Regulatory Investment Test for Distribution (RIT-D)

Addressing Reliability Requirements in the Chermside Network Area

Final Project Assessment Report

9 January 2025

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

Chermside 33/11kV zone substation (SSCSE) is being supplied by Stafford bulk supply substation (SSSFD) via two 33kV feeders 550 and 551. There is 1 x normally opened 33kV feeder to Zillmere zone substation (SSZMR).

SSCSE has a 33kV ring bus configuration with 3 x feeder circuit breakers and 3 x transformer circuit breakers. SSCSE provides electricity supply to approximately 9616 customers of which 74% are a mix of commercial and industrial, and 26% are residential in the Chermside and Wavell Heights areas.

According to Energex's Condition Based Risk Management (CBRM) assessment report, it has been identified that the 11kV switchgears on bus BB11 and bus BB12, 33/11kV transformer TR1, 33kV CB3T12, CB5512 and CB5502 are reaching end of life and require replacement.

The deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard, and reliability risk to the customers supplied from SSCSE.

Energex has a need to invest in SSCSE to maintain compliance with the Electrical Safety Act 2002 (Qld) and Energex's Distribution Authority. Without such investment, Energex may, in the event of failure of the above identified critical assets, be in breach of regulatory obligations. Therefore Energex considers that reliability and safety corrective action at SSCSE is necessary.

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 Chermside supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

Addressing Reliability Requirements in the Chermside Network Area Final Project Assessment Report

Energex published a Notice-of-Screening-for-Options Report on 10 January 2024. One potentially feasible option has been investigated:

- Option 1: Replace 11kV circuit breakers, TR1 and 33kV circuit breakers.

This Final Project Assessment Report (FPAR), where Energex provides both technical and economic information about possible solutions, 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 Chermside 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. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the Chermside 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.

1.2. 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 11kV circuit breakers, TR1, 33kV circuit breakers and protection relays at SSCSE.

1.3. Contact Details

For further information and inquiries please contact:

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

2. BACKGROUND

2.1. Geographic Region

Chermside 33/11kV zone substation (SSCSE) is supplied from Stafford bulk supply substation (SSSFD BSP). SSCSE provides electricity supply to approximately 9616 customers of which 74 % are a mix of commercial and industrial, and 26% are residential in the Chermside and Wavell Heights areas.

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

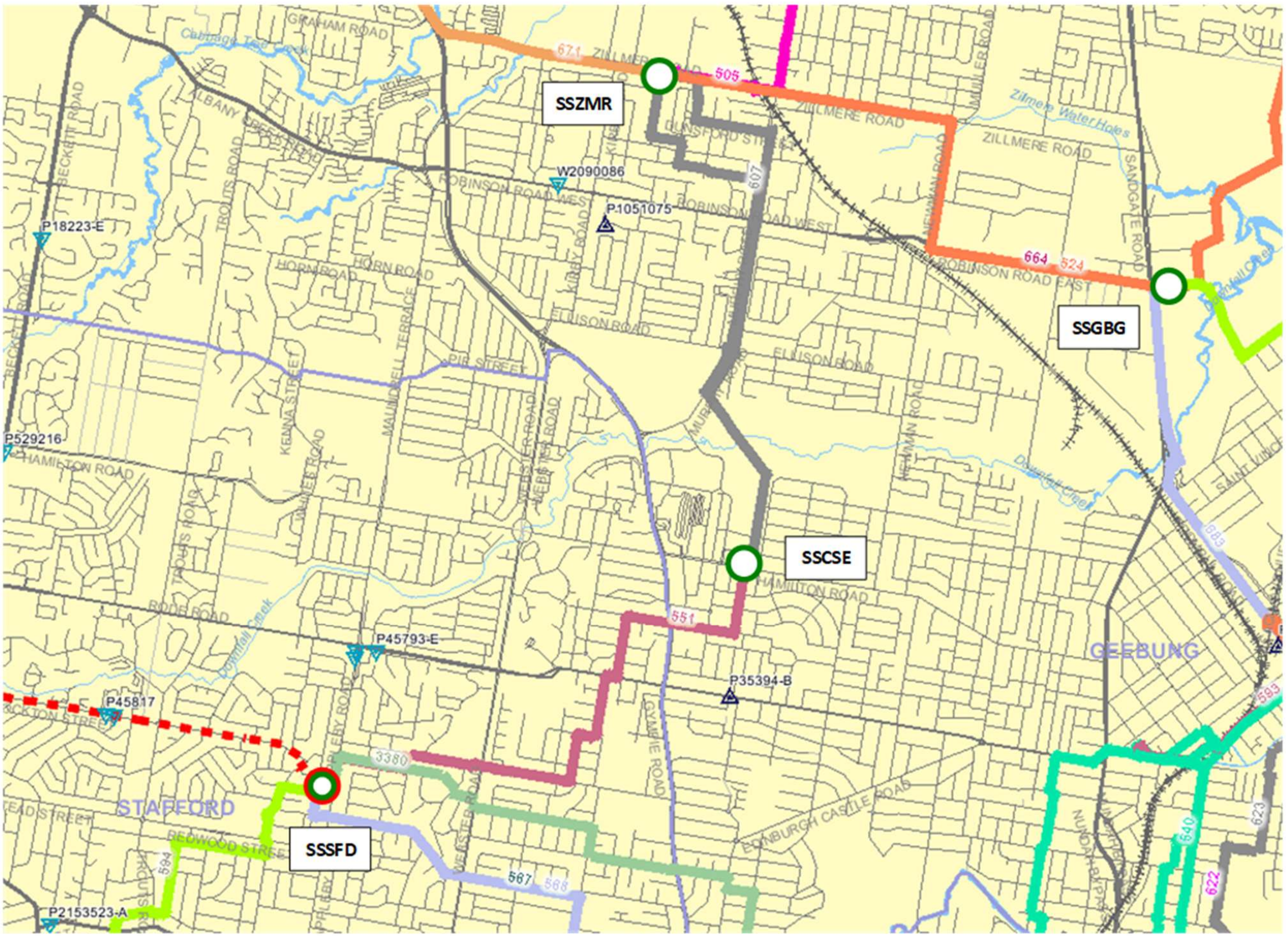


Figure 1: Existing network arrangement (geographic view)

2.2. Existing Supply System

SSCSE zone substation is being supplied by Stafford bulk supply substation (SSSFD) via two 33kV feeders 550 and 551. There is 1 x normally opened 33kV feeder to Zillmere zone substation (SSZMR).

SSCSE has a 33kV ring bus configuration with 3 x feeder circuit breakers and 3 x transformer circuit breakers.

