral, demand management unserved energy benefits and terminal value over a 20 year time horizon.

Closer to the need date a more detailed assessment will be conducted as part of the Regulatory Investment Test.

4.4 Costing

The proposed direct cost cash flow for the project is outlined in the table below.

Table 2. Project direct cost cash flow ($m, real FY19)

	Previous years	2019-20	2020-21	2021-22	2022-23	2023-24	Later years
Network Option	0.1	0.5	1.5	9.8	1.6	0.0	-

5 PROJECT 6 – CLOVELLY

5.1 Project description

The project is to retire and replace the existing air insulated 11kV switchgear (Group 2) at Clovelly Zone Substation in the Eastern Suburbs region of Ausgrid's network. Clovelly Zone Substation comprises both air and compound insulated 11kV switchgear which are aged around 47 years. Its poor condition has resulted in its prioritisation for retirement. As a result of this prioritisation in 2012, the compound-insulated 11kV switchgear at Clovelly Zone Substation (Group 1) was given the highest priority for retirement. A project is in progress to transfer the Group 1 load to adjacent zone substations (Kingsford and Waverley Zone Substations), then to decommission and retire Group 1 switchgear and the associated transformers. This stage is scheduled for completion in 2019. The air insulated 11kV switchgear is also nearing the end of its life and is forecast to exhibit increased rates of failure as it continues to age. The direct project cost of the proposed solution is $10.1 million, of which $4.0 million is forecast to be incurred in the 2019-24 period.

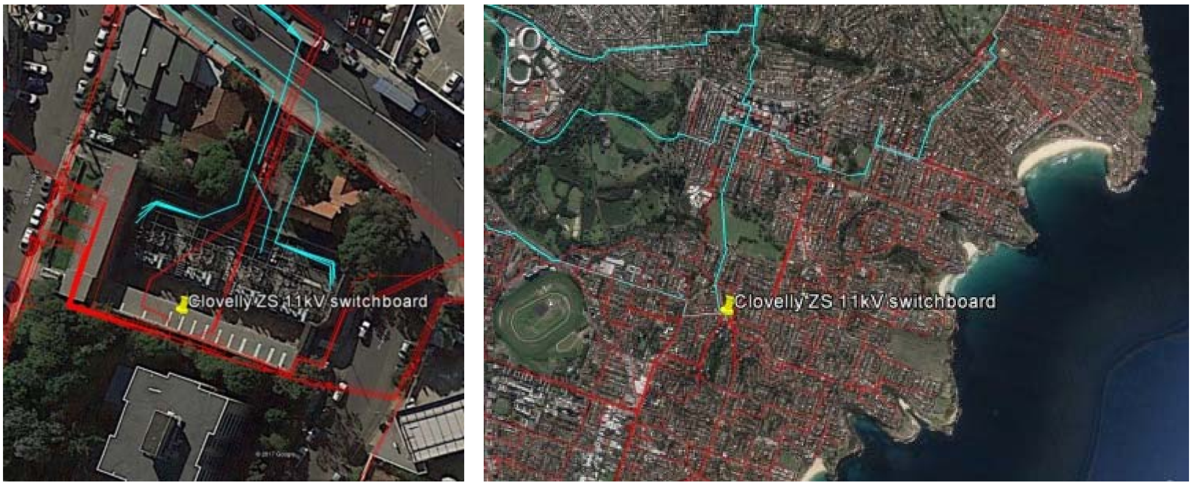


Figure 4. Clovelly Zone Substation

5.2 Additional and updated information

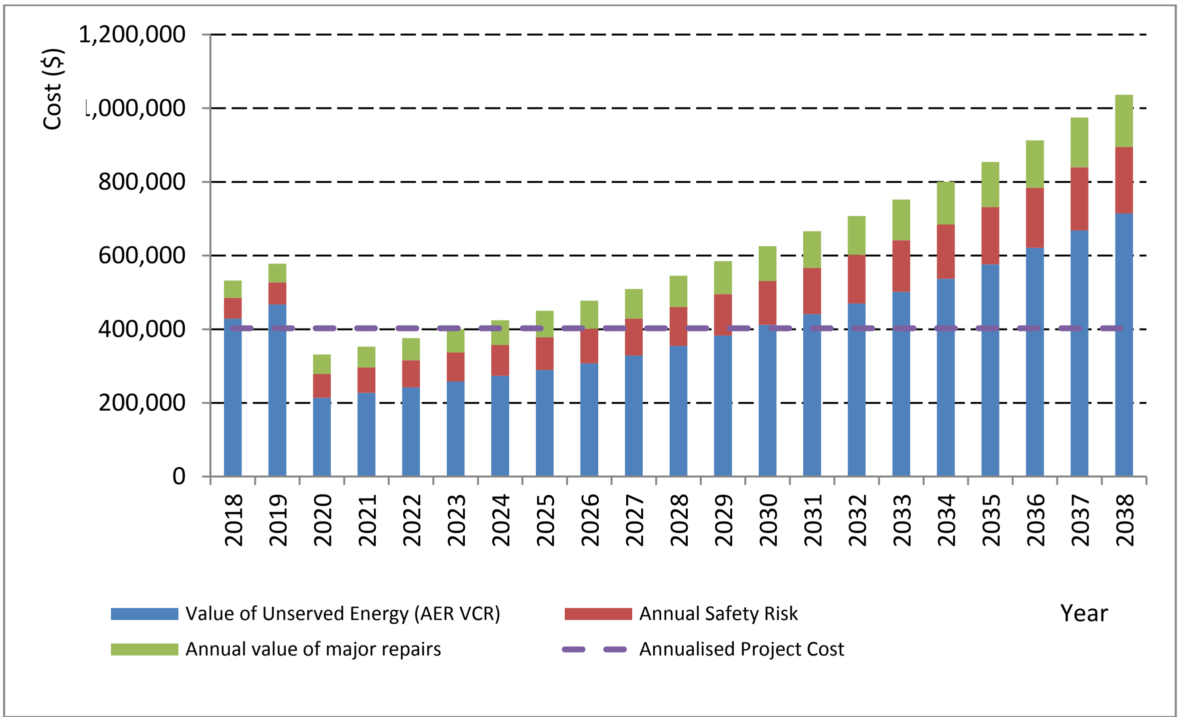
Based on the revised input parameters as detailed in section 3.1, the CBA was updated to determine the optimal timing of 11kV switchgear replacements. This includes the estimated benefit in terms of avoided unserved energy as a result of 11kV switchgear failure.

On the basis of network risk, the optimal timing for the replacement of 11kV switchgear at Clovelly is 2024 and is illustrated in Figure 5 below.

A sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission and the influence to the timing was found not to be material. Hence, the optimal timing for the replacement of 11kV switchgear at Clovelly remains unchanged.

