Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Capalaba Network Area

Final Project Assessment Report

10 October 2024

energex
Part of Energy Queensland

EXECUTIVE SUMMARY

About Energex

Energex Limited (Energex) is a subsidiary of Energy Queensland Limited and manages the electricity distribution network in the growing region of South East Queensland which includes the major urban areas of Brisbane, Gold Coast, Sunshine Coast, Logan, Ipswich, Redlands and Moreton Bay. Our electricity distribution area runs from the NSW border north to Gympie and west to the base of the Great Dividing Range.

Our electricity network consists of approximately 54,200 kilometres of powerlines and 680,000 power poles, along with associated infrastructure such as major substations and power transformers.

Today, we provide distribution services to more than 1.4 million domestic and business connections, delivering electricity to a population base of around 3.4 million people.

Identified Need

Capalaba 33/11kV Zone Substation (SSCPB) is located approximately 15km South-East of Brisbane city. The substation is supplied by three 33kV feeders from Cleveland 110/33kV Bulk Supply Substation (SSCVL) via Capalaba South 33/11kV Zone Substation (SSCPS), Birkdale 33/11kV Zone Substation (SSBKD) and Raby Bay 33/11kV Zone Substation (SSRBY). SSCPB provides electricity to approximately 3,300 predominantly residential customers and 700 commercial/industrial customers in the surrounding area.

SSCPB is equipped with two 33/11kV transformers, 33kV outdoor switchgear, 11kV indoor switchgear and control building.

An engineering assessment of Capalaba zone substation has identified that the 33/11kV power transformer TR1, 33kV outdoor type circuit breakers, 33kV outdoor type isolators, 11kV indoor switchgear, protection relays and two station transformers are at the end of their serviceable life.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the substation and the general public, as well as reliability risk to the customers supplied from Capalaba zone substation.

Approach

The National Electricity Rules (NER) require that, subject to certain exclusion criteria, network business investments for meeting service standards for a distribution business are subject to a Regulatory Investment Test for Distribution (RIT-D). Energex has determined that network investment is essential in this case for it to continue to provide electricity to the consumers in the Capalaba supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

Energex published a Draft Project Assessment Report for the above described network constraint on 16 August 2024. No submissions were received by the closing date of 27 September 2024.

Three potentially feasible options have been investigated:

- **Option A:** Replace end of life TR1, 33kV and 11kV switchgear
- **Option B:** Recover TR1, replace 33kV and 11kV switchgear and establish new 11kV tie to SSCPS
- **Option C:** Establish four new 11kV feeders from SSCPS to feed SSCPB 11kV area and recover all equipment at SSCPB

Energex's preferred option to address the identified need is Option A – Replace end of life TR1, 33kV and 11kV switchgear.

This Final Project Assessment Report has been prepared in accordance with the requirements of clause 5.17.4 of the NER.

CONTENTS

1. INTRODUCTION

This Final Project Assessment Report (FPAR) has been prepared by Energex in accordance with the requirements of clause 5.17.4 of the NER.

This FPAR represents the final stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need for the Capalaba network area.

In preparing this RIT-D, Energex is required to consider reasonable future scenarios. With respect to major customer loads and generation, Energex has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Energex is aware of are in different stages of progress and are subject to change (including outcomes where none or all proceed). These and other customer activity can occur over the consultation period and may change the timing and/or scope of any proposed solutions.

1.1. Response to the DPAR

Energex published a Draft Project Assessment Report (DPAR) for the identified need in the Capalaba network area on the 16 August 2024. No submissions were received by the closing date of the 27 September 2024.

1.2. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the Capalaba area.
- Identifies the need which Energex is seeking to address, together with the assumptions used in identifying and quantifying that need.
- Describes the credible options that are considered in this RIT-D assessment.
- Quantifies costs and classes of material market benefits for each of the credible options.
- Quantifies the applicable costs for each credible option, including a breakdown of operating and capital expenditure.
- Describes the methods used in quantifying each class of market benefit.
- Provides details of classes of market benefits that are not considered material to this RIT-D assessment and provides explanations as to why these classes of market benefits are not considered material.
- Provides the results of Net Present Value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.

1.3. Dispute Resolution Process

In accordance with the provisions set out in clause 5.17.5 of the NER, Registered Participants and other interested stakeholders may, within 30 days after the publication of this report, dispute the conclusions made by Energex in this report with the Australian Energy Regulator. Any parties raising a dispute are also required to notify Energex. Dispute notifications should be sent to demandmanagement@energex.com.au

If no formal dispute is raised, Energex will proceed with the preferred option to replace end of life TR1, 33kV and 11kV switchgear at Capalaba zone substation.

1.4. Contact Details

For further information and inquiries please contact:

E: demandmanagement@energex.com.au
P: 13 74 66

2. BACKGROUND

2.1. Geographic Region

Capalaba 33/11kV Zone Substation (SSCPB) is located approximately 15km South-East of Brisbane city. The substation provides electricity supply to approximately 3,300 residential customers and 700 commercial/industrial customers in the Capalaba, Capalaba West, Chandler and Birkdale areas, the maximum recorded demand was 16.5 MVA in Summer 2022/23.

The geographical location of Energex's sub-transmission network and substations in the area is shown in Figure 1.

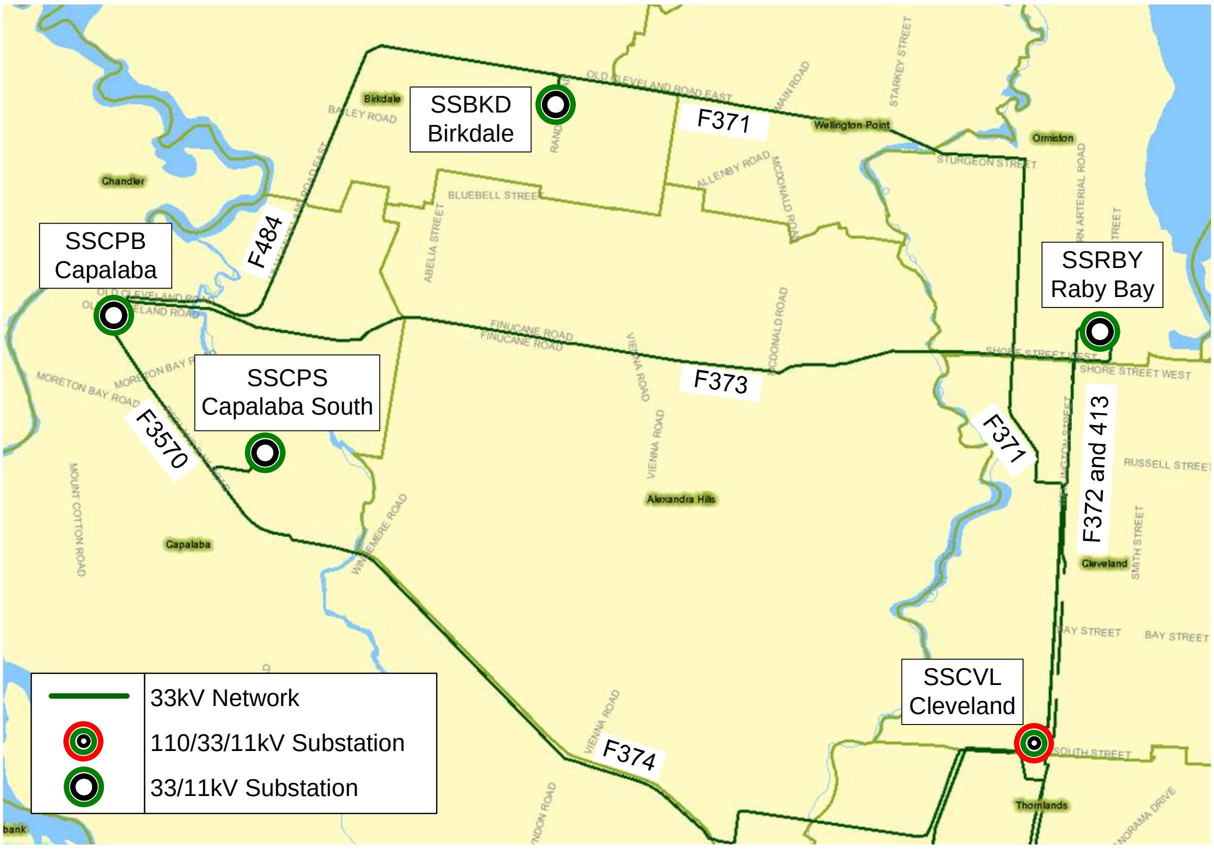


Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

The substation is supplied by Cleveland 110/33kV Bulk Supply Substation (SSCVL) via three 33kV feeders, F373, F484 and F3570 from Raby Bay 33/11kV Zone Substation (SSRBY), Birkdale 33/11kV Zone Substation (SSBKD) and Capalaba South 33/11kV Zone Substation (SSCPS), respectively.

SSCPB is equipped with a 12.5MVA 33/11kV transformer TR1, 25MVA 33/11kV transformer TR3, 33kV outdoor switchyard with steel structures, 11kV indoor switchgears and control building.

33kV outdoor switchyard contains two transformer CBs, three feeder CBs, four VTs and ten isolators. The 11kV indoor switchgear contains three 11kV transformer CBs, nine feeder CBs and two bus section CBs.

There are two 50kVA 33/0.415kV station transformers supplied off the 33kV bus at Capalaba zone substation.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 2 and the geographic view of Capalaba zone substation is illustrated in Figure 3.