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

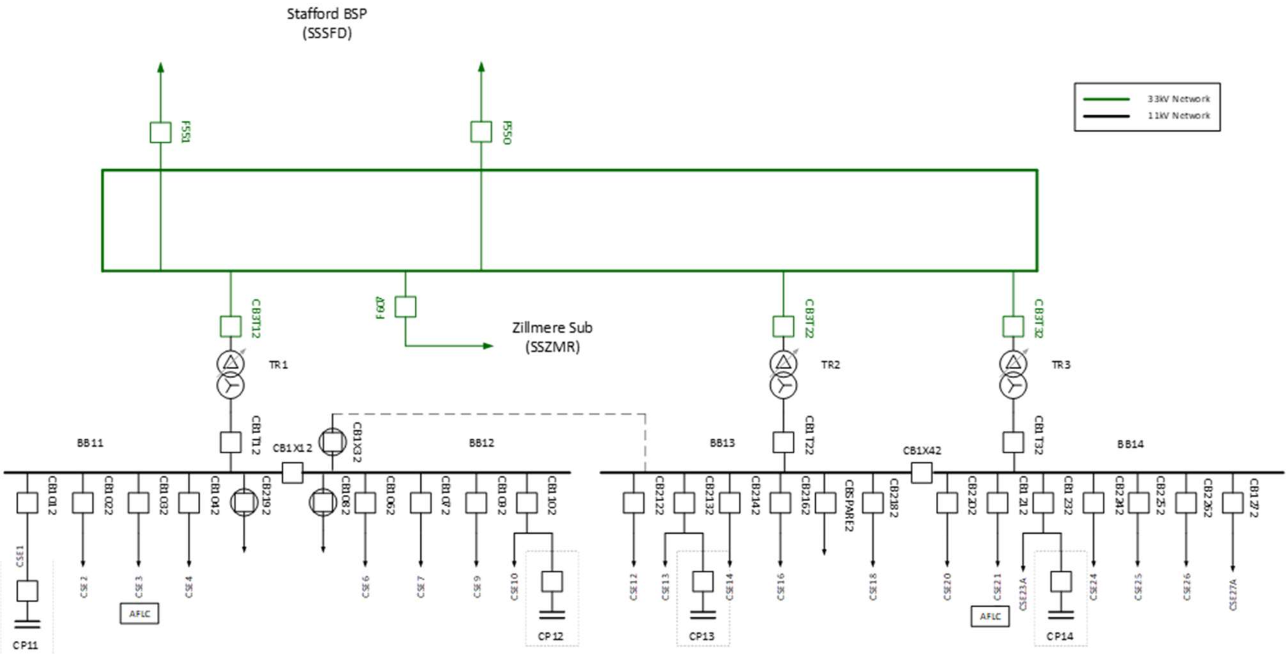


Figure 2: Existing network arrangement (schematic view)

Figure 3: Chermside Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at Chermside Substation comprises a mix of residential and commercial/industrial customers. The load is summer peaking, and the annual peak loads are predominantly driven by commercial load.

2.3.1. Full Annual Load Profile

The full annual load profile for Chermside Substation over the 2023/24 financial year is shown in Figure 4. It can be noted that the peak load occurs during summer.

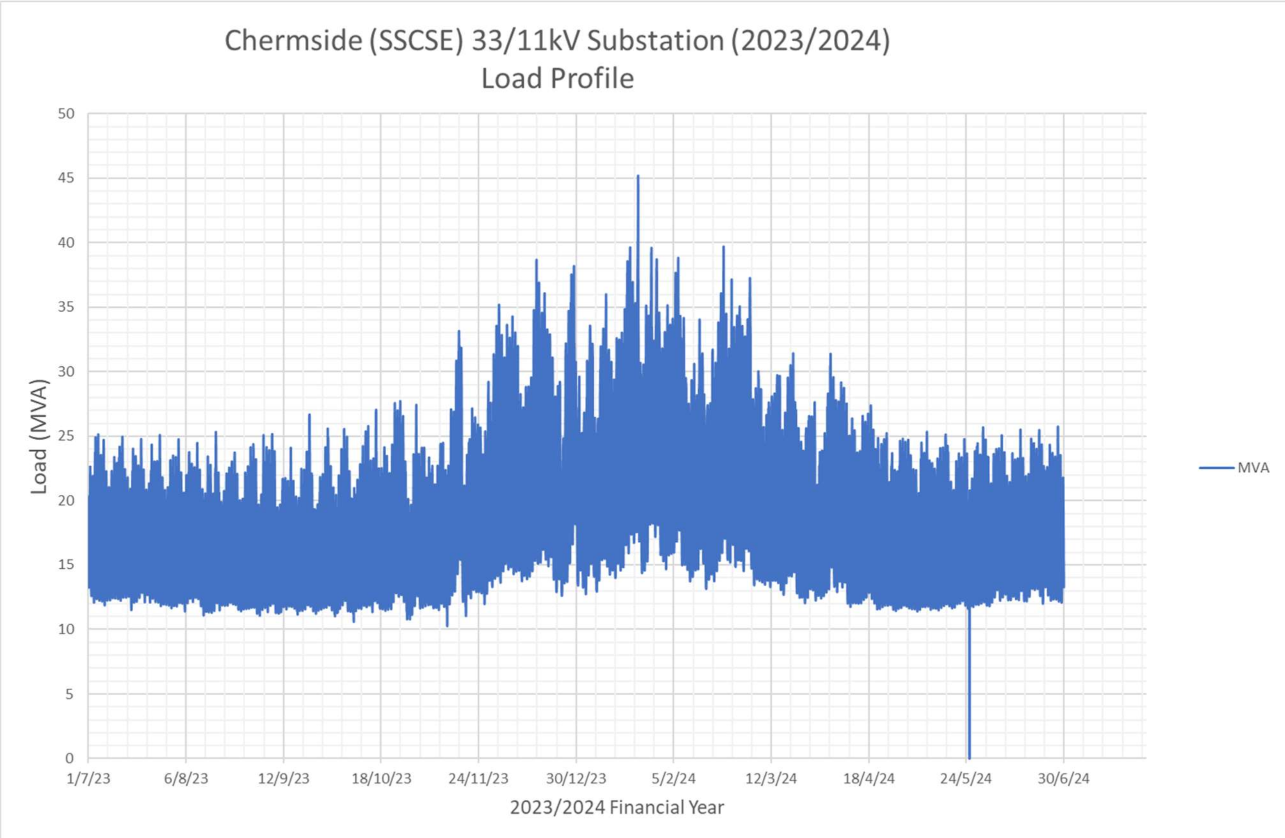


Figure 4: Substation actual annual load profile

2.3.2. Load Duration Curve

The load duration curve for Chermside Substation over the 2023/24 financial year is shown in Figure 5.