Based on deliverability and resource availability, while maintaining the required levels of reliability to customers, the delivery date for the proposed solution is 2025.

Figure 5. Updated risk cost versus project deferral benefit - Clovelly



Note: The network risk is reduced from 2019 to 2020 due to a committed project to decommission 11kV switchgear Group 1 at Clovelly zone.

5.3 Demand Management

An assessment of non-network options concluded that it is not considered probable that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable.

It is estimated that the cost of implementing a demand management solution would be at least 400% of the funds available for demand management, in order to achieve an equivalent NPV as the preferred supply-side investment. To arrive at this conclusion, a detailed demand management cost-benefit assessment was carried out which considered the project cost, an assumed option value of 5% per year of deferral, demand management unserved energy benefits and terminal value over a 20 year time horizon.

Closer to the need date a more detailed assessment will be conducted as part of the Regulatory Investment Test.

5.4 Costing

The proposed direct cost cash flow for the project is outlined in the table below.

Table 3. Project direct cost cash flow ($m, real FY19)

	Previous years	2019-20	2020-21	2021-22	2022-23	2023-24	Later years
Network Option	-	-	-	0.3	0.6	3.1	6.1

6 PROJECT 7 – MIRANDA

6.1 Project description

The project is to replace the existing 11kV switchgear at Miranda Zone Substation in the Sutherland region of Ausgrid's network. The compound insulated switchgear is nearing the end of its life. Based on the cost-benefit analysis and other considerations, the switchboard should be replaced by 2022. The option analysis suggests that the asset should be replaced with modern equivalent switchgear. The direct project cost of the proposed solution is $9.5 million, of which $9.4 million is forecast to be incurred in the 2019-24 period.

Figure 6. Miranda Zone Substation

6.2 Additional and updated information

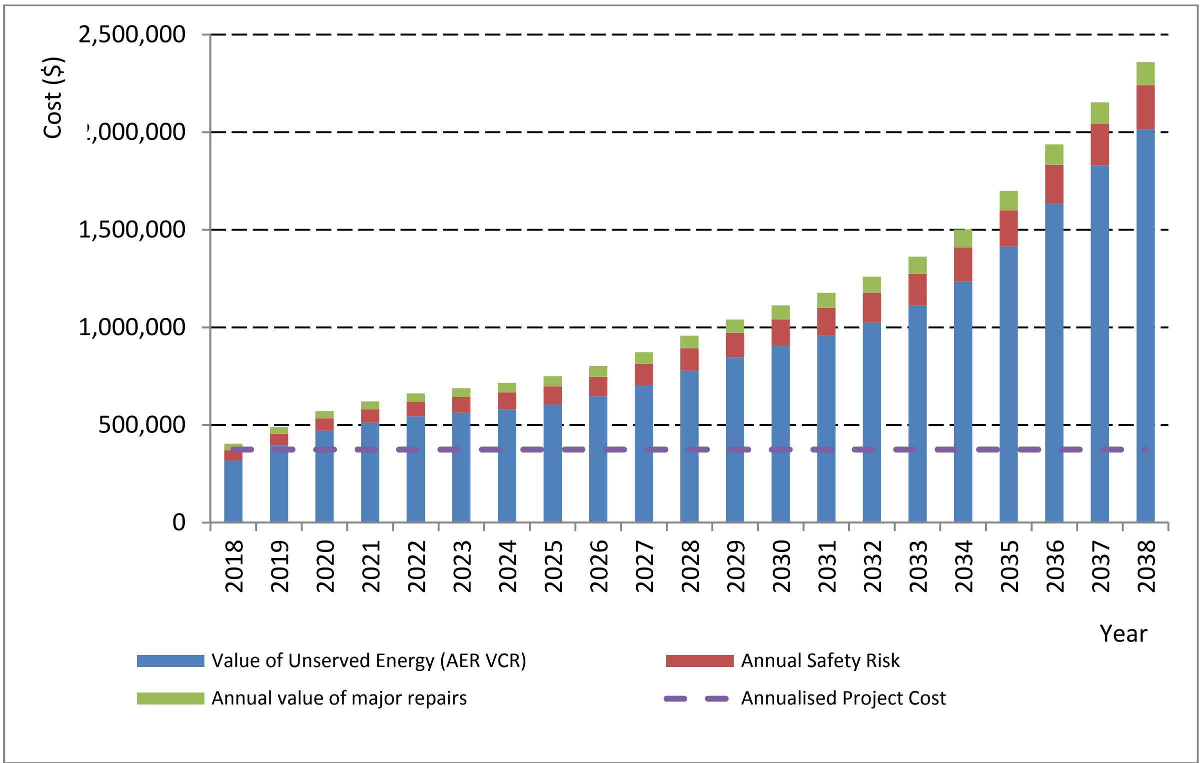
Based on the revised input parameters as detailed in section 3.1, the CBA was updated to determine the optimal timing of 11kV switchgear replacements. This includes the estimated benefit in terms of avoided unserved energy as a result of 11kV switchgear failure.

On the basis of network risk, the optimal timing for the replacement of 11kV switchgear at Miranda is 2018 and is illustrated in Figure 7 below.

A sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission and the influence to the timing was found not to be material. Hence, the optimal timing for the replacement of 11kV switchgear at Miranda remains unchanged.

Based on deliverability and resource availability, while maintaining the required levels of reliability to customers, the delivery date for the proposed solution is 2022.

Figure 7. Updated risk cost versus project deferral benefit - Miranda



6.3 Demand Management

An assessment of non-network options concluded that it is not considered probable that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable.

It is estimated that the cost of implementing a demand management solution would be at least 500% of the funds available for demand management, in order to achieve an equivalent NPV as the preferred supply-side investment. To arrive at this conclusion, a detailed demand management cost-benefit assessment was carried out which considered the project cost, an assumed option value of 5% per year of deferral, demand management unserved energy benefits and terminal value over a 20 year time horizon.

Closer to the need date a more detailed assessment will be conducted as part of the Regulatory Investment Test.

6.4 Costing

The proposed direct cost cash flow for the project is outlined in the table below.

Table 4. Project direct cost cash flow ($m, real FY19)

	Previous years	2019-20	2020-21	2021-22	2022-23	2023-24	Later years
Network Option	0.1	0.9	4.8	3.1	0.6	-	-

7 PROJECT 8 – TARRO

7.1 Project description

The project is to retire the existing 11kV switchgear at Tarro Zone Substation in the Maitland region of Ausgrid's network. The compound insulated switchboard is nearing the end of its life. Based on cost-benefit analysis these assets should be retired by the end of 2025. Our option analysis suggests that the asset should be replaced with modern equivalent switchgear. The total project direct cost is $8.0 million, of which $4.1 million is forecast to be incurred in the 2019-24 period.