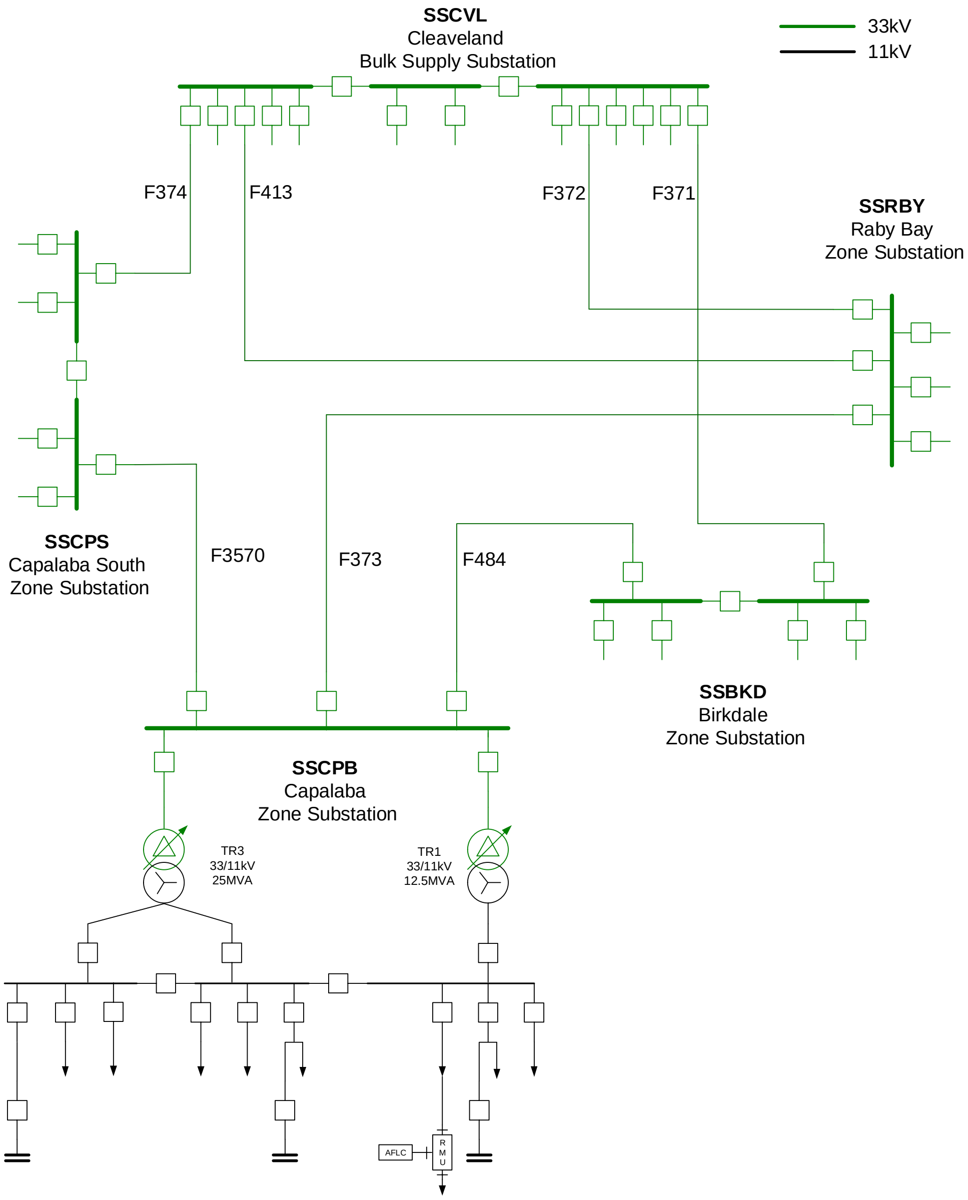


Figure 2: Existing network arrangement (schematic view)

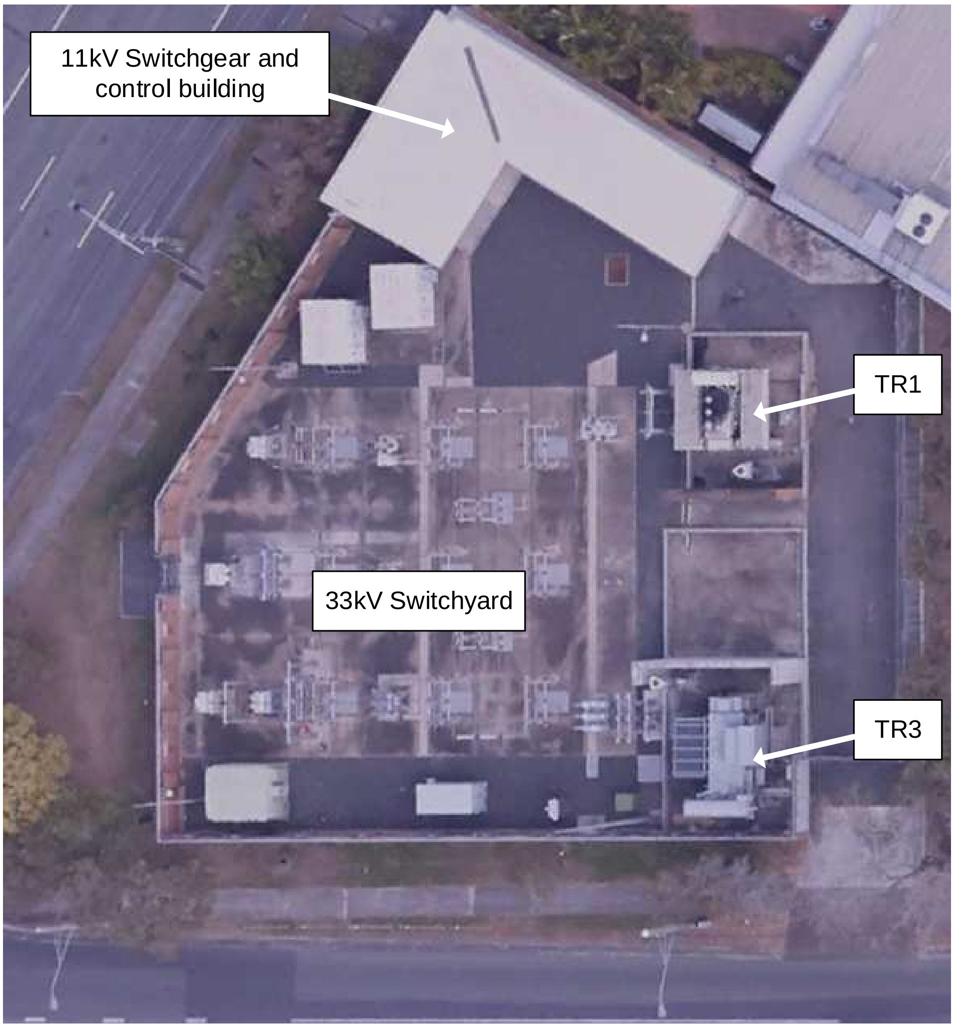


Figure 3: Capalaba zone Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at Capalaba zone substation comprises a mix of residential and business customers. The load is summer peaking, and the annual peak loads are predominantly driven by residential loads.

2.3.1. Full Annual Load Profile

The full annual load profile for Capalaba zone substation over the 2022/23 financial year is shown in Figure 4. It can be noted that the peak load occurs during summer.

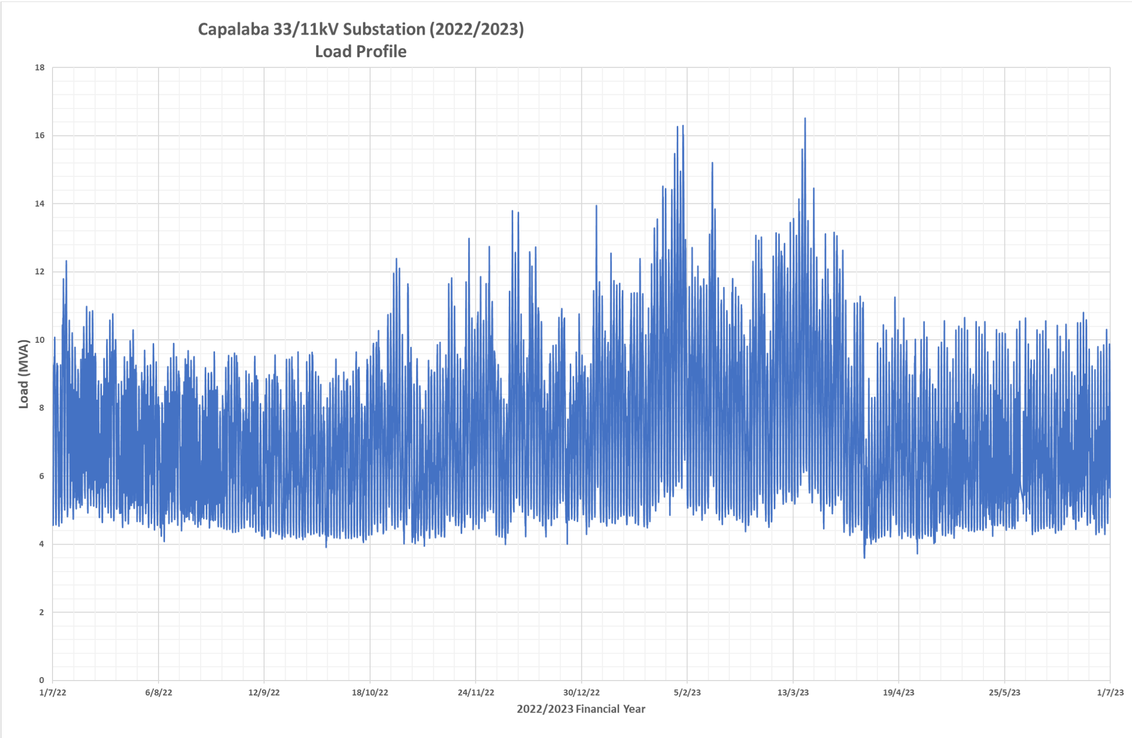


Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for Capalaba zone substation over the 2022/23 financial year is shown in Figure 5.