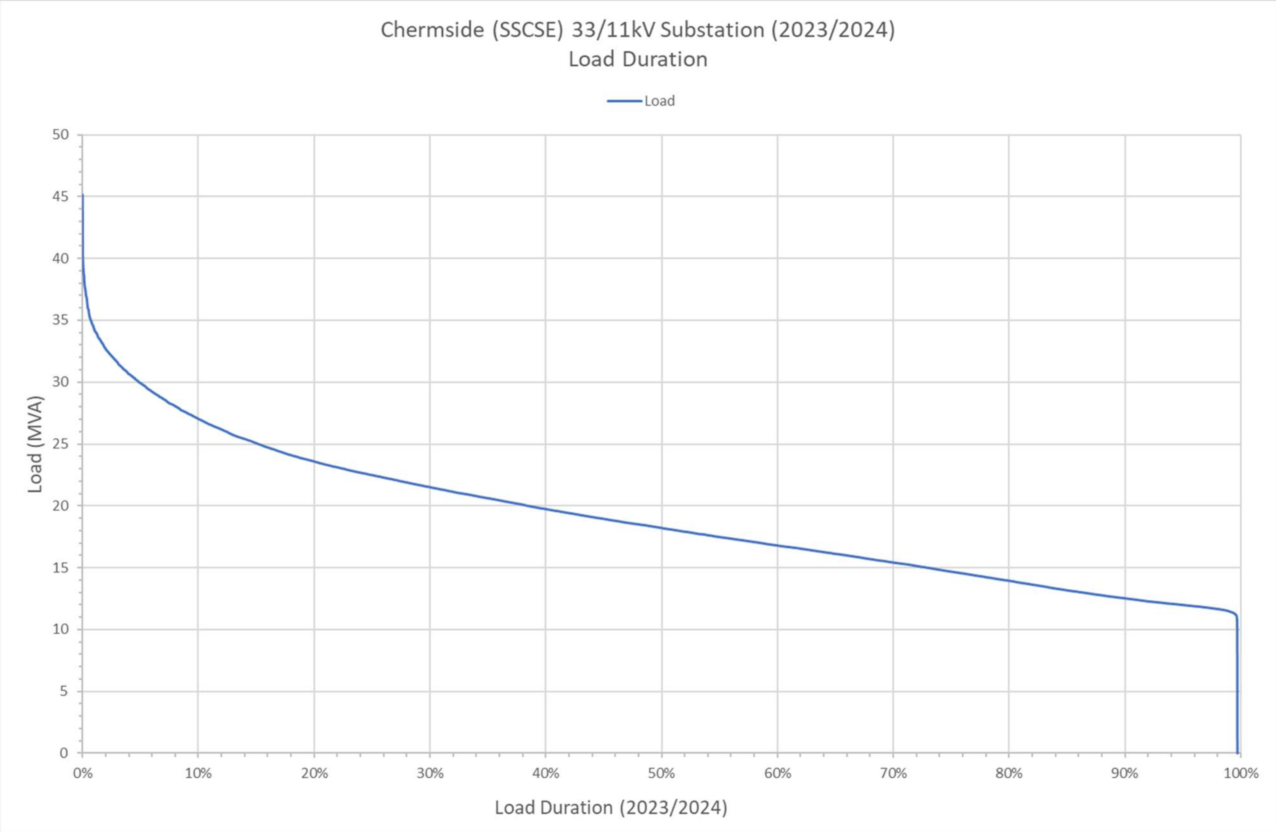


Figure 5: Substation load duration curve

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 Chermside Substation are historically experienced in the late afternoon.

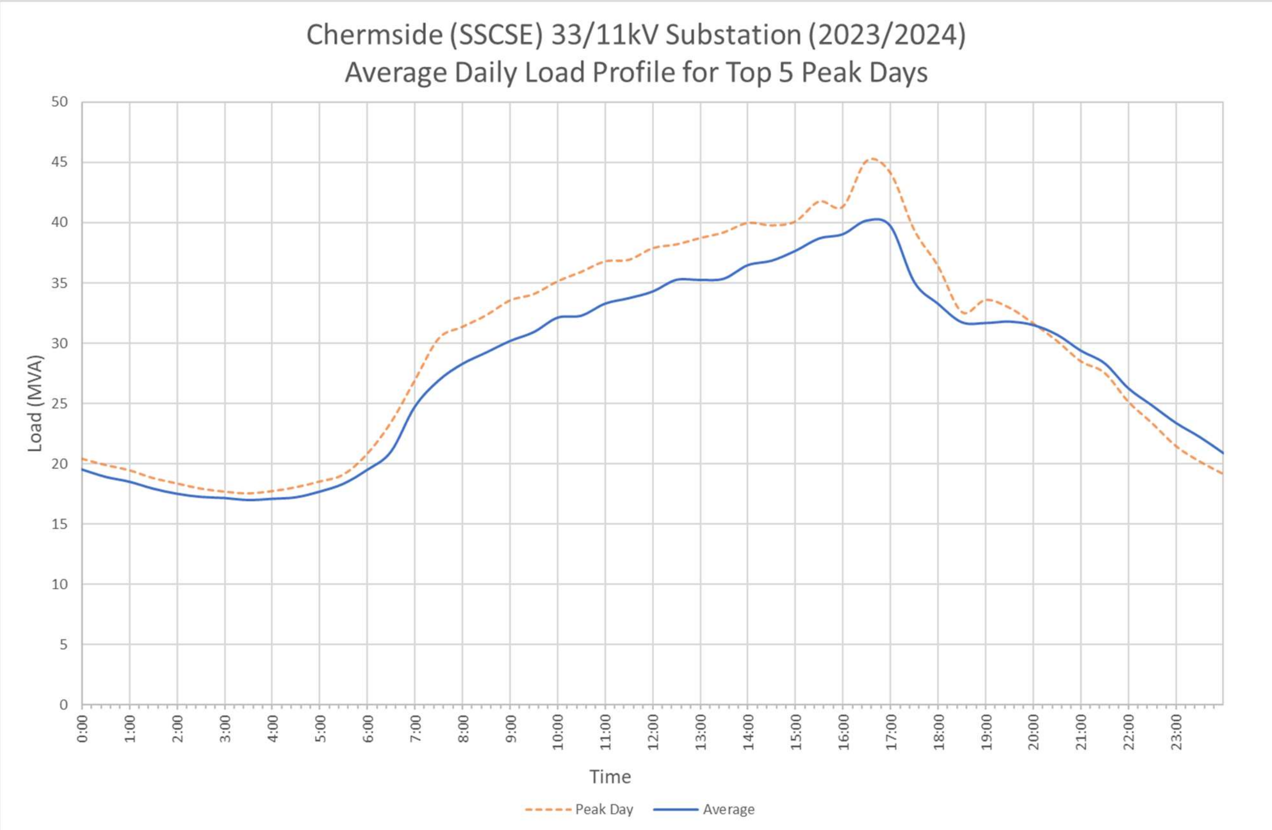


Figure 6: Substation average peak weekday load profile (summer)

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 50% POE forecast load growth in the base case scenario does not exceed the N-1 rating and the 10% POE forecast load growth in the base case scenario does not exceed the NCC rating. 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.