Figure 8. Tarro Zone Substation

7.2 Additional and updated information

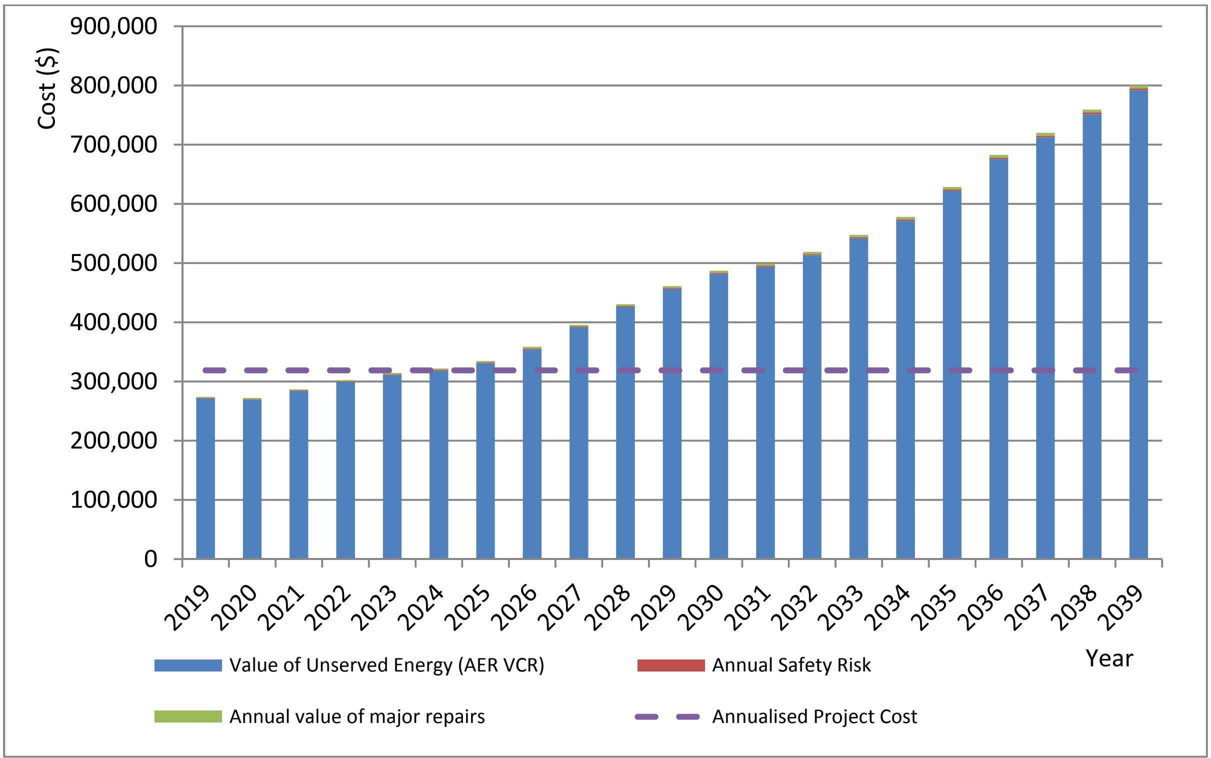
Based on the revised input parameters as detailed in section 3.1, the CBA was updated to determine the optimal timing of 11kV switchgear replacements. This includes the estimated benefit in terms of avoided unserved energy as a result of 11kV switchgear failure.

On the basis of network risk, the optimal timing for the replacement of 11kV switchgear at Tarro is 2024 and is illustrated in Figure 9 below.

A sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission. Under that scenario the timing for the replacement of 11kV switchgear at Tarro zone substation would be somewhat delayed. It is noted, however, that adoption of this shorter MTTR as the basis to delay the project would leave Tarro customers exposed to outages of more than a week on failure of a switchboard, given the limited load transfer capability to other substations. This is in contrast to more urban scenarios where we are able to transfer load away to adjacent zone substations more quickly and a significantly smaller proportion of customers are directly exposed to the MTTR.

Based on deliverability and resource availability, while maintaining the required levels of reliability to customers, the delivery date for the preferred network solution is 2025.

Figure 9. Updated risk cost versus project deferral benefit – Tarro



7.3 Demand Management

Past assessments of non-network options have concluded that it is not considered probable that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable.

Closer to the project initiation date a more detailed assessment will be conducted as part of the Regulatory Investment Test.

7.4 Costing

The proposed direct cost cash flow for the project is outlined in the table below.

Table 5. Project direct cost cash flow ($m, real FY19)

	Previous years	2019-20	2020-21	2021-22	2022-23	2023-24	Later years
Network Option	-	-	-	0.3	0.7	3.1	3.9

8 PROJECT 10 – BOTANY

8.1 Project description

The project is to replace the existing 11kV switchgear (Group 1) at Botany Zone Substation in the Eastern Suburbs region of Ausgrid's network. The compound-insulated switchgear is nearing the end of its life, and the cost-benefit analysis and other considerations supports the retirement of these assets by the end of 2023. Our options analysis suggests that the asset should be replaced with modern equivalent switchgear on the existing site. The direct project cost of the proposed solution is $4.3 million, of which $4.0 million is forecast to be incurred in the 2019-24 period.