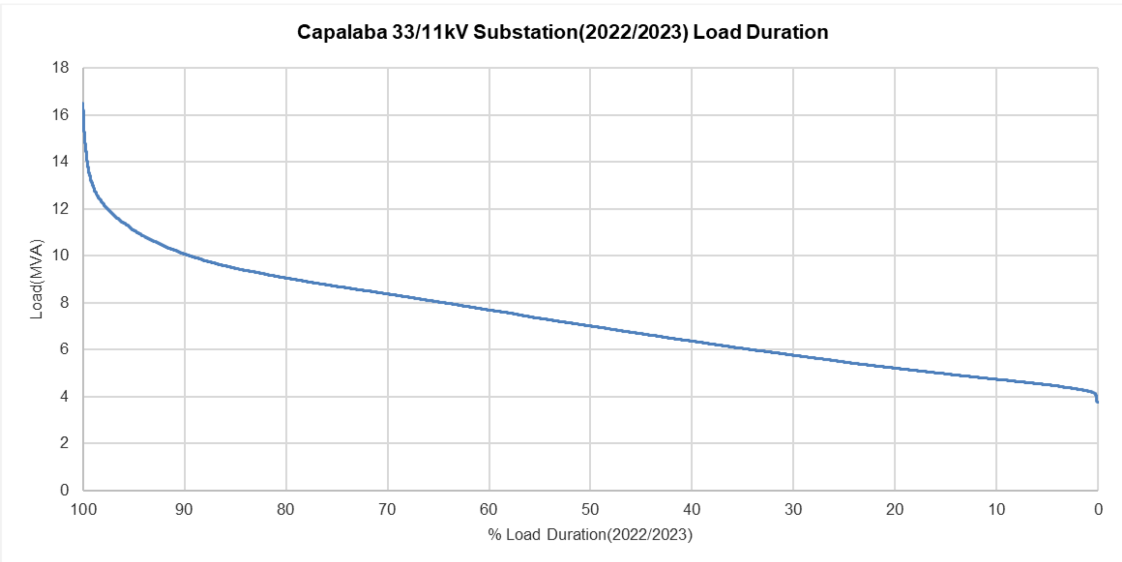


Figure 5: Substation load duration curve

2.3.3. Average Peak Weekday Load Profile (Summer)

The daily load profile for an average peak weekday during summer is illustrated below in Figure 6. It can be noted that the summer peak loads at Capalaba zone substation are historically experienced in the late afternoon and evening.

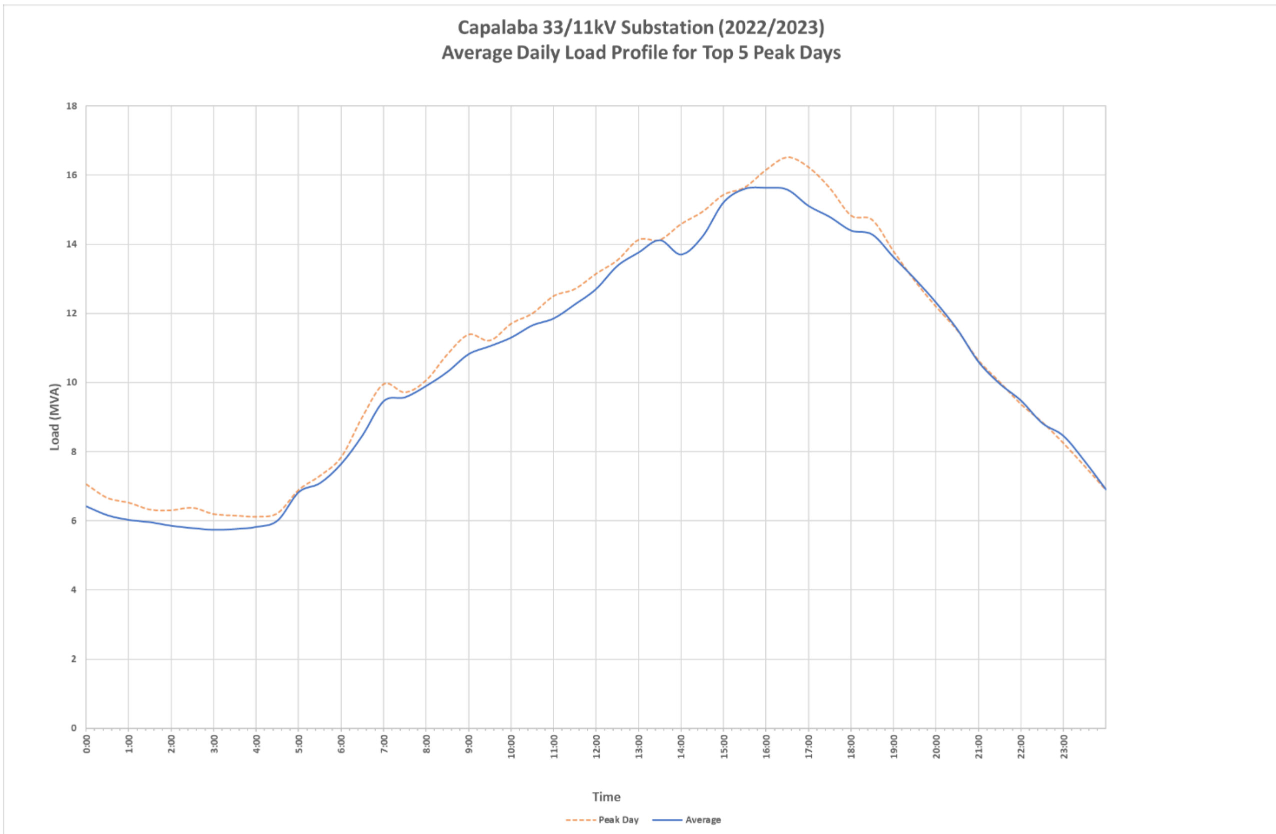


Figure 6: Substation average peak weekday load profile (summer)

2.3.4. Base Case Load Forecast

The 10 PoE and 50 PoE load forecasts for the base case load growth scenario are illustrated in Figure 7. The historical peak load for the past six years has also been included in the graph.

It can be noted that the historical annual peak loads have remained relatively steady over the past six years. It can also be noted that the peak load is forecast to remain relatively steady over the next 10 years under the base case scenario.

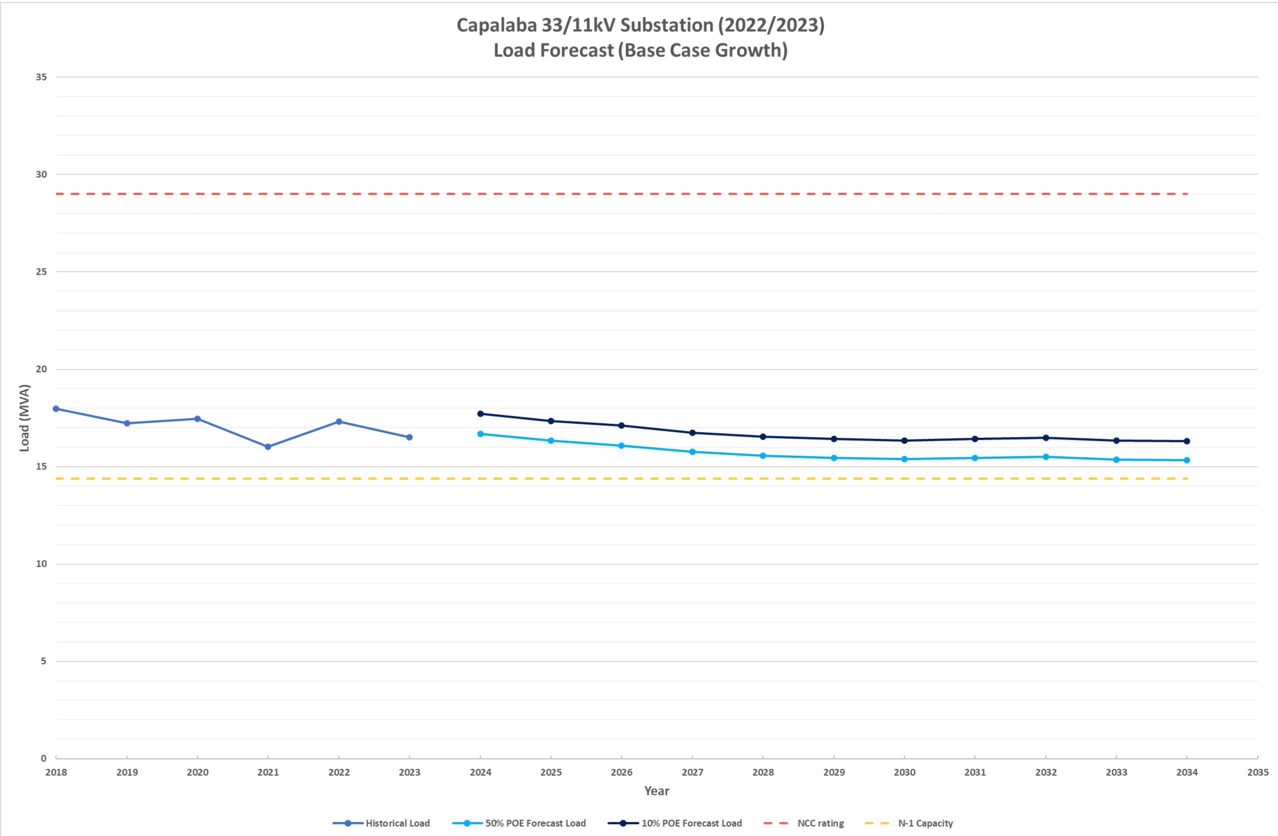


Figure 7: Substation base case load forecast

2.3.5. High Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the high load growth scenario are illustrated in Figure 8. With the high growth scenario, the peak load is forecast to remain relatively steady over the next 10 years.