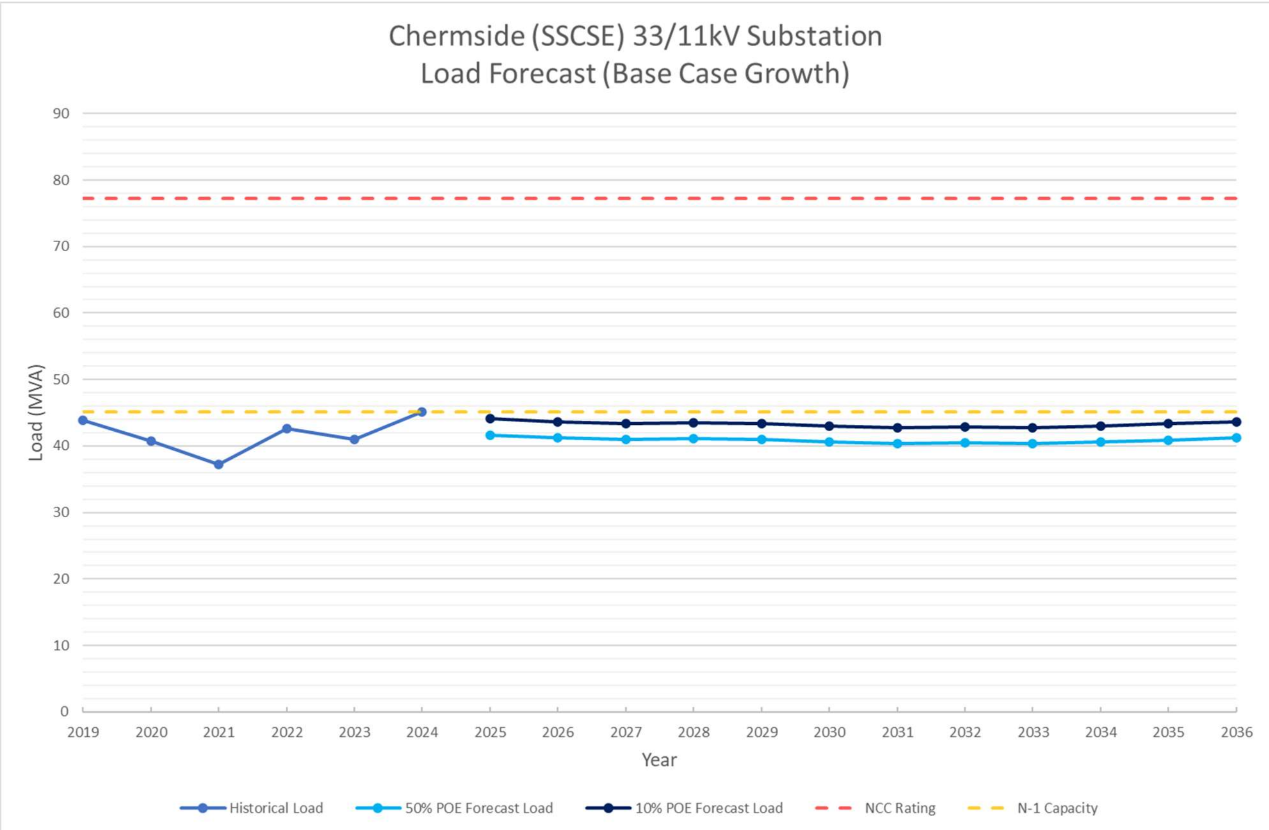


Figure 7: Substation base case load forecast

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 increase over the next 10 years.

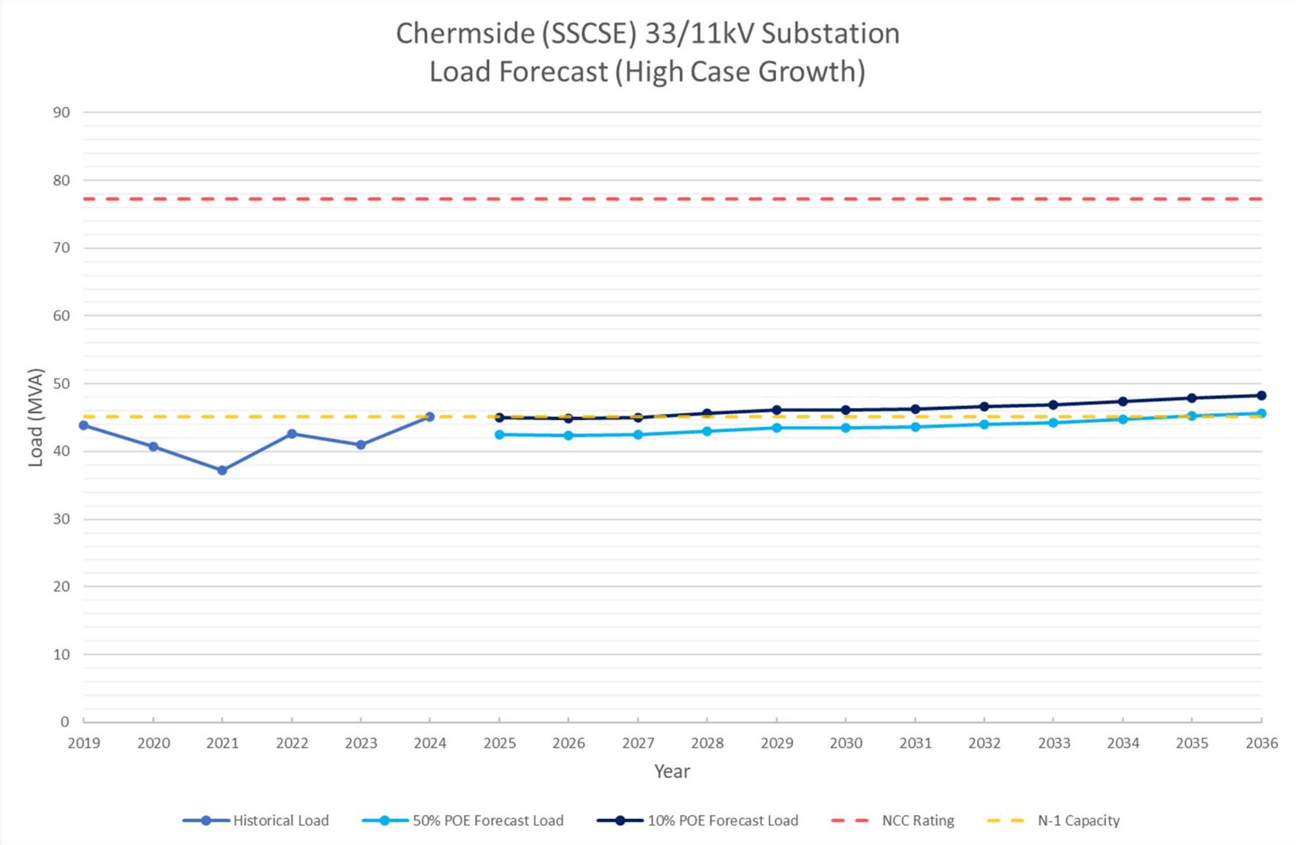


Figure 8: Substation high growth load forecast

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 decrease over the next 10 years.