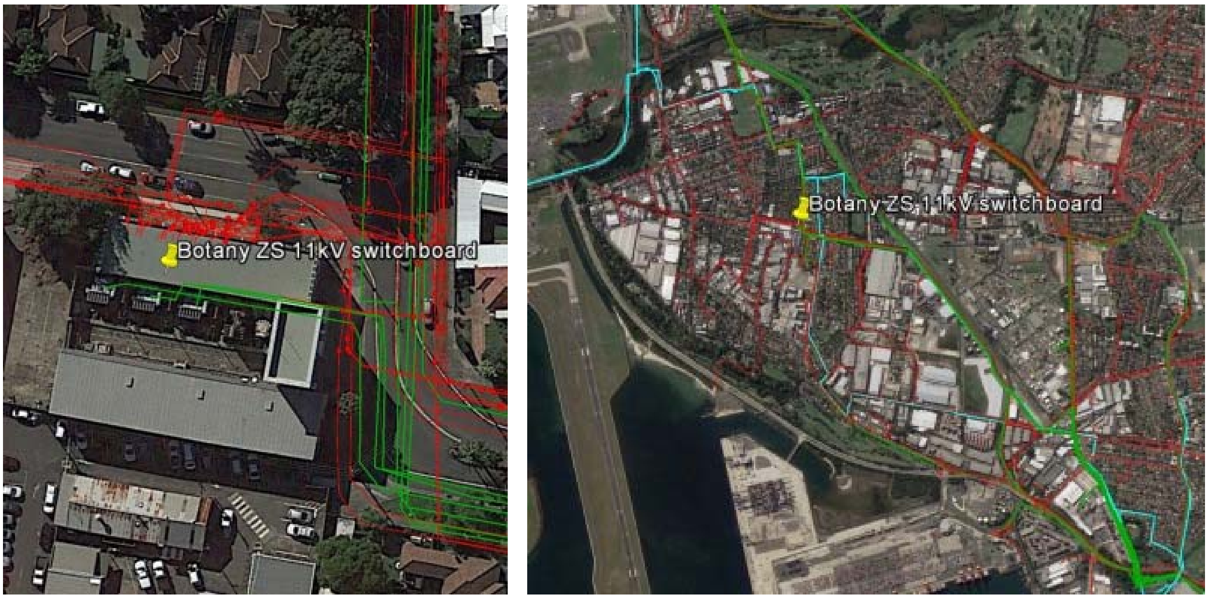


Figure 10. Botany Zone Substation

8.2 Additional and updated information

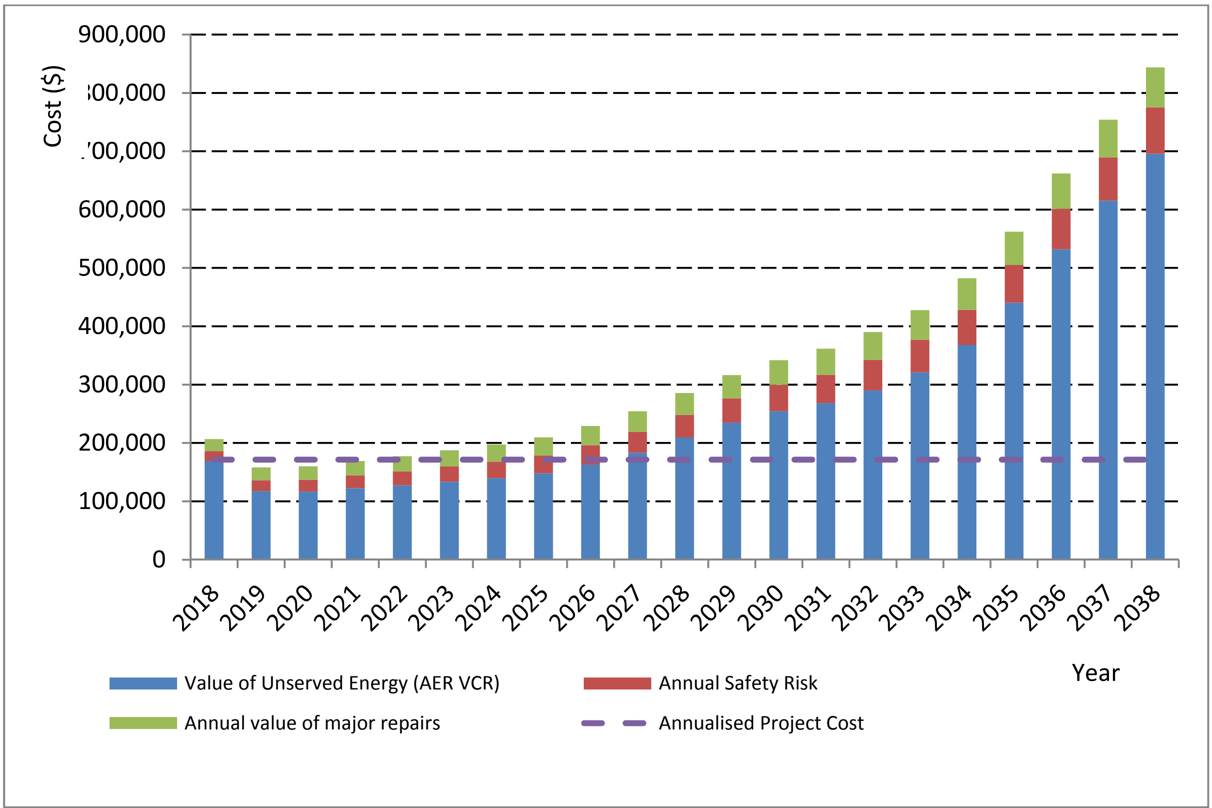
Based on the revised input parameters as detailed in section 3.1, the CBA was updated to determine the optimal timing of 11kV switchgear replacements. This includes the estimated benefit in terms of avoided unserved energy as a result of 11kV switchgear failure.

On the basis of network risk, the optimal timing for the replacement of 11kV switchgear at Botany is 2023 and is illustrated in Figure 11 below.

A sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission and the influence to the timing was found not to be material. Hence, the optimal timing for the replacement of 11kV switchgear at Botany remains unchanged.

Based on deliverability and resource availability, while maintaining the required levels of reliability to customers, the delivery date for the preferred network solution is 2023.

Figure 11. Updated risk cost versus project deferral benefit - Botany



8.3 Demand Management

An assessment of non-network options concluded that it is not considered probable that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable.

It is estimated that the cost of implementing a demand management solution would be at least 300% of the funds available for demand management, in order to achieve an equivalent NPV as the preferred supply-side investment. To arrive at this conclusion, a detailed demand management cost-benefit assessment was carried out which considered the project cost, an assumed option value of 5% per year of deferral, demand management unserved energy benefits and terminal value over a 20 year time horizon.

Closer to the need date a more detailed assessment will be conducted as part of the Regulatory Investment Test.

8.4 Costing

The proposed direct cash flow for the project is outlined in the table below.

Table 6. Project direct cost cash flow ($m, real FY19)

	Previous years	2019-20	2020-21	2021-22	2022-23	2023-24	Later years
Network Option	-	-	-	0.3	1.3	2.4	0.3

9 PROJECT 13 – STOCKTON

9.1 Project description

The project is to replace the existing 11kV switchgear at Stockton in the Newcastle region of Ausgrid's network. The compound insulated switchgear is nearing the end of its life, and based on the cost-benefit analysis and other considerations the switchgear should be replaced by 2021. Our options analysis suggests that the asset should be replaced with modern equivalent switchgear, requiring construction of a new switch room with control and protection changes. The direct project cost of the proposed solution is $4.2 million, of which $3.8 million is forecast to be incurred in the 2019-24 period.