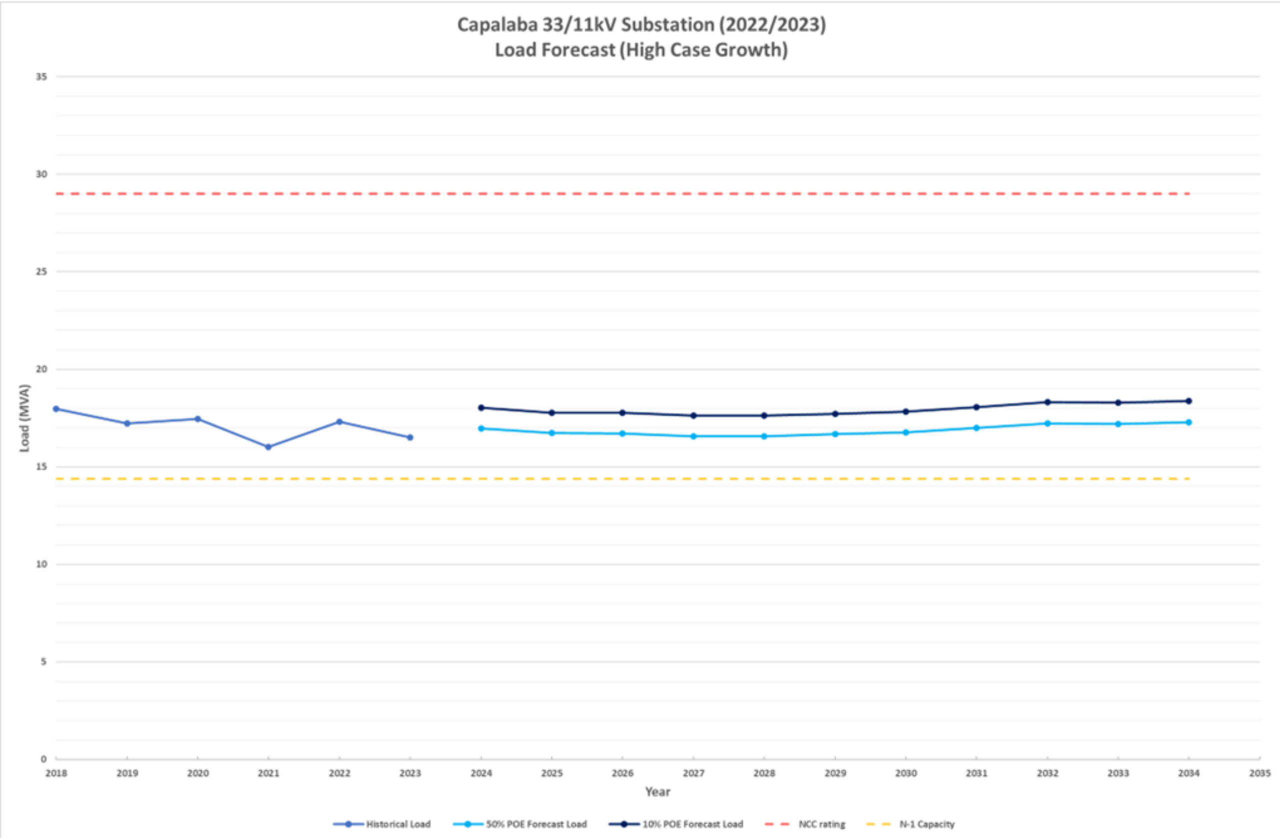


Figure 8: Substation high growth load forecast

2.3.6. Low Growth Load Forecast

The 10 PoE and 50 PoE load forecasts for the low load growth scenario are illustrated in Figure 9. With the low growth scenario, the peak load is forecast to slightly decrease over the next 10 years.

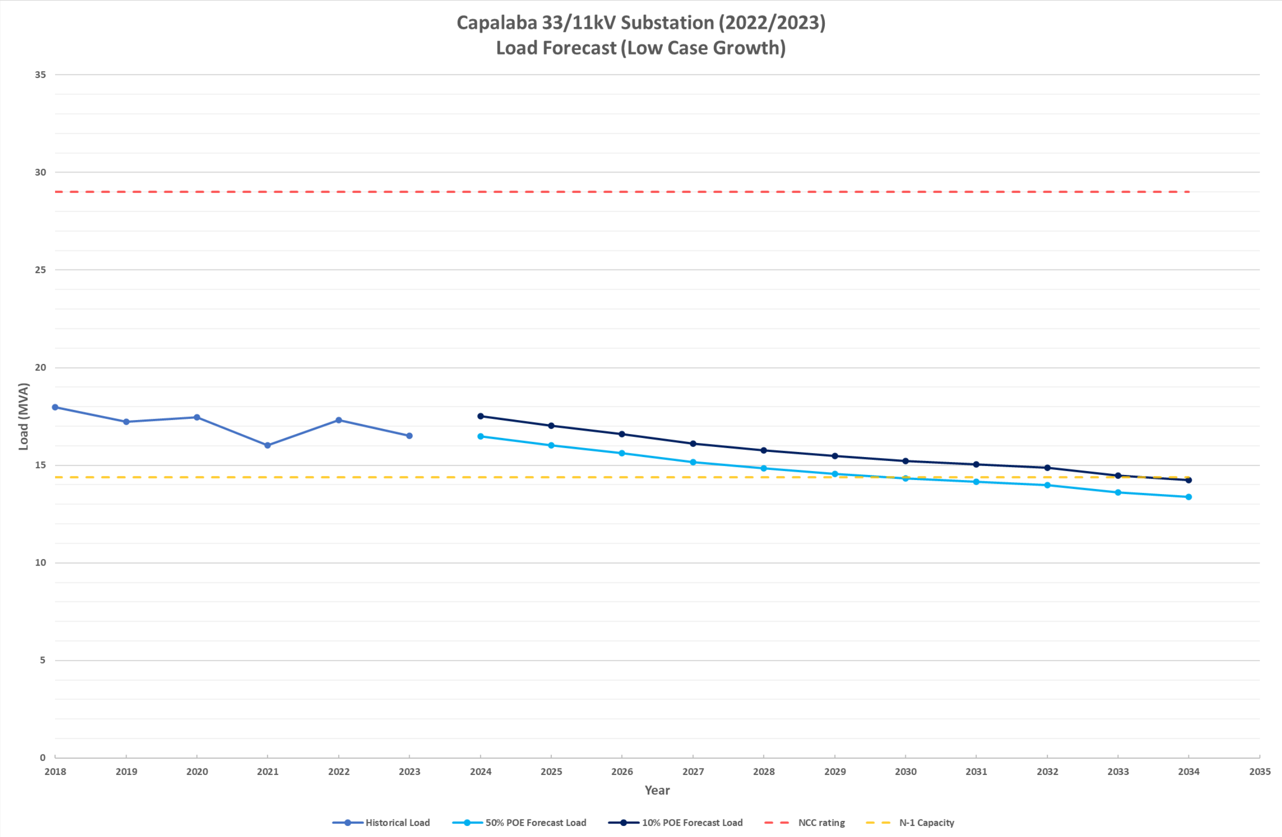


Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Reliability Corrective Action

A recent condition assessment has highlighted that a number of critical assets at SSCPB are at end of life and are in poor condition. The condition of these assets presents a considerable safety and reliability risk.

Condition data indicates that the following assets are reaching end of life:

- One 33/11kV transformer
- Three 33kV circuit breaker
- Seven 33kV isolators
- Six 11kV circuit breakers
- Two station service transformers
- Twenty-one protection relays
- One battery charger

Deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard. It also poses a safety risk to the general public, through the increased likelihood of protection relays mal-operation and catastrophic failure of the power transformers. Additionally, the poor condition of these assets significantly increases the likelihood of outages, resulting in a reduction in the level of reliability experienced by the customers supplied from Capalaba zone substation.

3.2. Quantification of the Identified Need

3.2.1. Risk Quantification Benefit Summary

Risk quantification analysis has been completed for the counter-factual scenario, which in this case is continuing the use of the existing assets with ongoing maintenance and operation. The risks include the Value of Customer Reliability (VCR), Customer Export Curtailment Value (CECV), cost of emergency replacement and safety. Figure 10 shows the annualised risks of continuing operation of the existing assets with ongoing maintenance and replacement on failure.

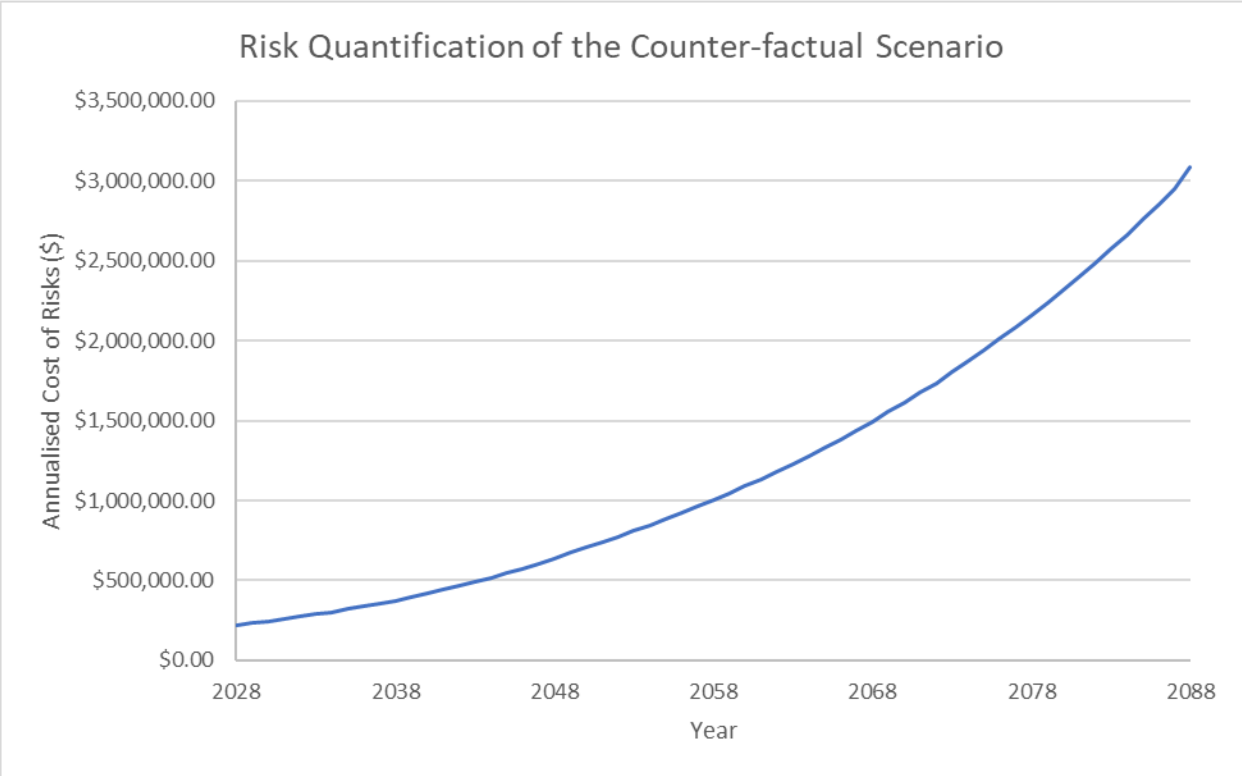


Figure 10: Risk Quantification of the Counter-factual

3.3. Assumptions in Relation to Identified Need

Below is a summary of key assumptions that have been made when the identified need has been analysed and quantified.

It is recognised that the below assumptions may prove to have various levels of correctness, and they merely represent a 'best endeavours' approach to predict the future identified need.

3.3.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at Capalaba Substation will be consistent with the base case forecast outlined in Section 2.3.4.