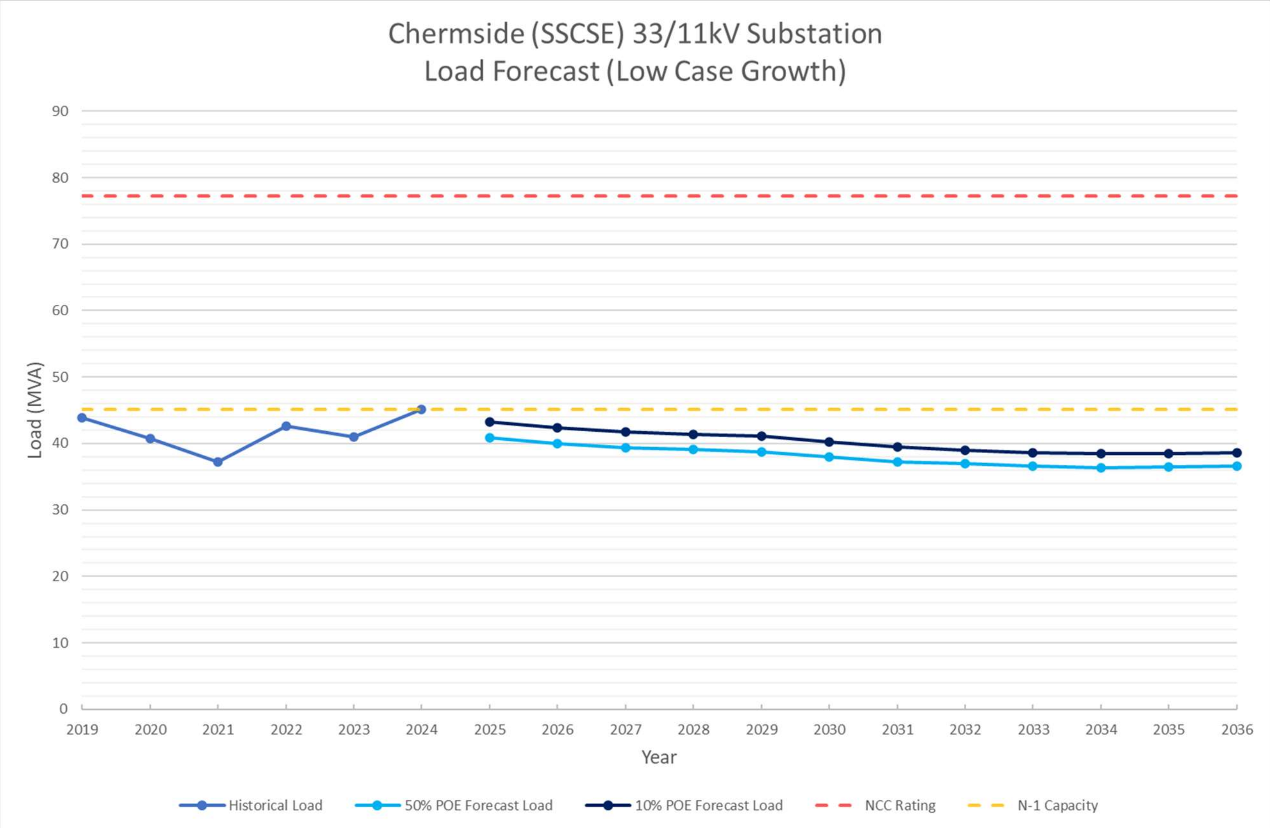


Figure 9: Substation low growth load forecast

3. IDENTIFIED NEED

3.1. Description of the Identified Need

3.1.1. Reliability and Safety

A recent condition assessment has highlighted that a number of critical assets at SSCSE are at end of life and are in poor condition. The condition of these assets presents a considerable safety, environmental and reliability risk. These assets include:

- 11kV switchgears on bus BB11 and bus BB12
- 33/11kV transformer TR1
- 33kV circuit breakers CB3T12, CB5512 and CB5502

Deterioration of these primary and secondary system assets poses safety risks to staff working within the switchyard. It also poses a safety risk the general public, though the increased likelihood of protection relays mal-operation and failure of the circuit breakers. There is also a considerable risk of environmental harm due to tank rupture and oil spill from the circuit breakers, which would require clean up and rectification.

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 Chermside Substation.

Where Energex identifies an imminent asset safety risk, immediate temporary measures are put in place to ensure safety of staff and public until permanent remediation can be performed.

Energex has identified a need to invest in the network to continue to meet safety standards and reliability service standards as required under applicable regulatory instruments,

- Electrical Safety Act 2002 (Qld) – Under Section 29 and 30, Energex has a duty of care to ensure that its works are electrically safe and are operated in a way that is electrically safe. This duty also extends to ensuring the electrical safety of all persons and property likely to be affected by the electrical work.

- Energex's Distribution Authority issued under the Electricity Act 1994 – Under its Distribution Authority, the distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services.

Without such investment, Energex may, in the event of failure of the above identified critical assets, be in breach of regulatory obligations. Therefore, Energex considers that reliability and safety corrective action at SSCSE is necessary.

3.2. Quantification of the Identified Need

3.2.1. Aged and Poor Condition Assets

A recent condition assessment indicates that:

- 33/11kV transformer TR1 is fitted with problematic tap changers. The transformer is showing advance level of insulation degradation and has consistent oil leaks that cannot be permanently fixed, which obscures its true condition and increases the risk of potential catastrophic failure.
- 11kV switchgear on bus BB11 and BB22 are all deemed to reach their retirement age and require replacement.
- Protection relays are deemed to reach their retirement age and require replacement.
- 33kV circuit breakers are due for replacement in 2036. However, protection could not be upgraded to current standards without the modification or replacement of the circuit breakers. Replacing current transformers in the circuit breakers has proved to be impractical in the past. Early replacement is therefore required to eliminate the hazards of oil circuit breaker and porcelain bushings.

3.2.2. Reliability

Currently, the aged assets present a risk to the reliability of supply at SSCSE. Due to the existing condition and configuration of the substation, the following reliability risk scenarios are identified:

- 11kV feeder circuit breaker failure on bus BB11 – a failure of any of the feeder circuit breaker would result in a loss of half of the bus Bus11 load; however, it was assumed that 5.7MVA of load could be supplied by manual transfer within 3 hours.
- 11kV feeder circuit breaker failure on bus BB12 – a failure of any of the feeder circuit breaker would result in a loss of half of the bus BB12 load; however, it was assumed that 1.7MVA of load could be supplied by manual transfer within 3 hours.
- 11kV bus section breaker failure – a failure of the bus section circuit breaker would result in a loss of the bus 1 load; however, it was assumed that 5.7MVA of load could be supplied by manual transfer within 3 hours.
- 33kV TR1 circuit breaker – a failure of the 33kV circuit breaker would result in a loss of the 33kV bus initially; however, it was assumed that isolator can be manually switch out to isolate CB3T12 and restore F551, F550, TR2 and TR3, and 3.1MVA of load could be supplied by manual transfer within 3 hours as well.
- 33kV F551 circuit breaker – a failure of the 33kV circuit breaker would result in a loss of the 33kV bus initially; however, it was assumed that isolator can be manually switch out to isolate CB5512 and restore F550, TR1, TR2 and TR3, and 3.1MVA of load could be supplied by manual transfer within 3 hours as well.
- 33kV F550 circuit breaker – a failure of the 33kV circuit breaker would result in a loss of the 33kV bus initially; however, it was assumed that isolator can be manually switch out to

isolate CB5502 and restore F551, TR1, TR2 and TR3, and 3.1MVA of load could be supplied by manual transfer within 3 hours as well.

- 33/11kV TR1 – It was assumed that TR2 and TR3 is in service to supply the substation load after a failure of TR1, and 3.1MVA of load could be supplied by manual transfer within 3 hours as well.

3.2.3. Risk Quantification Benefit Summary

Risk quantification analysis has been completed on the existing network, which includes the value of customer reliability and cost of emergency replacement. Figure 10 shows the risk of continuing the use of the existing ageing assets.