Figure 12. Stockton Zone Substation

9.2 Additional and updated information

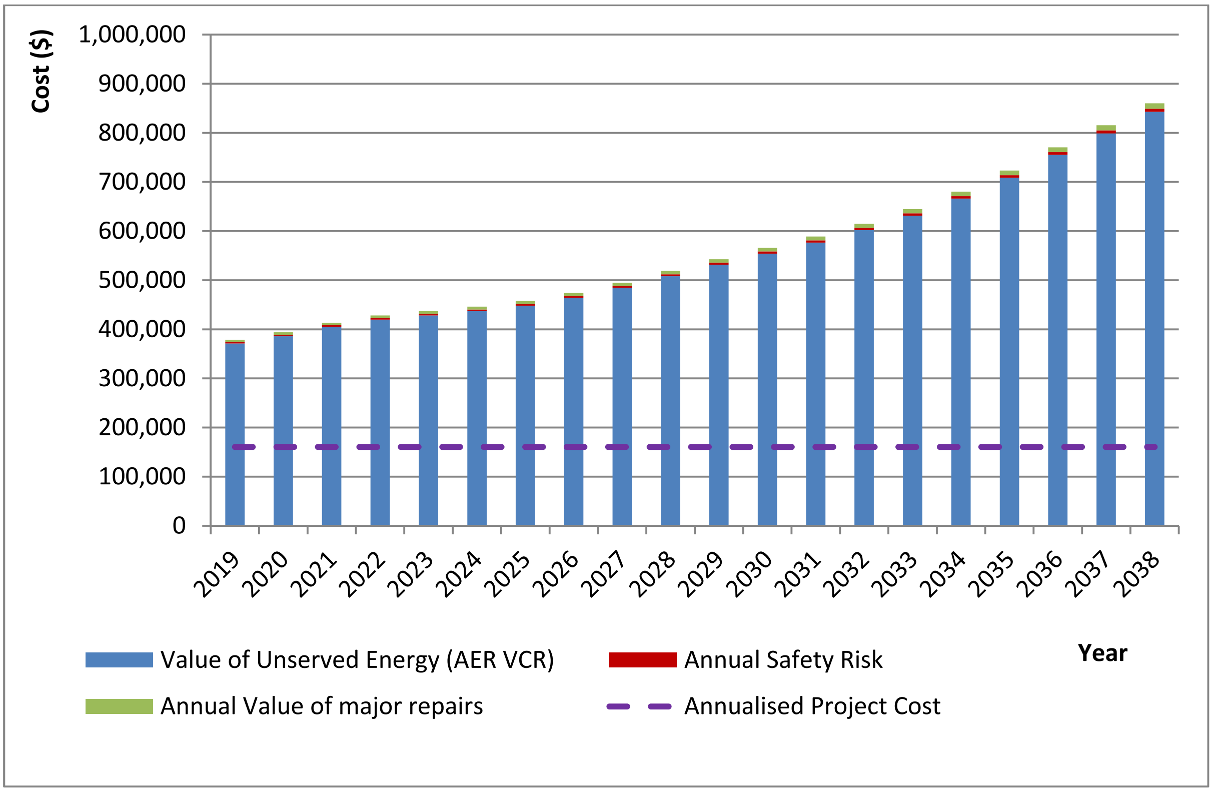
Based on the revised input parameters as detailed in section 3.1, the CBA was updated to determine the optimal timing of 11kV switchgear replacements. This includes the estimated benefit in terms of avoided unserved energy as a result of 11kV switchgear failure.

On the basis of network risk, the optimal timing for the replacement of 11kV switchgear at Stockton is still 2018 (same as regulatory submission) and is illustrated in Figure 13 below.

A sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission and the influence to the timing was found not to be material. Hence, the optimal timing for the replacement of 11kV switchgear at Stockton remains unchanged.

Based on deliverability and resource availability, while maintaining the required levels of reliability to customers, the delivery date for the preferred network solution is 2021.

Figure13. Updated risk cost versus project deferral benefit - Stockton



9.3 Demand Management

An assessment of non-network options concluded that it is not considered probable that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable.

It is estimated that the cost of implementing a demand management solution would be at least 500% of the funds available for demand management, in order to achieve an equivalent NPV as the preferred supply-side investment. To arrive at this conclusion, a detailed demand management cost-benefit assessment was carried out which considered the project cost, an assumed option value of 5% per year of deferral, demand management unserved energy benefits and terminal value over a 20 year time horizon.

Closer to the need date a more detailed assessment will be conducted as part of the Regulatory Investment Test.

9.4 Costing

The proposed direct cost cash flow for the project is outlined in the table below.

Table 7. Project direct cost cash flow ($m, real FY19)

	Previous years	2019-20	2020-21	2021-22	2022-23	2023-24	Later years
Network Option	0.4	3.2	0.5	0.1	-	-	-

10 PROJECT 17 – MILPERRA

10.1 Project description

The project is to replace the existing compound insulated 11kV switchgear (Group 1) at Milperra zone, which is supplied from the TransGrid owned Sydney South BSP. Milperra is in the Canterbury Bankstown region of Ausgrid's network and comprises both compound insulated and air insulated switchboard. The compound insulated switchgear is nearing the end of its life. Based on the cost-benefit analysis and other considerations the switchgear should be replaced by 2027. The project involves replacement of compound insulated 11kV switchgear in a new switchroom on the existing Milperra zone site. The direct project cost of the proposed solution is $6.8 million, of which $0.1 million is forecast to be incurred in the 2019-24 period.

Figure 14. Milperra Zone Substation

10.2 Additional and updated information

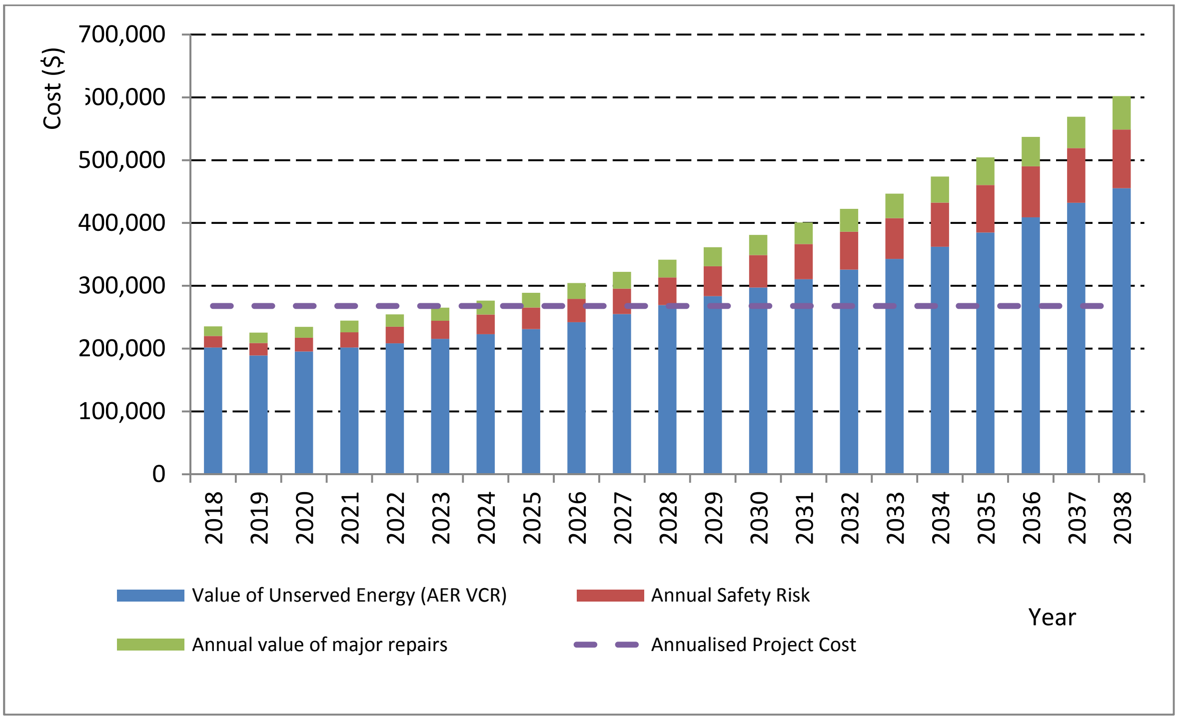
Based on the revised input parameters as detailed in section 3.1, the CBA was updated to determine the optimal timing of 11kV switchgear replacements. This includes the estimated benefit in terms of avoided unserved energy as a result of 11kV switchgear failure.