Factors that have been taken into account when the load forecast has been developed include the following:

- load history;
- known future developments (new major customers, network augmentation, etc.);
- temperature corrected start values (historical peak demands); and
- forecast growth rates for organic growth.

3.3.2. Load Profile

Characteristic peak day load profiles shown in Section 2.3.3 are unlikely to change significantly from year to year and the shape of the load profile is assumed to remain virtually the same with increasing maximum demand.

4. CREDIBLE OPTIONS ASSESSED

4.1. Assessment of Network Solutions

Energex has identified three credible network options that would address the identified need, are commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

4.1.1. Option A: Replace end of life TR1, 33kV and 11kV switchgear

This option includes the following works to address the identified need:

- Recover the existing 12.5MVA 33/11kV transformer
- Recover the existing 33kV outdoor oil circuit breakers, isolators and bus
- Recover the existing 11kV indoor switchgear
- Recover the existing two station transformers
- Establish a new switchgear and control building
- Install a new 25MVA 33/11kV transformer
- Install new 33kV and 11kV indoor switchgear
- Install a 33/0.4kV station transformer and 11/0.4kV station transformer

The estimated initial capital expenditure is $13.6M, with an annual operating expenditure of $40k.

A schematic diagram of the proposed network arrangement for Option A is shown in Figure 11.

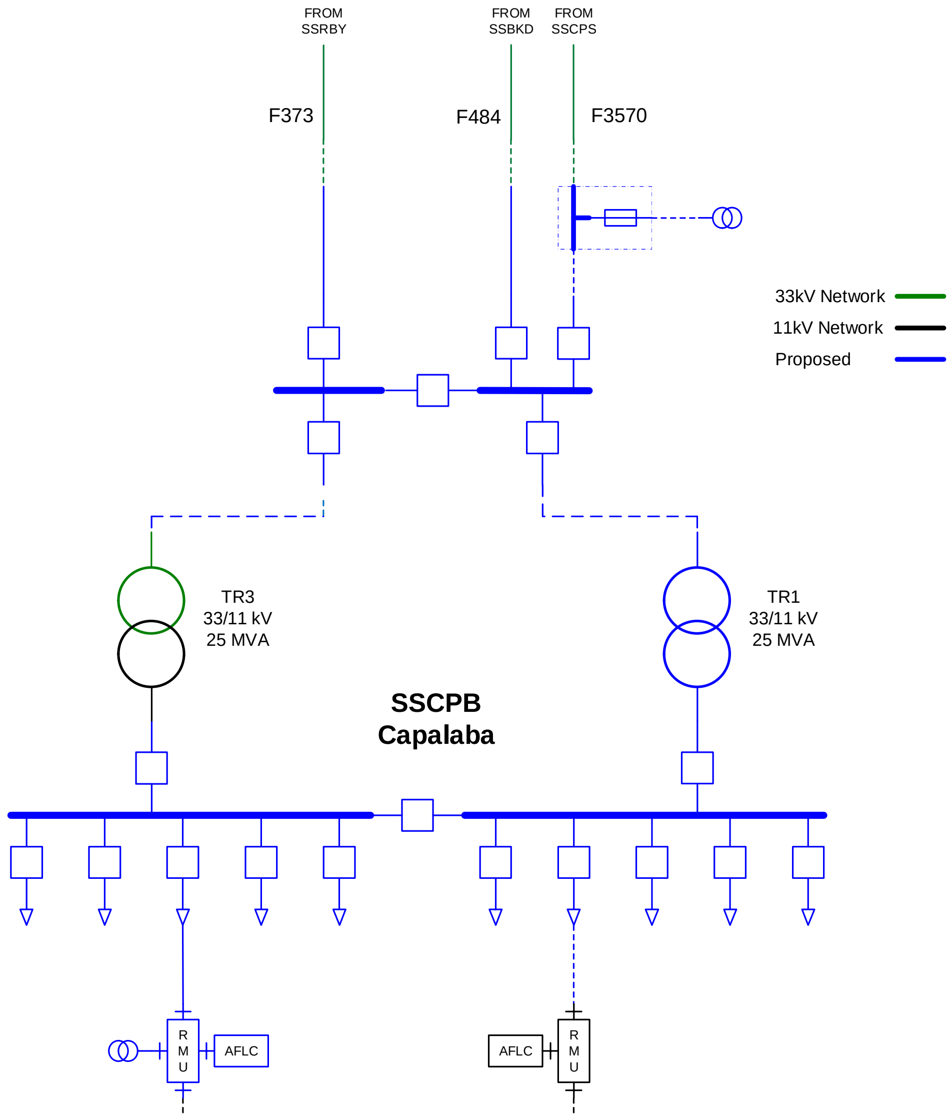


Figure 11: Option A proposed network arrangement (schematic view)

4.1.2. Option B: Recover TR1, replace 33kV and 11kV switchgear and establish new 11kV tie to SSCPS

This option includes the following works to address the identified need:

- Recover the existing 12.5MVA 33/11kV transformer
- Recover the existing 33kV outdoor oil circuit breakers and bus
- Recover the existing 11kV indoor switchgear
- Recover the existing two station transformers
- Establish a new switchgear and control building
- Install new 33kV and 11kV indoor switchgear
- Install a mobile substation connection kiosk
- Install a 33/0.4kV station transformer and 11/0.4kV station transformer
- Install an AFLC.
- Establish a new 11kV feeder from SSCPS

The estimated initial capital expenditure is $12.8M, with an annual operating expenditure of $40k.

A schematic diagram of the proposed network arrangement for Option B is shown in Figure 12.

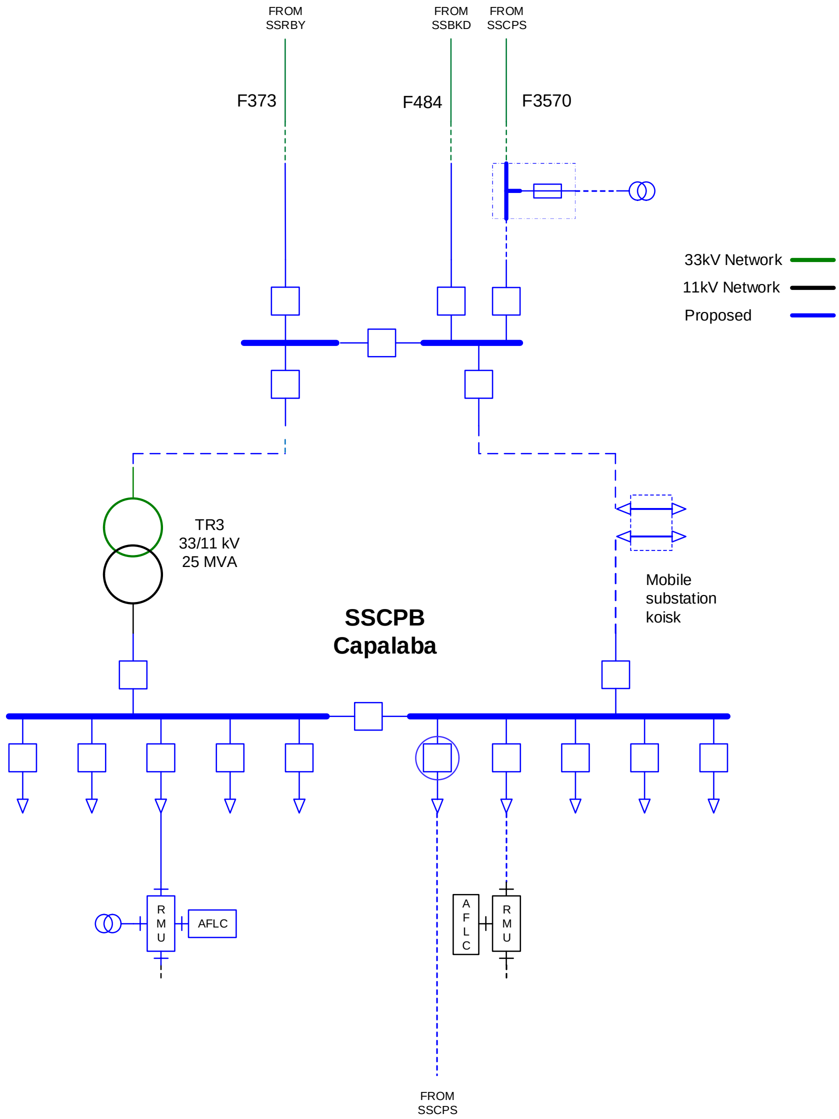


Figure 12: Option B proposed network arrangement (schematic view)

4.1.3. Option C: Establish four new 11kV feeders from SSCPS to feed SSCPB 11kV area and recover all equipment at SSCPB

This option includes the following works to address the identified need:

- Recover the existing 12.5MVA 33/11kV transformer
- Recover the existing 33kV outdoor oil circuit breakers and bus
- Recover the existing 11kV indoor switchgear
- Recover the existing two station transformers
- Establish new 33kV bus work to tie F373, F484, F3570 together at SSCPB to form a 3-ended tee-feeder.
- Establish four new 11kV feeders from SSCPS

The estimated initial capital expenditure is $6.2M, with an annual operating expenditure of $5k.

This option will require the re-establishment of SSCPB in the future due to load growth.

A schematic diagram with the proposed network arrangement for Option C is shown in Figure 13.