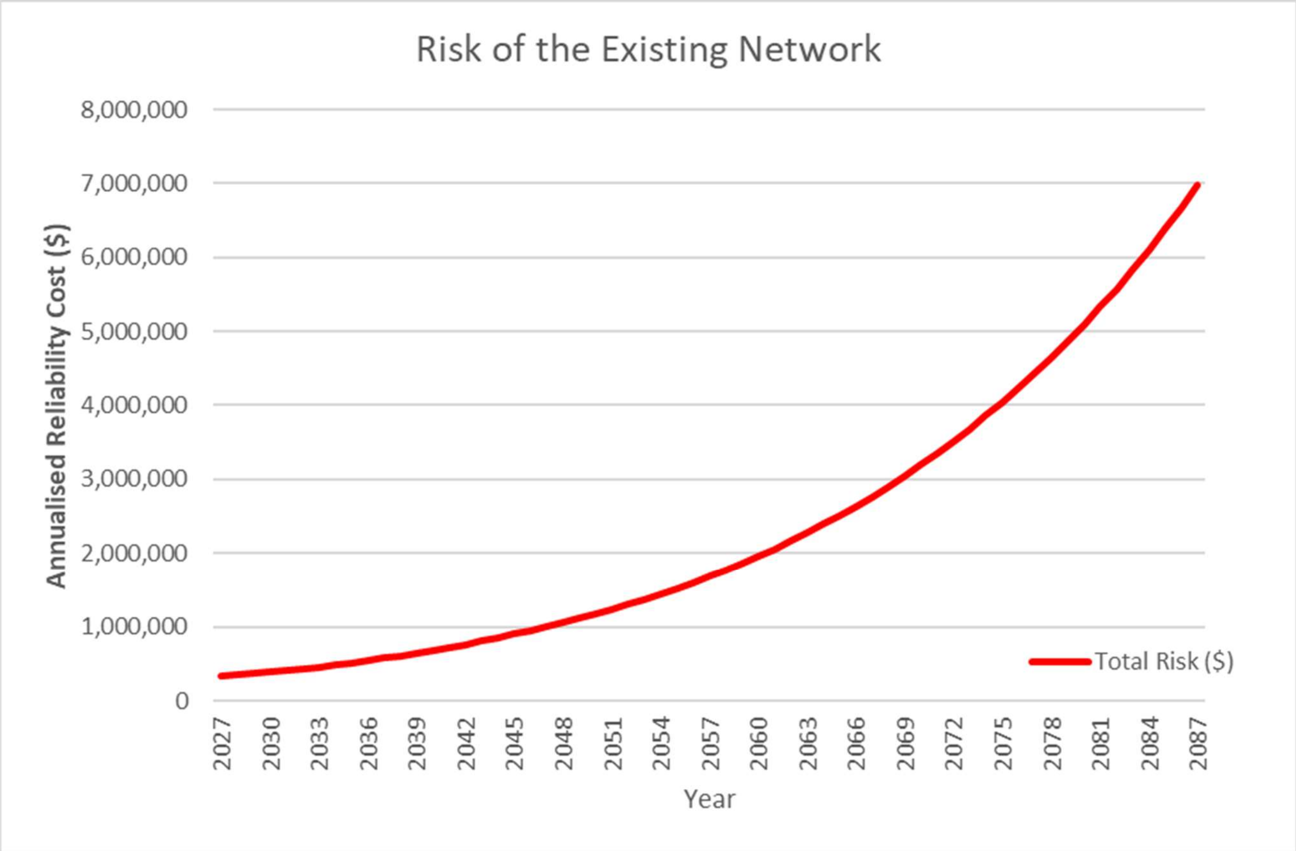


Figure 10: Annualised Reliability Cost

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 Chermside 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 one credible network options that will address the identified need and is commercially and technically feasible and can be implemented in sufficient time to meet the identified need.

4.1.1. Option 1: Replace 11kV circuit breakers, TR1 and 33kV circuit breakers.

This option involves the following works:

- De-commission and recover existing 33kV circuit breakers CB3T12, CB5502, CB5512, and replace with new circuit breakers.
- De-commission and recover existing 11kV switchgears on bus BB11 and bus BB12. Construct a new 11kV switchgear building and install current contract switchgears.
- Recover and scrap the existing relays on CB2122, CB2142, CB2162, CBSPARE22, CB2182, CB1212, CB2242, CB2252 and CB1272. Install current contract equivalents in their place.
- Decommission and recover existing 33/11kV TR1 and replace with a new transformer.
- Install a 33kV bus section circuit breaker between AB3X14 and AB3X15.
- Install a 33kV bus section circuit breaker between AB3X18 and AB3X19.

Due to the scope of works being entirely contained within the existing substation site at Chermside, as well as the expected reliability and safety benefits of this option to the local community, there are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline. While Energex does not anticipate any community stakeholder concerns, should any be identified, these would be addressed as part of the Energex Community Engagement Framework which is integrated into the project workflow.

The estimated direct cost of this option is $11.6 million inclusive of the contingency allowance. Annual operating and maintenance costs are estimated to be $4000 as a result of this option and the contingency allowance is estimated to be $574,439. The estimated project delivery timeframe has design commencing in April 2025 and construction completed by July 2028.

A schematic diagram of the proposed network arrangement for Option 1 is shown in Figure 11.

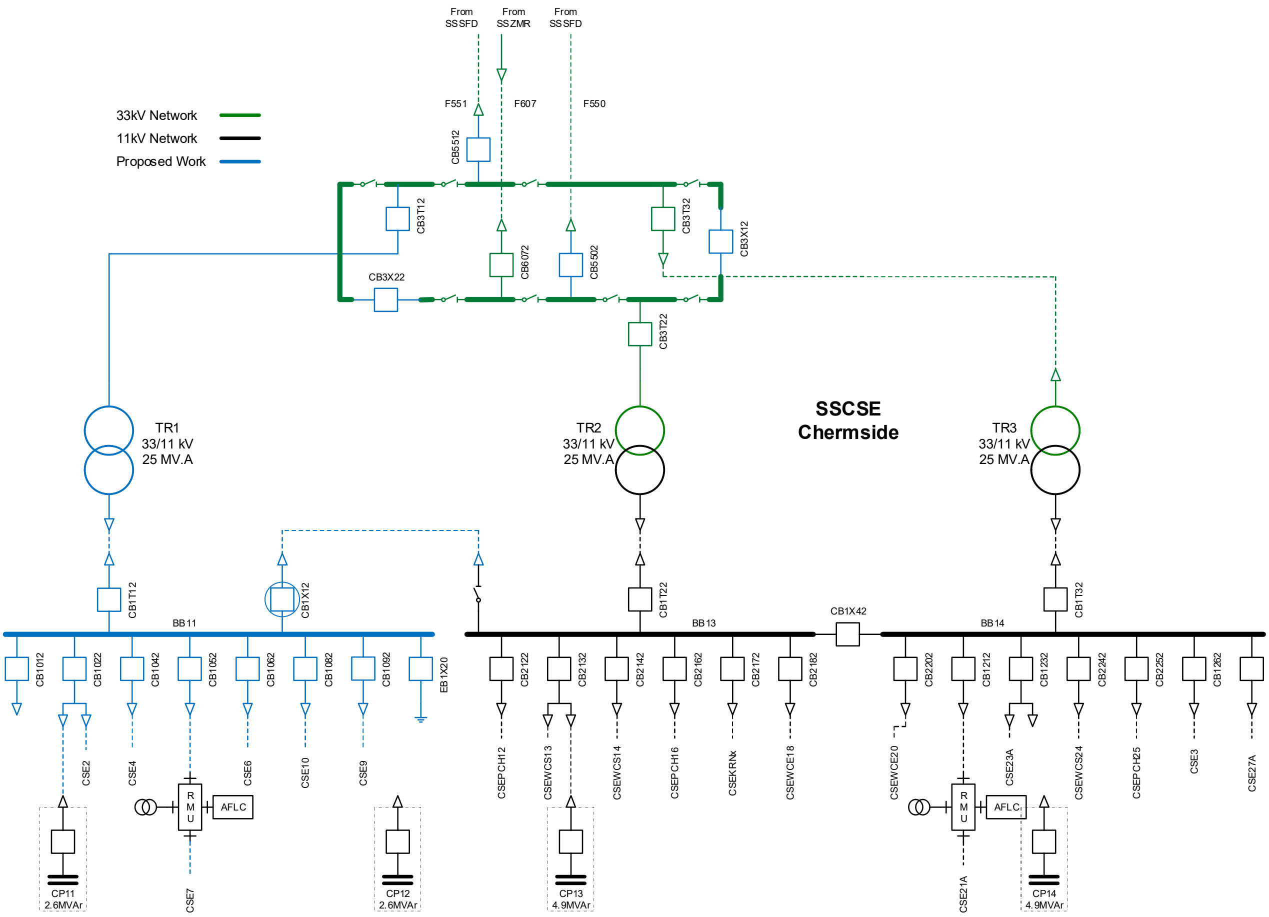


Figure 11: Option 1 proposed network arrangement (schematic view)