On the basis of network risk, the optimal timing for the replacement of 11kV switchgear at Milperra is 2024 and is illustrated in Figure 15 below.

A sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission and the influence to the timing was found not to be material. Hence, the optimal timing for the replacement of 11kV switchgear at Milperra remains unchanged.

Based on deliverability and resource availability, while maintaining the required levels of reliability to customers, the delivery date for the preferred network solution is 2027.

Figure 15. Updated risk cost versus project deferral benefit - Milperra



10.3 Demand Management

An assessment of non-network options concluded that it is not considered probable that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable.

It is estimated that the cost of implementing a demand management solution would be at least 400% of the funds available for demand management, in order to achieve an equivalent NPV as the preferred supply-side investment. To arrive at this conclusion, a detailed demand management cost-benefit assessment was carried out which considered the project cost, an assumed option value of 5% per year of deferral, demand management unserved energy benefits and terminal value over a 20 year time horizon.

Closer to the need date a more detailed assessment will be conducted as part of the Regulatory Investment Test.

10.4 Costing

The proposed direct cost cash flow for the project is outlined in the table below.

Table 8. Project direct cost cash flow ($m, real FY19)

	Previous years	2019-20	2020-21	2021-22	2022-23	2023-24	Later years
Network Option	-	-	-	-	-	0.1	6.7

11 PROJECT 18 – PYMBLE

11.1 Project description

The project is to replace the existing 11kV switchgear at Pymble 33/11kV Zone Substation in the Upper North Shore region of Ausgrid's network. The substation comprises both compound insulated and air-insulated switchgear that are both nearing their end of life. Based on the cost-benefit analysis and other considerations, the asset should be replaced by 2025. The options analysis suggests that the asset should be replaced with modern equivalent switchgear. There is limited available space on the site, and the work will require the installation of temporary equipment to allow the progressive replacement of the switchgear. The direct project cost of the proposed solution is $8.9 million, of which $3.2 million is forecast to be incurred in the 2019-24 period.

Figure 16. Pymble Zone Substation

11.2 Additional information to justify project

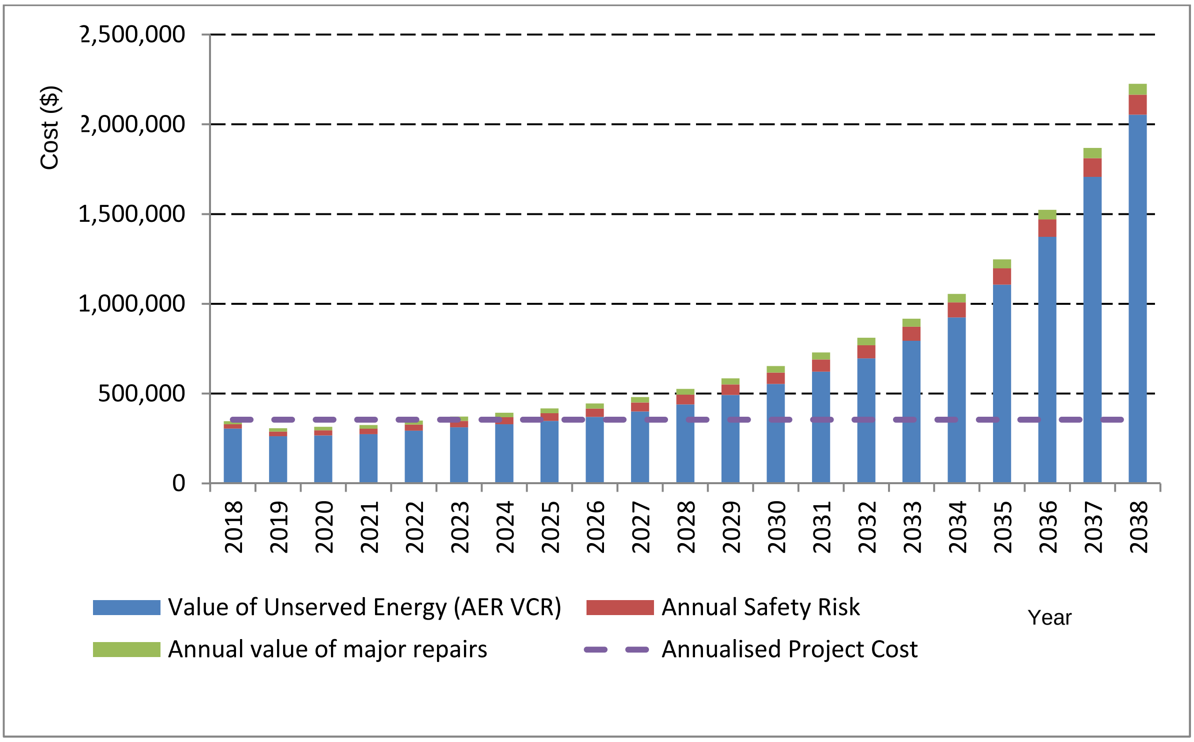
Based on the revised input parameters as detailed in section 3.1, the CBA was updated to determine the optimal timing of 11kV switchgear replacements. This includes the estimated benefit in terms of avoided unserved energy as a result of 11kV switchgear failure.

On the basis of network risk, the optimal timing for the replacement of 11kV switchgear at Pymble is 2023 and is illustrated in Figure 17 below.

A sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission and the influence to the timing was found not to be relatively material. Hence, the optimal timing for the replacement of 11kV switchgear at Pymble remains unchanged.