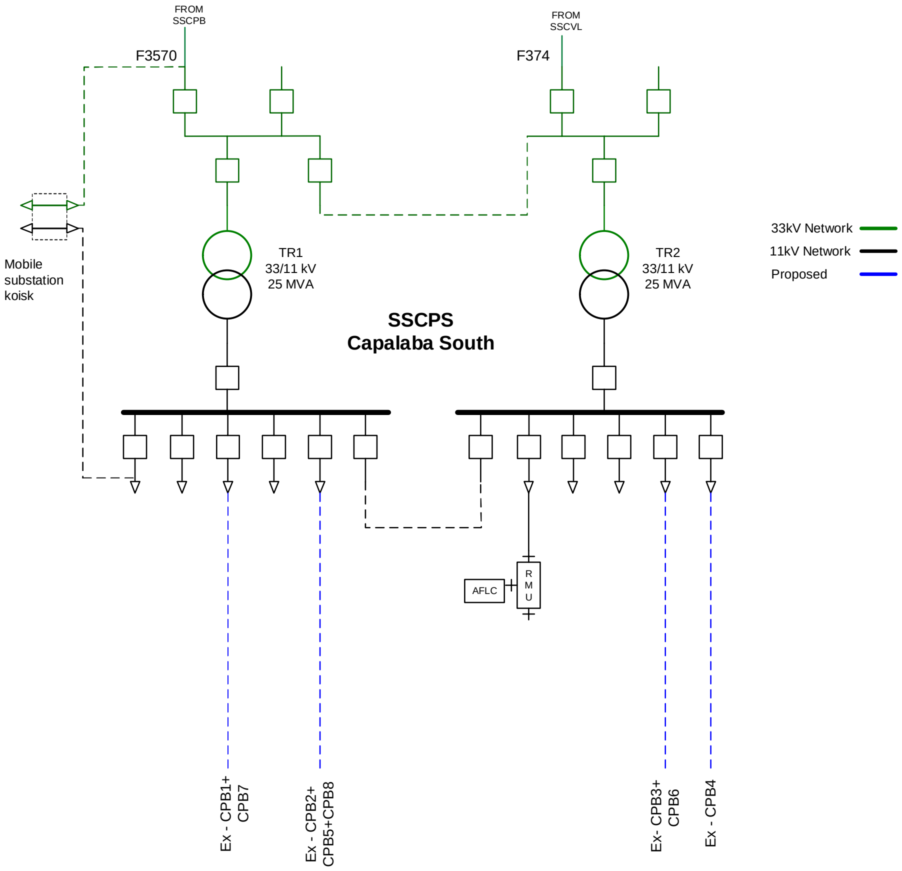


Figure 13: Option C proposed network arrangement (schematic view)

4.2. Assessment of SAPS and Non-Network Solutions

Energex has considered Standalone Power Systems (SAPS) and demand management solutions to determine their feasibility to meet the identified need. Each of these are considered below.

4.2.1. Consideration of SAPS Options

Energex considers there is no SAPS option that could form a potential credible option on a standalone basis, or that could form a significant part of the credible option. In particular the load requirements, per the forecast in the Capalaba supply area, could not be supported by a network that is not part of the interconnected national electricity system.

4.2.2. Demand Management (Demand Reduction)

Energex's Demand & Energy Management (DEM) team has assessed the potential non-network alternative options required to defer the network option and determine if there is a viable demand management (DM) option to replace or reduce the need for the network options proposed.

Credible options must be technically and commercially viable and must be able to be implemented in sufficient time to satisfy the identified risk to the public and/or the network due to the identified constraints.

The DEM team has completed a review of the Capalaba customer base and considered a number of demand management technologies. It has been determined that there are no demand management options that are commercially and technically feasible. The options considered are explored in the following sections.

Network Load Control

The residential customers load appears to drive the daily peak demand which generally occurs between 3:00pm and 8:00pm.

There are 2,117 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 1,270kVA is available.

Therefore, network load control would not sufficiently address the identified need.

4.2.3. Demand Response

Four methods utilising demand response technology for deferring network investment are: Call Off Load (COL), Customer Embedded Generation (CEG), Large Scale Customer Generation (LSG) and customer solar power systems.

Customer Call Off Load (COL)

COL is an effective technique for deferring network investment where the need is for a short time period. However, in this instance, the need is required on a long-term permanent basis. There are a small number of large customers in the catchment area but the $/kVA funding available for demand reduction is low therefore customer call off load has been assessed as not a viable proposition as it will not address the identified need, nor benefit the community.

Customer Embedded Generation (CEG)

CEG is an effective technique for deferring network investment where the need is for a short time period. The identified need in this instance is in relation to reliability and safety. A short-term deferral of network investment by using CEG is not a technically or financially feasible option (due to the number of contracts required to be negotiated and managed).

This option has been assessed as technically not viable as it would not address the identified need.

Large-Scale Customer Generation (LSG)

LSG sites such as renewable energy generation, solar or wind farms of multiple MW's capacity constitute an opportunity to support substation investment by reducing demand on, and potentially providing reactive power support for substation assets.

This option could potentially address the identified need, however, has been assessed as technically not viable as there is no known existing or proposed LSG demand response available.

Customer Solar Power Systems

A total of 1,283 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 7,995kVA.

The daily peak demand is driven by residential customer demand and the peak generally occurs between 3:00pm and 8:00pm. As such customer solar generation does not coincide with the peak load period.

Business customers with large solar arrays are deemed to present a significant opportunity for targeted load control or load curtailment if coupled with a Battery Energy Storage System (BESS). Contracting such customers is attractive as they represent a larger load across fewer customers and therefore are cheaper and easier to engage and contract.

However, only a small percentage of customers in this supply area have solar PV systems and possibly none have a BESS. PV systems with BESS present a future portfolio opportunity for potential demand response but currently this supply area has very limited solar/BESS. Solar customers without a BESS will not meet the technical needs of the demand reduction as their solar contribution may not be available when the network un-met need is required.

4.2.4. SAPS and Non-Network Solution Summary

Energex has not identified any viable SAPS or non-network solutions that will provide a complete or a hybrid (combined network and non-network) solution to provide the magnitude of network support required in the Capalaba area to address the identified need.

4.3. Preferred Option

Energex's preferred option is Option A, to replace existing end of life transformers, 33kV and 11kV switchgear at Capalaba zone substation.

Upon completion of these works, the asset safety and reliability risks at Capalaba zone substation will be addressed as the deteriorated and poorly performing assets will be removed from service. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources. This option will address the identified need, are commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

The estimated capital cost of this option is $13.6 million. Annual operating and maintenance costs are anticipated to be $40k. The estimated project delivery timeframe has design commencing in February 2025 and construction completed by February 2029.

5. SUMMARY OF SUBMISSIONS RECEIVED IN RESPONSE TO DRAFT PROJECT ASSESSMENT REPORT

On 16 August 2024, Energex published the Draft Project Assessment Report providing details on the identified need on the Capalaba zone substation assets end of life replacement. This report provided both technical and economic information about possible solutions and sought information from interested parties about possible alternate solutions to address the need for investment.

In response to the Draft Project Assessment Report, Energex received no submissions by 27 September 2024, which was the closing date for submissions to the Draft Project Assessment Report.

6. MARKET BENEFIT ASSESSMENT METHODOLOGY

The purpose of the RIT-D is to identify the option that maximises the present value of net market benefits to all those who produce, consume and transport electricity in the National Electricity Market (NEM).

In order to measure the increase in net market benefit, Energex has analysed the classes of market benefits required to be considered by the RIT-D.

6.1. Classes of Market Benefits Considered and Quantified

The following classes of market benefits are considered material, and have been included in this RIT-D assessment:

- Changes in involuntary load shedding and Customer Interruptions caused by Network Outages

6.1.1. Changes in Involuntary Load Shedding and Customer Interruptions caused by Network Outages

Involuntary load shedding is where a customer's load is interrupted from the network without their agreement or prior warning. Energex has forecast load over the assessment period and has quantified the expected unserved energy by comparing forecast load to network capabilities under system normal and network outage conditions. A reduction in involuntary load shedding expected from an option, relative to the base case, results in a positive contribution to the market benefits of the credible option being assessed.

Involuntary load shedding of a credible option is derived by the quantity in MWh of involuntary load shedding required assuming the credible option is completed multiplied by the Value of Customer Reliability (VCR). The VCR is measured in dollars per MWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D.

Energex has applied a VCR estimate of $44.7/kWh, which has been derived from the AER 2023 Value of Customer Reliability (VCR) values. In particular, Energex has weighted the AER estimates according to the make-up of the specific load considered.

Customer export Curtailment value (CECV) represents the detriment to all customers from the curtailment of DER export (e.g. rooftop solar PV systems). A reduction in curtailment due to implementing a credible option results in a positive contribution to the market benefits of that option. These benefits have been calculated according to the AER CECV methodology based on the capacity of DER currently installed and forecast to be installed within the Capalaba supply area.

6.2. Classes of Market Benefits not Expected to be Material

The following classes of market benefits are not considered to be material for this RIT-D, and have not been included in this RIT-D assessment:

- Changes in voluntary load curtailment
- Changes in costs to other parties

- Differences in timing of expenditure
- Changes in load transfer capacity and the capacity of Embedded Generators to take up load
- Changes in electrical energy losses
- Changes in Greenhouse Gas emissions
- Option value
- Other Classes of Market Benefit

6.2.1. Changes in Voluntary Load Curtailment

The credible options presented in this RIT-D assessment do not include any voluntary load curtailment as there are no customers on voluntary load curtailment agreements in the Capalaba area. Therefore, market benefits associated with changes in voluntary load curtailment have not been considered.

6.2.2. Changes in Costs to Other Parties

Energex does not anticipate that any of the credible options included in this RIT-D assessment will affect costs incurred by other parties.

6.2.3. Differences in Timing of Expenditure

The credible options included in this RIT-D assessment are not expected to affect the timing of other distribution investments for unrelated identified needs.

6.2.4. Changes in Load Transfer Capacity and the capacity of Embedded Generators to take up load

The credible options included in this RIT-D assessment are not expected to have an impact on the load transfer capacity or the capacity of embedded generators to take up load between the zone substations in the Capalaba area.

6.2.5. Changes in Electrical Energy Losses

Energex does not anticipate that any of the credible options included in the RIT-D assessment will lead to any significant change in network losses.

6.2.6. Changes in Greenhouse Gas Emissions

Energex does not anticipate that the credible options included in the RIT-D assessment will lead to any significant changes in greenhouse gas emissions.

6.2.7. Option Value

The AER's view is that option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered by the RIT-D proponent are sufficiently flexible to respond to that change[1].

Energex does not consider that the identified need for the options included in this RIT-D would be affected by uncertain factors about which there may be more clarity in future.

6.2.8. Other Class of Market Benefit

Energex has not identified any other relevant class of market benefit for this RIT-D.