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 Chermside region 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 (NNA) 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 Chermside customer base and considered a number of demand management technologies. However, as the identified need is for reliability corrective action it has been determined that demand management options would not be viable propositions for the following reasons.

4.2.3. Network Load Control

The residential customers and commercial load appear to drive the daily peak demand which generally occurs between 2:00pm and 5:00pm.

There are 3961 customers on tariff T31 and T33 hot water load control (LC). An estimated demand reduction value of 1466kVA[1] is available.

The Tariff 33 and 31 hot water LC channels are dynamic (that is, it responds to exceedance settings not on a timetable). The current control strategy only calls LC under the following condition:

- Overload on 33/11kV TR1 with either TR2 or TR3 has an outage
- Overload on 33/11kV TR2 with either TR1 or TR3 has an outage
- Overload on 33/11kV TR3 with either TR1 or TR2 has an outage

[1] Hot water diversified demand saving estimated at 0.6kVA per system

Tariff 33 air-conditioning channels are under manual control of the operational control centre and are used as required. Therefore, network load control would not sufficiently address the identified need.

4.2.4. 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 primary driver for investment in this instance is asset safety and performance. 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 will not address the identified network requirement.

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 2113 customers have solar photo voltaic (PV) systems for a connected inverter capacity of 13,344kVA.

The daily peak demand is driven by residential customer demand and the peak generally occurs between 2:00pm and 5:00pm. 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 a 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.

4.2.5. SAPS and Non-Network Solution Summary

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

4.3. Preferred Network Option

Energex's preferred internal network option is Option 1, to replace 11kV circuit breakers, TR1 and 33kV circuit breakers.

Upon completion of these works, the asset safety and reliability risks at Chermside Substation will be addressed. 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 direct cost of this option is $11.6 million inclusive of the contingency allowance. Annual operating and maintenance costs are estimated to be $4000 as a result of this option and the contingency allowance is estimated to be $574,439 to cater for the risks of:

- Uncertainties regarding staging an additional SACS build
- Due to subjective nature of security classifications and variety of acceptable control measures, requirements of the security system cannot be finalised during the design phase
- Time and cost of civil design and supervision cannot be finalised until layout and staging is underway during the design phase
- Implementation of a different scheme or use of different relays may be required due to incomplete specifications for some current transformers in the switchgear

A breakdown of the cost estimate is provided in Table 1.

Expenditure Category	Cost estimate
Labour	$5,447,482
Materials	$2,151,823
Contractors	$4,031,241
Total direct cost	**$11,630,546**

Table 1: Base case NPV ranking table

The estimated project delivery timeframe has design commencing in April 2025 and construction completed by July 2028.

5. 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.

5.1. 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

5.1.1. 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.

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 Chermside supply area.

5.2. 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
- Option value
- Changes in Greenhouse gas emissions
- Costs Associated with Social Licence Activities
- Other Classes of Market Benefit

5.2.1. 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 Chermside area. Therefore, market benefits associated with changes in voluntary load curtailment have not been considered.

5.2.2. 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.

5.2.3. Differences in Timing of Expenditure

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

5.2.4. 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 Chermside area.

5.2.5. 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.

5.2.6. 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[2].

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.

5.2.7. Changes in Greenhouse Gas Emissions

Energex does not anticipate that the credible option included in the RIT-D assessment, which involves replacing network assets which maintain the same network configuration, will lead to any changes in greenhouse gas emissions.

5.2.8. Costs Associated with Social Licence Activities

Energex does not anticipate that the credible option included in the RIT-D assessment will involve costs associated with licence activities.

5.2.9. Other Class of Market Benefit

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

[2] 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

6. DETAILED ECONOMIC ASSESSMENT

6.1. Methodology

The Regulatory Investment Test for Distribution 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 National Electricity Market.

Accordingly, a base case Net Present Value (NPV) comparison of the alternative development options 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.

6.2. 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. The interest on borrowings is included in the Total Project Cost for which approval is being sought as it represents a legitimate cost of network augmentation.

6.3. Cost Estimation Methodology

Energex uses a combination of comparative and standard cost estimating methodologies, underpinned by a bottom-up approach as the basis for the estimation process.

Comparative cost estimation is based on experiences of the past and makes use of the information contained in previous proven project designs that closely match the attribute of a new project.

Standard cost estimation forms the basis of typical larger, lower volume high complexity type network projects incorporating the experience and knowledge of agreed engineered standard ways of construction of network components.

Underpinning both the comparative and standard cost estimation methodologies is a bottom-up approach that consolidates associated labour, materials, equipment, contract costs with the defined scope of works.

6.4. Quantification of Benefit for Option 1

Risk quantification analysis has been completed for option 1 which includes the value of customer reliability and cost of emergency replacement. Figure 12 shows the benefits of Option 1 in comparison to the counter-factual, which in this case is continuing the use of the existing circuit breakers and maintenance and operation. The benefit of this option is greater than $409,000 by 2031.