Based on deliverability and resource availability, while maintaining the required levels of reliability to customers, the delivery date for the preferred network solution is 2025.

Figure 17. Updated risk cost versus project deferral benefit – Pymble



11.3 Demand Management

An assessment of non-network options concluded that it is not considered probable that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable.

It is estimated that the cost of implementing a demand management solution would be at least 400% of the funds available for demand management, in order to achieve an equivalent NPV as the preferred supply-side investment. To arrive at this conclusion, a detailed demand management cost-benefit assessment was carried out which considered the project cost, an assumed option value of 5% per year of deferral, demand management unserved energy benefits and terminal value over a 20 year time horizon.

Closer to the need date a more detailed assessment will be conducted as part of the Regulatory Investment Test.

11.4 Costing

The proposed direct cost cash flow for the project is outlined in the table below.

Table 9. Project direct cost cash flow ($m, real FY19)

	Previous years	2019-20	2020-21	2021-22	2022-23	2023-24	Later years
Network Option	-	-	-	0.0	0.7	2.5	5.7

12 PROJECT 19 – LEIGHTONFIELD

12.1 Project description

The project is to replace the existing 11kV switchgear at Leightonfield, which is a 33kV Zone Substation, supplied via Endeavour Energy's network from its Guildford Subtransmission Substation. Leightonfield is in the Canterbury Bankstown region of Ausgrid's network. The compound insulated switchgear is nearing the end of its life, and some of the 33kV equipment does not comply with Ausgrid's safety standards. The work is to take place in two stages, the first stage addresses medium term issues with three 11kV switchgear panels. It was committed for completion during FY 2019. The second stage involves replacement of remaining 11kV switchgear. Based on the cost-benefit analysis and other considerations, the asset should be replaced by 2026. The direct cost of the proposed solution is $5.5 million, of which $0.5 million is forecast to be incurred in the 2019-24 period.

Figure 18. Leightonfield Zone Substation

12.2 Additional and updated information

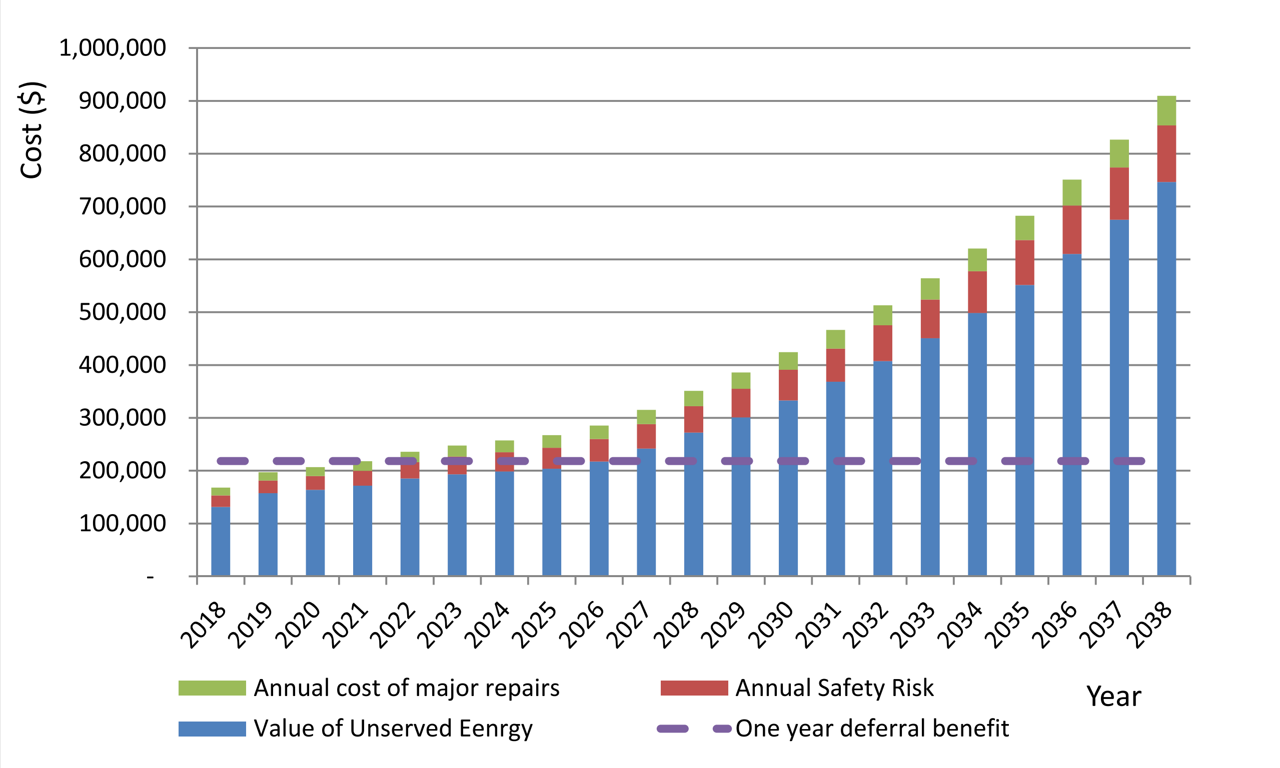
Based on the revised input parameters as detailed in section 3.1, the CBA was updated to determine the optimal timing of 11kV switchgear replacements. This includes the estimated benefit in terms of avoided unserved energy as a result of 11kV switchgear failure.

On the basis of network risk, the optimal timing for the replacement of 11kV switchgear at Leightonfield is 2022 and is illustrated in Figure 19 below.

A sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission and the influence to the timing was found not to be material. Hence, the optimal timing for the replacement of 11kV switchgear at Leightonfield remains unchanged.

Based on deliverability and resource availability, while maintaining the required levels of reliability to customers, the delivery date for the preferred network solution is 2026.

Figure 19. Updated risk cost versus project deferral benefit - Leightonfield



12.3 Demand Management

An assessment of non-network options concluded that it is not considered probable that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable.

It is estimated that the cost of implementing a demand management solution would be at least 200% of the funds available for demand management, in order to achieve an equivalent NPV as the preferred supply-side investment. To arrive at this conclusion, a detailed demand management cost-benefit assessment was carried out which considered the project cost, an assumed option value of 5% per year of deferral, demand management unserved energy benefits and terminal value over a 20 year time horizon.

Closer to the need date a more detailed assessment will be conducted as part of the Regulatory Investment Test.

12.4 Costing

The proposed direct cost cash flow for the project is outlined in the table below.