6.3. Quantification of Market Benefits

The market benefits from changes in involuntary load shedding and customer interruptions caused by network outages for each option have been quantified as shown in the figures below:

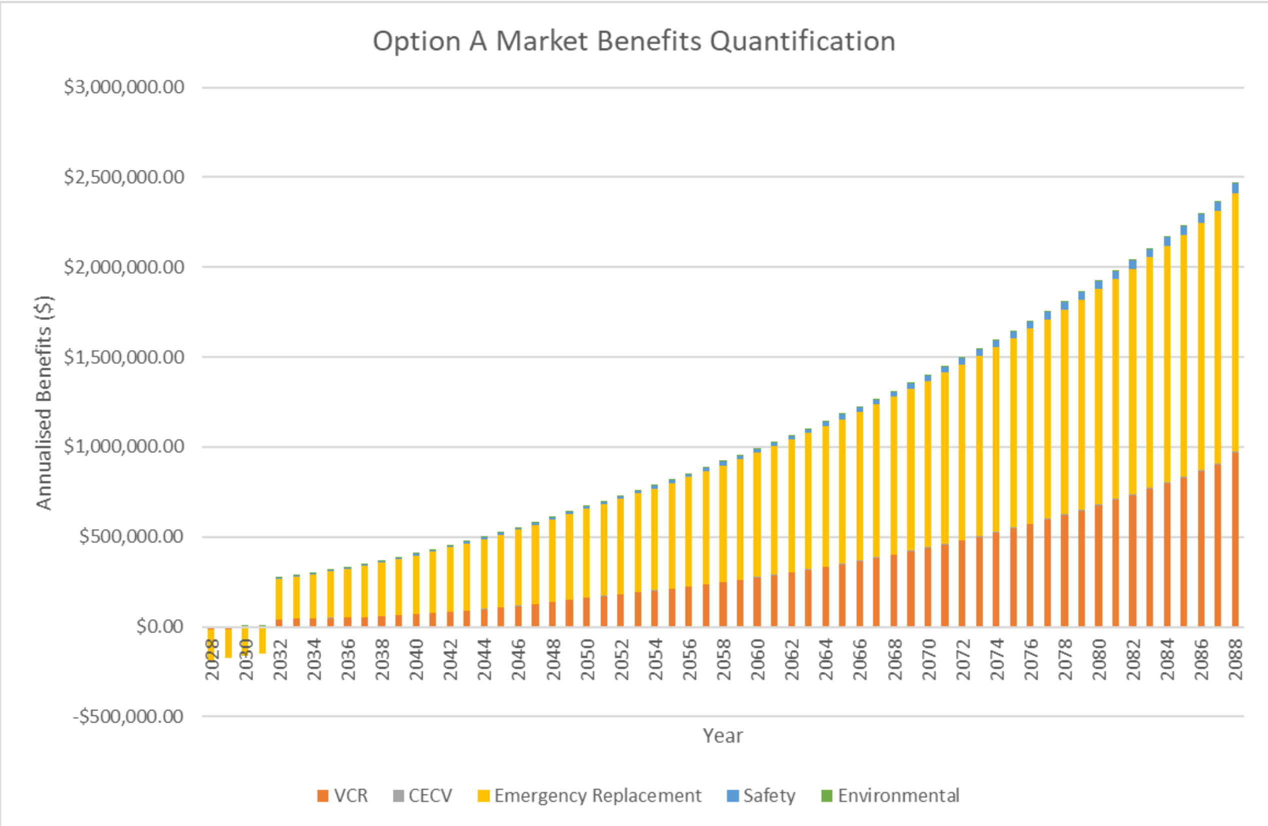


Figure 14: Option A Market Benefits

[1] AER "Regulatory Investment Test for Distribution Application Guidelines", Section A6.
Available at: http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-investment-test-for-distribution-rit-d-and-application-guidelines

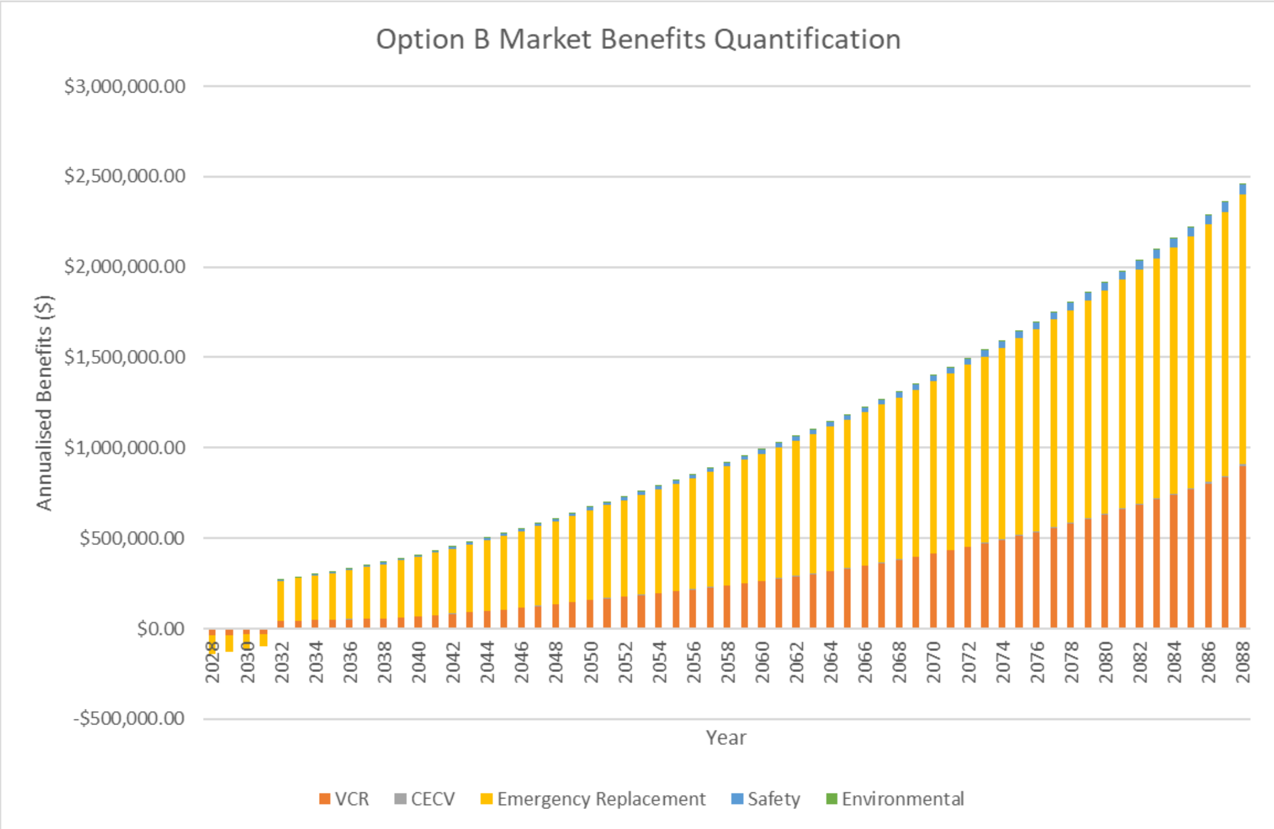


Figure 15: Option B Market Benefits

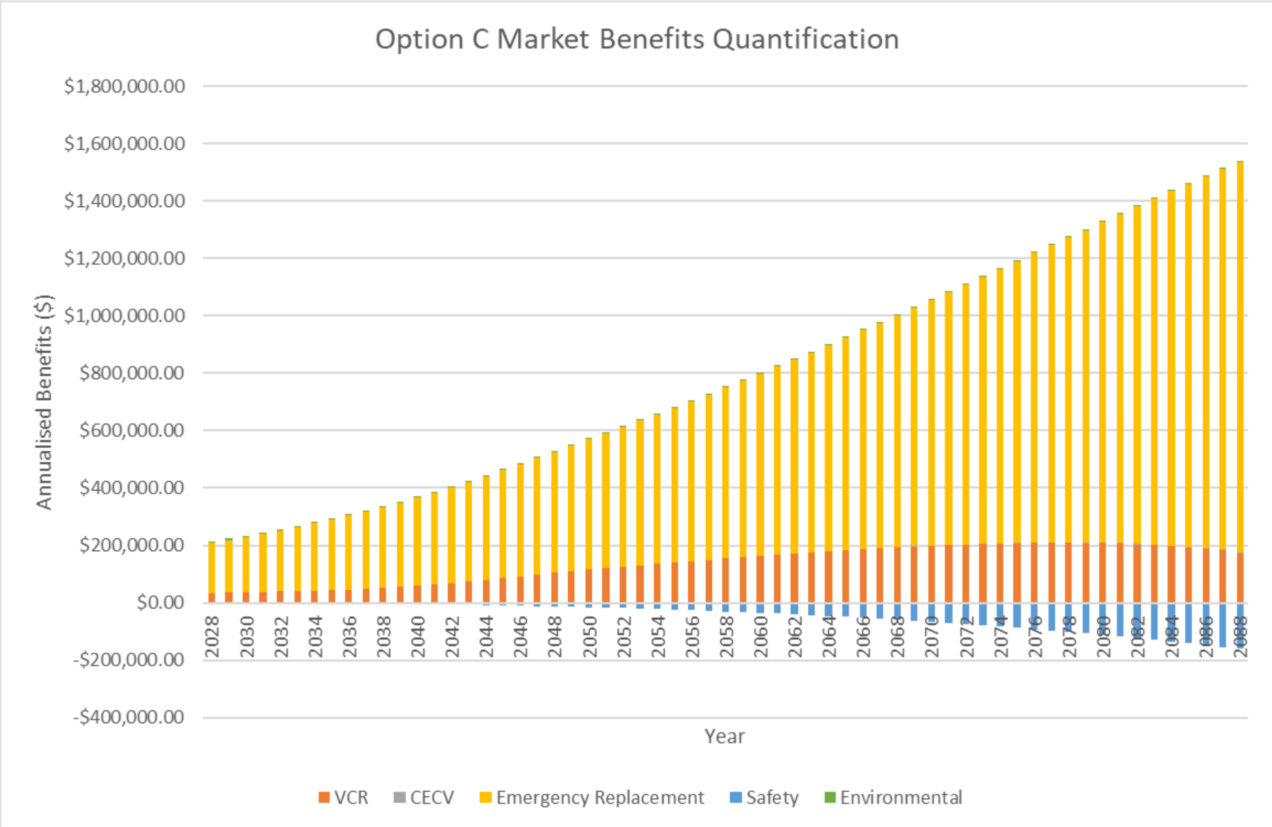


Figure 16: Option C Market Benefits

7. DETAILED ECONOMIC ASSESSMENT

7.1. Methodology

The RIT-D requires Energex to identify the credible option that maximises the present value of net economic benefit to all who produce, consume and transport electricity in the NEM.