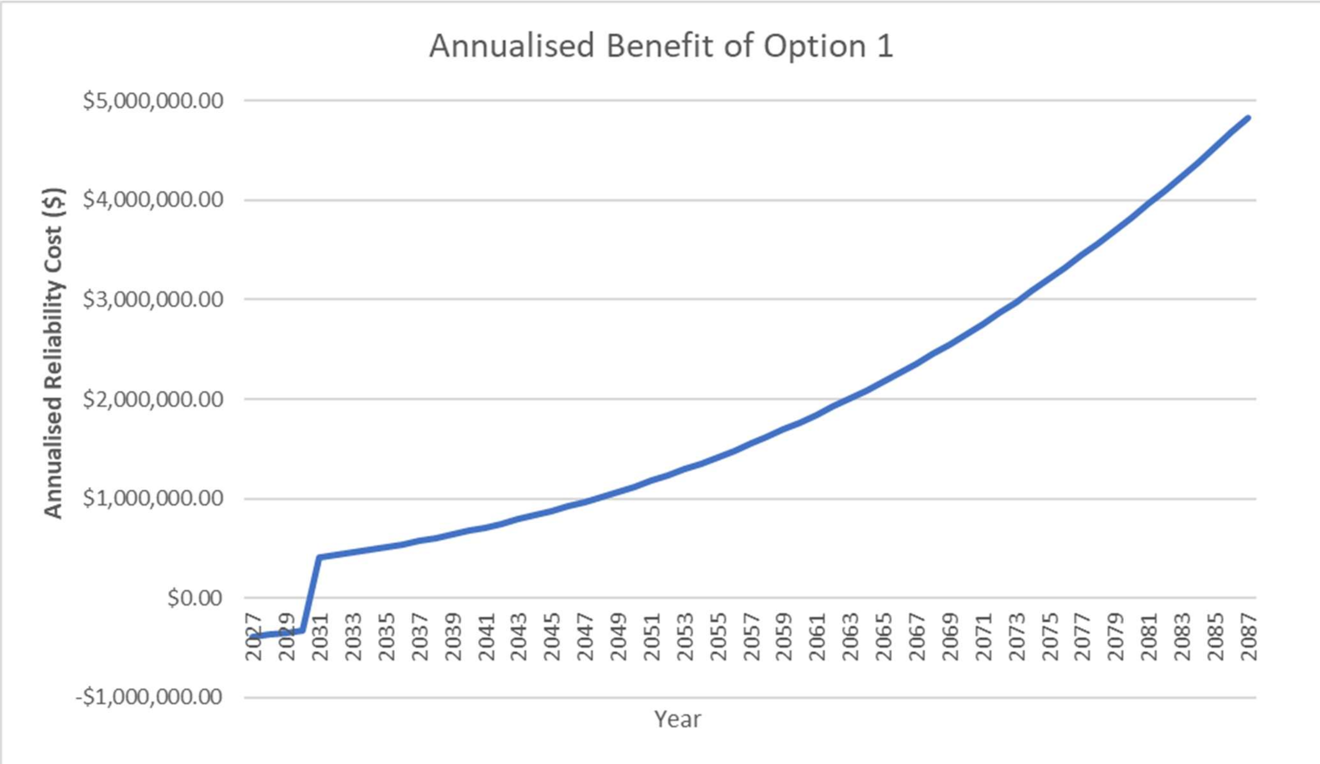


Figure 12: Annualised Benefits of Option 1 compared with Counter Factual

6.5. Net Present Value (NPV) Results

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

Op	Option Name	Rank	Initial Cost	Net Present Value ($ real)	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
1	Replace 11kV circuit breakers, TR1 and 33kV circuit breakers	1	$11,630,546	$21,935,000	$32,657,000	-$10,612,000	-$109,000

Table 2: Base case NPV ranking table

7. CONCLUSION

The Final Project Assessment Report (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 proposed preferred option to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements, as necessary.

7.1. Preferred Option

Energex's preferred option is Option 1, to replace 11kV circuit breakers, TR1 and 33kV circuit breakers at Chermside Substation.

Upon completion of these works, the asset safety and reliability risks at Chermside Substation will be addressed. 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 direct cost of this option is $11.6 million inclusive of the contingency allowance. Annual operating and maintenance costs are estimated to be $4000 as a result of this option and the contingency allowance is estimated to be $574,439. The estimated project delivery timeframe has design commencing in April 2025 and construction completed by July 2028.

7.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

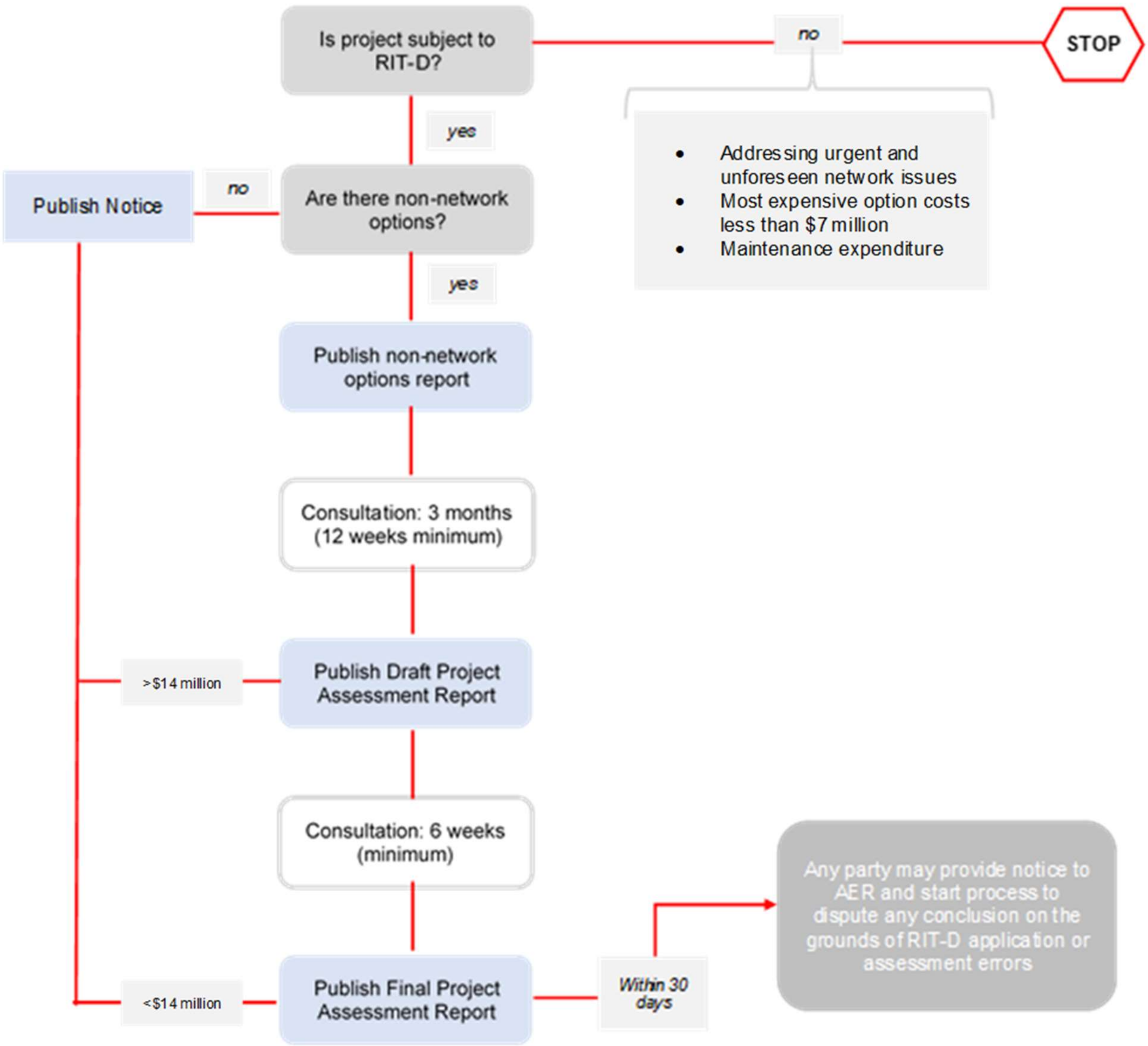
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

8. 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 Notice of Screening for Options Report	1.1
(4) a description of each credible option assessed including cost breakdown and contingency allowance.	4
(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	5
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	6
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	5
(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	5.2
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	6.5
(10) the identification of the proposed preferred option	7.1
(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	7.1 & 7.2
(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
(13) the methodology applied in deriving the cost estimates.	6.3

APPENDIX A – THE RIT-D PROCESS



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