Table 10. Project direct cash flow ($m, real FY19)

	Previous years	2019-20	2020-21	2021-22	2022-23	2023-24	Later years
Network Option	-	-	-	-	0.0	0.5	5.0

13 PROJECT 21 – BELROSE

13.1 Project description

The project is to replace the existing 11kV switchboard in the Belrose 33/11kV Zone Substation in the Warringah Area of Ausgrid's network. The air-insulated switchboard is nearing the end of its life. Based on the cost-benefit analysis and other considerations, the asset should be replaced by 2022. The preferred network solution is that the switchboard is replaced with modern equivalent switchgear in the existing building. The total project direct cost for such a solution is $6.0 million, which will be incurred almost entirely in the 2019-24 period.

Figure 20. Belrose Zone Substation

13.2 Need

Belrose is a 33/11kV Zone Substation commissioned in 1963, and is supplied from Warringah STS. The zone was commissioned in 1963, including the 11kV switchboard.

Belrose Zone Substation comprises three sections of single bus air insulated 11kV switchboard with vacuum circuit breakers. The 11kV air switchboard is Email type LC and was recommended for replacement in 2025 in Ausgrid's switchboard replacement program, based on a condition assessment that identified reliability and safety risks. While the switchboard is not exposed to the same failure modes as the earlier bulk oil and compound technology, it faces an increasing risk or failure and poor spares availability with the potential to create difficulties in responding to faults/failures. It also has limited segregation between busbar chambers leading to the risk of migration of arcing products during a bus fault, leading to more severe consequences than with modern air insulated equipment.

The main considerations driving the replacement of the 11kV switchboard at Belrose zone are the expected contribution to unserved energy and safety risks.

13.3 Options

We examined the following options as part of Ausgrid's planning process:

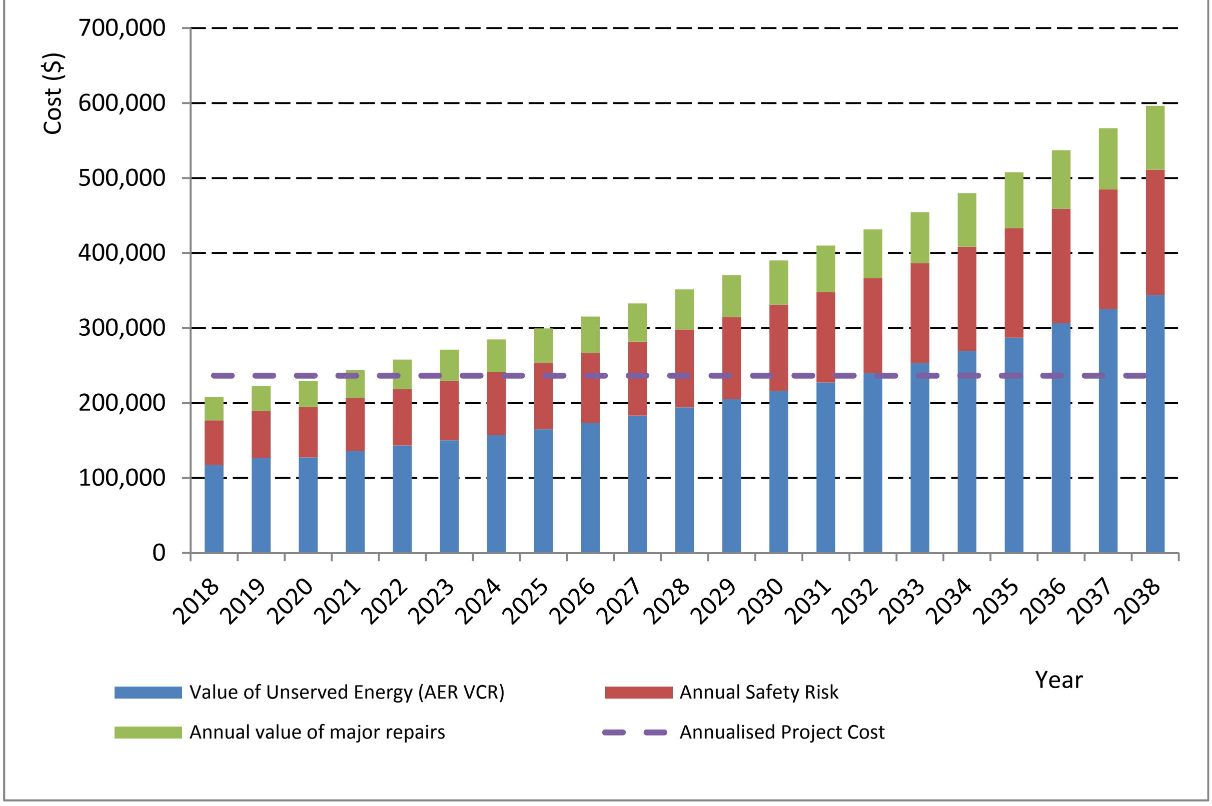
1. Replace Belrose 11kV switchboard with modern equivalent switchboard in the existing building.
2. Retire Belrose zone by transferring load to the surrounding zone substations.
3. Retire Belrose zone substation by constructing a new zone substation nearby and transferring all load to the new zone substation.
4. Consideration of demand management.

The preferred and most cost effective network solution to resolve issues at Belrose Zone Substation is Option 1, namely to replace the 11kV switchgear with modern equivalent switchgear in the existing building.

13.4 Timing

Cost benefit analysis, including consideration of unserved energy, repair costs, and safety risks, identified 2021 as the point where the benefits of the project exceeded the annualised costs. This is illustrated in the cost and benefit graph below.

Figure 21. Risk cost versus project deferral benefit - Belrose



A sensitivity analysis was done using 50% of mean time to repair (MTTR) compared to our original submission and the influence to the timing was found not to be material. Hence, the optimal timing for the replacement of 11kV switchboard at Belrose remains unchanged.

Based on deliverability and resource availability, while maintaining the required levels of reliability to customers, the delivery date for the preferred network solution is 2022.

13.5 Demand Management

An assessment of non-network options concluded that it is not considered probable that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make the project deferral technically and economically viable.

It is estimated that the cost of implementing a demand management solution would be at least 300% of the funds available for demand management, in order to achieve an equivalent NPV as the preferred supply-side investment. To arrive at this conclusion, a detailed demand management cost-benefit assessment was carried out which considered the project cost, an assumed option value of 5% per year of deferral, demand management unserved energy benefits and terminal value over a 20 year time horizon.

Closer to the need date a more detailed assessment will be conducted as part of the Regulatory Investment Test.

13.6 Costing

We undertook a site specific estimate of the costs of the preferred solution, using the Business Planning and Consolidation (BPC) tool outlined in Attachment 5.03 of our original proposal.

The direct cost cash flow for the project is outlined in the table below.

Table 11. Project direct cost cash flow ($m, real FY19)

	Previous years	2019-20	2020-21	2021-22	2022-23	2023-24	Later years
Network Option	-	0.0	0.3	2.0	3.3	0.4	-