Accordingly, a base case Net Present Value (NPV) comparison of each credible option has been undertaken. A sensitivity analysis was then conducted on this base case to establish the option that remained the lowest cost option in the scenarios considered.

Further to the scenarios considered, a Monte-Carlo analysis simulation was undertaken on the base case project timings to assess the projects sensitivity to a change in the parameters of the NPV model.

7.2. Key Variables and Assumptions

The economic assessment contains anticipated costs of providing, operating and maintaining the options as well as expected costs of compliance and administration associated with each option.

The present value comparison summary includes all costs directly associated with constructing and providing the option. This includes the cost of land and easements currently owned or to be acquired for network augmentation.

Interest on borrowings is not included as a cost in the comparison of options as it represents a cost of project financing, and as such is accounted for in present value calculations through the discounting of the project cash flows at the regulated WACC.

Table 1 outlines the major sensitivities analysed within the Monte-Carlo analysis which was undertaken to assess the sensitivity to a change in parameters of the NPV model.

Parameter	Mode Value	Lower Bound	Upper Bound
Project Costs	Standard estimates	-40%	+40%
Project Costs	Preferred option estimates	-40%	+40%
Opex Costs	Calculated Opex	-10%	+10%

Table 1: Economic parameters and sensitivity analysis factors

7.3. Scenarios Adopted for Sensitivity Testing

A sensitivity analysis was conducted on the base case to establish the option that remained the lowest cost option in the scenarios considered. In this instance, the scenarios that have been considered are:

1. **Medium demand** – under this scenario the existing load remains around the same as it currently is. This is consistent with the base case load forecast provided in SIFT. This scenario has been assigned a likelihood of 80% in the weighted average NPV.

2. **High demand** – under this scenario the only change from the Medium Growth scenario is that the high growth load forecast provided from SIFT has been used. This scenario has been assigned a likelihood of 20% in the weighted average NPV.

Low demand was not considered because the staging of projects and VCR benefit would be very similar to that of the Medium demand scenario.

7.4. Net Present Value (NPV) Results

An overview of the initial capital cost and the base case NPV results are provided in Table 2.

Option	Option Name	Rank	Initial Capital Cost	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
A	Replace end of life TR1, 33kV and 11kV switchgear	1	$13.6M	$4.2M	-$11.9M	-$0.99M
B	Recover TR1, replace 33kV and 11kV switchgear with new indoor switchgear and establish new 11kV tie to SSCPS	2	$12.8M	$3.5M	-$12.8M	-$0.99M
C	Establish four new 11kV feeders from SSCPS to feed SSCPB 11kV area and recover SSCPB	3	$6.25M	$1.5M	-$12.1M	-$0.61M

Table 2: Base case NPV ranking table

A sensitivity analysis was conducted on this base case to establish the option that remained the lowest cost option in the scenarios considered. Table 3 provides the results of the sensitivity analysis.

Option Number	Option Name	Weighted Rank	Weighted Net Economic Benefit	Weighted Capex PV	Weighted Opex PV	Initial Capex ($)
A	Replace end of life TR1, 33kV and 11kV switchgear	1	$4.9M	-$11.9M	-$0.99M	$13.6M
B	Recover TR1, replace 33kV and 11kV switchgear with new indoor switchgear and establish new 11kV tie to SSCPS	2	$4.1M	-$12.8M	-$0.99M	$12.8M
C	Establish four new 11kV feeders from SSCPS to feed SSCPB 11kV area and recover SSCPB	3	$1.4M	-$12.4M	-$0.63M	$6.25M

Table 3: Scenario Analysis - Comparison of Options

Further to the scenarios considered, a Monte-Carlo analysis simulation was undertaken on the base case project timings to assess the projects sensitivity to a change in the parameters of the NPV model. The Monte-Carlo analysis undertook 1000 simulations of all the variables. Table 4 shows the percentage of times each option was the most economical across the simulations and also the average NPV cost of all the simulations.

Option Number	Option Name	Rank 1	Rank 2	Rank 3	Average NPV
A	Replace end of life TR1, 33kV and 11kV switchgear	65.6%	29.3%	5.2%	$5.9M
B	Recover TR1, replace 33kV and 11kV switchgear with new indoor switchgear and establish new 11kV tie to SSCPS	32.4%	58.6%	9.0%	$5.1M
C	Establish four new 11kV feeders from SSCPS to feed SSCPB 11kV area and recover SSCPB	2.0%	12.2%	85.8%	$1.2M

Table 4: Monte Carlo Analysis for Base Case Forecast

Option A is the lowest cost option in the weighted average results across the two scenarios. Option A also has the lowest average cost and is the most economical in 65.6% of cases in the Monte-Carlo simulations.

Based on the detailed economic assessment, Option A is considered to provide the optimum solution to address the forecast limitations and is therefore the recommended development option.

8. CONCLUSION

The FPAR represents the final stage of the consultation process in relation to the application of the RIT-D.

Energex intends to take steps to progress the preferred option to address the identified need.

8.1. Preferred Option

Energex's preferred option is Option A, to replace existing end of life transformers, 33kV and 11kV switchgear at Capalaba zone substation.

Upon completion of these works, the asset safety and reliability risks at Capalaba zone substation will be addressed as the deteriorated and poorly performing assets will be removed from service. The preferred option will provide the greatest reliability benefit for customers, whilst also reducing expenditure on obsolete and non-compliant assets while ensuring more efficient use of design and construction resources.

The estimated capital cost of this option is $13.6 million. Annual operating and maintenance costs are anticipated to be $40k. The estimated project delivery timeframe has design commencing in February 2025 and construction completed by February 2029.

8.2. Satisfaction of RIT-D

The preferred option satisfies the RIT-D and maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM.

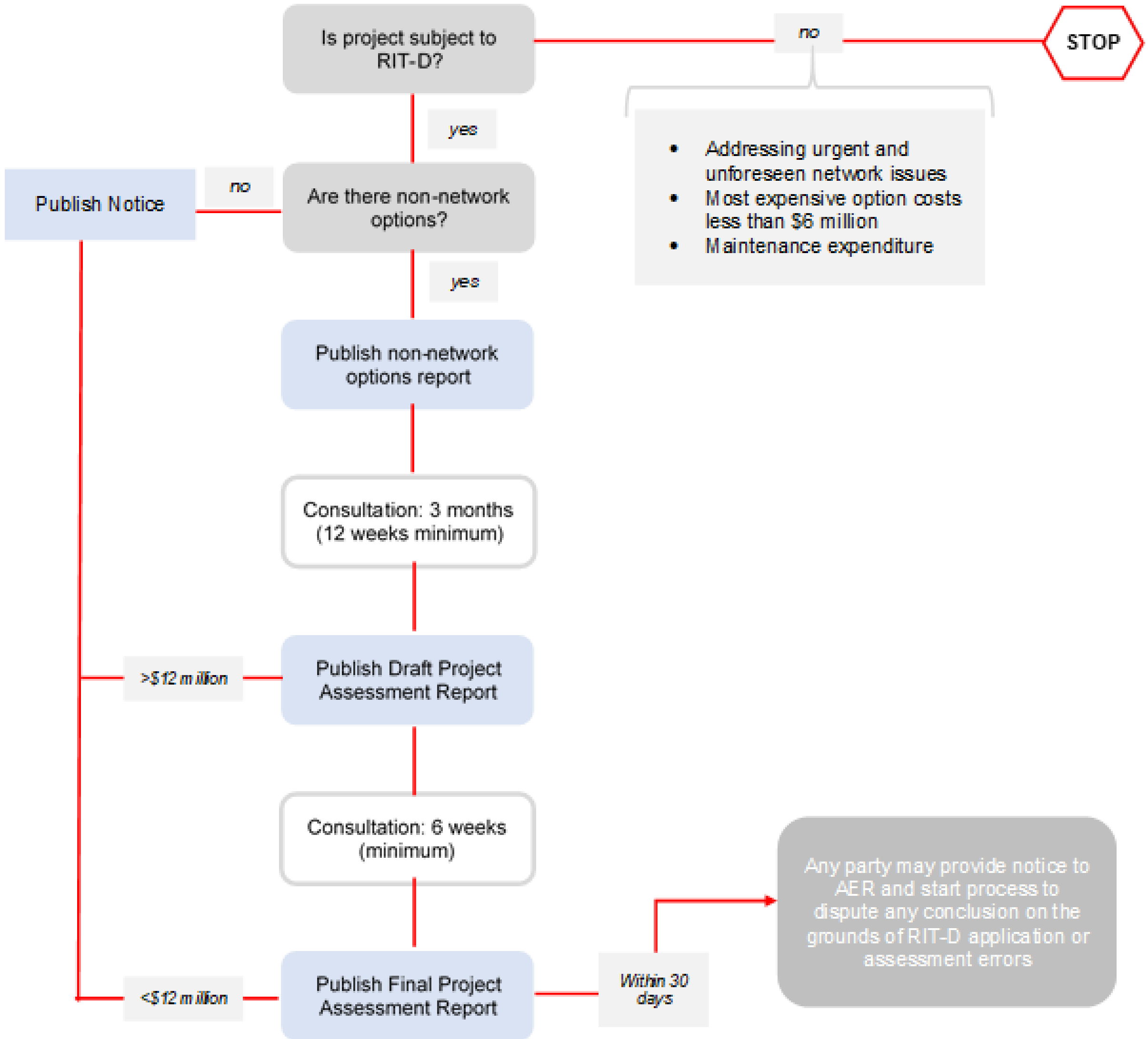
This statement is made on the basis of the detailed analysis set out in this report. The preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

9. COMPLIANCE STATEMENT

This Final Project Assessment Report complies with the requirements of NER section 5.17.4(j) as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.3
(3) if applicable, a summary of, and commentary on, the submissions received on the DPAR;	5
(4) a description of each credible option assessed	4 & 5
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	6
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	7
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	6
(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	6.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	7.4
(10) the identification of the proposed preferred option	8.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (ii) the indicative capital and operating costs (where relevant); (iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	4.1.1, 8.1 & 8.2
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.4

APPENDIX A – THE RIT-D PROCESS



Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.