Regulatory Investment Test for Distribution (RIT-D)

Caloundra Zone Substation Limitation

Draft Project Assessment Report

13 August 2021

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

Caloundra Zone Substation (SSCLD) provides electricity supply to approximately 22,000 predominantly residential customers in the Aroona, Caloundra, Currimundi, Meridan Plains, Pelican Waters and Shelly Beach areas. SSCLD is supplied from the Powerlink Palmwoods injection point via a 132kV ring network, which also supplies Mooloolaba zone substation (SSMLB), Currimundi zone substation (SSCMD), Birtinya zone substation (SSBTY), Kawana zone substation (SSKWA), Alexandra Headlands zone substation (SSAHD) and West Maroochydore zone substation (SSWMD). There is also a 33kV network that is supplied by Beerwah bulk supply substation (SSBWH) that provides supply to Woodford zone substation (SSWFD) and Landsborough zone substation (SSLBH). With new developments in the Bells Creek area, loads are forecast to increase significantly causing network limitations in the area.

Draft Project Assessment Report

The identified need for this Draft Project Assessment Report (DPAR) is that Energex will experience three upcoming network limitations:

- **Immediate 11kV feeder limitation**: Forecast exceedance of the Target Maximum Utilisation (TMU) on 11kV feeder CLD11 in 2021
- **Future 11kV feeder limitations**: feeders CLD1A, CLD18A and CLD29A from 2023 onwards. It should be noted that although there is technically an exceedance of the TMU for CLD11 in 2021, this is an extremely small load at risk of 0.26MVA. As such, Energex are not proposing to provide a solution, either network or non-network, to this limitation until 2022.

Year	CLD1A Load (MVA)	CLD11 Load (MVA)	CLD18A Load (MVA)	CLD29A Load (MVA)
2020	0.00	0.00	0.00	0.00
2021	0.00	0.26	0.00	0.00
2022	0.00	0.85	0.00	0.00
2023	0.00	1.15	0.00	0.41
2024	0.00	1.31	0.00	1.31
2025	0.00	1.57	0.00	3.31
2026	0.03	1.82	0.00	5.41
2027	0.21	2.07	0.50	7.51
2028	0.38	2.32	1.45	9.81
2029	0.56	2.57	2.40	12.01
2030	0.74	2.82	3.36	14.51

Table 1: Forecast load at risk

- **Future substation limitation**: Forecast breach of its Safety Net obligation as outlined in its Distribution Authority at SSCLD in the period between 2027 and 2030.

As part of its operational strategy following a contingency, Energex will deploy 4MVA of generation using its fleet of mobile generators. In addition to the requirements above, Energex would be interested in any network support solutions that provide a cost-effective alternative to this requirement. Submissions to this DPAR should clearly separate their proposal for this extra support opportunity from their proposed solution to the identified need.

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

In order to eliminate the load at risk and satisfy the 11kV feeder limitations and Safety Net obligations, Energex has identified nine network options to address the limitations identified, as below:

- Option 1: Supply New Demand with 11kV Feeders from SSCLD
- Option 2: Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment
- Option 3: Supply New Demand with 11kV Feeders from SSCLD and Establish 132kV Feeders, then Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment
- Option 4: Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek North Establishment
- Option 5: Supply New Demand with 33kV Feeders from Meridan Plains Establishment to Bell's Creek Central Establishment
- Option 6: Supply New Demand with 33kV Feeders from Meridan Plains (132/33/11kV) Establishment to Bell's Creek Central Establishment
- Option 7: Supply New Demand with 33kV Feeders from Meridan Plains (132/33kV, 33/11kV) Establishment to Bell's Creek Central Establishment
- Option 8: Supply New Demand with 132kV Feeders (Tee off at Mark Rd East) to Bell's Creek Central Establishment
- Option 9: Supply New Demand with 132kV Feeders from Caloundra Substation to Bell's Creek Central Establishment

Energex published a Non-Network Options Report for the above described network constraint on 16 November 2020 and one submission was received.

One potentially feasible option has been investigated:

- Option 10**:** Contract a 24MW Battery Energy Storage Solution (BESS)

This DPAR, where Energex provides both technical and economic information about possible solutions, has been prepared in accordance with the requirements of clause 5.17.4(i) of the NER.

Energex's preferred solution to address the identified need is Option 2 - Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment. The DPAR seeks information from interested parties about possible alternate solutions to address the need for investment.

Submissions in writing are due on the **8 October 2021** by 4pm and must be lodged to demandmanagement@energex.com.au

For further information and inquiries please contact:

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CONTENTS

1. INTRODUCTION

This DPAR has been prepared by Energex in accordance with the requirements of clause 5.17.4(i) of the NER.

This report represents the second 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 Caloundra 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 Caloundra 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.
- 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.
- Is an invitation to registered participants and interested parties to make submissions.

1.2. Contact Details

Submissions in writing are due by 4pm on **8 October 2021** and should be lodged to demandmanagement@energex.com.au.

For further information and inquiries please contact:

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2. BACKGROUND

2.1. Geographic Region

Caloundra Zone Substation (SSCLD) provides electricity supply to approximately 22,000 predominantly residential customers in the Aroona, Caloundra, Currimundi, Meridan Plains, Pelican Waters and Shelly Beach areas. SSCLD is supplied from the Powerlink Palmwoods injection point via a 132kV ring network, which also supplies Mooloolaba zone substation (SSMLB), Currimundi zone substation (SSCMD), Birtinya zone substation (SSBTY), Kawana zone substation (SSKWA), Alexandra Headlands zone substation (SSAHD) and West Maroochydore zone substation (SSWMD). There is also a 33kV network that is supplied by Beerwah bulk supply substation (SSBWH) that provides supply to Woodford zone substation (SSWFD) and Landsborough zone substation (SSLBH).

The geographical location of Energex's sub-transmission network and substations in the area is shown in Figure 1 and Figure 2.

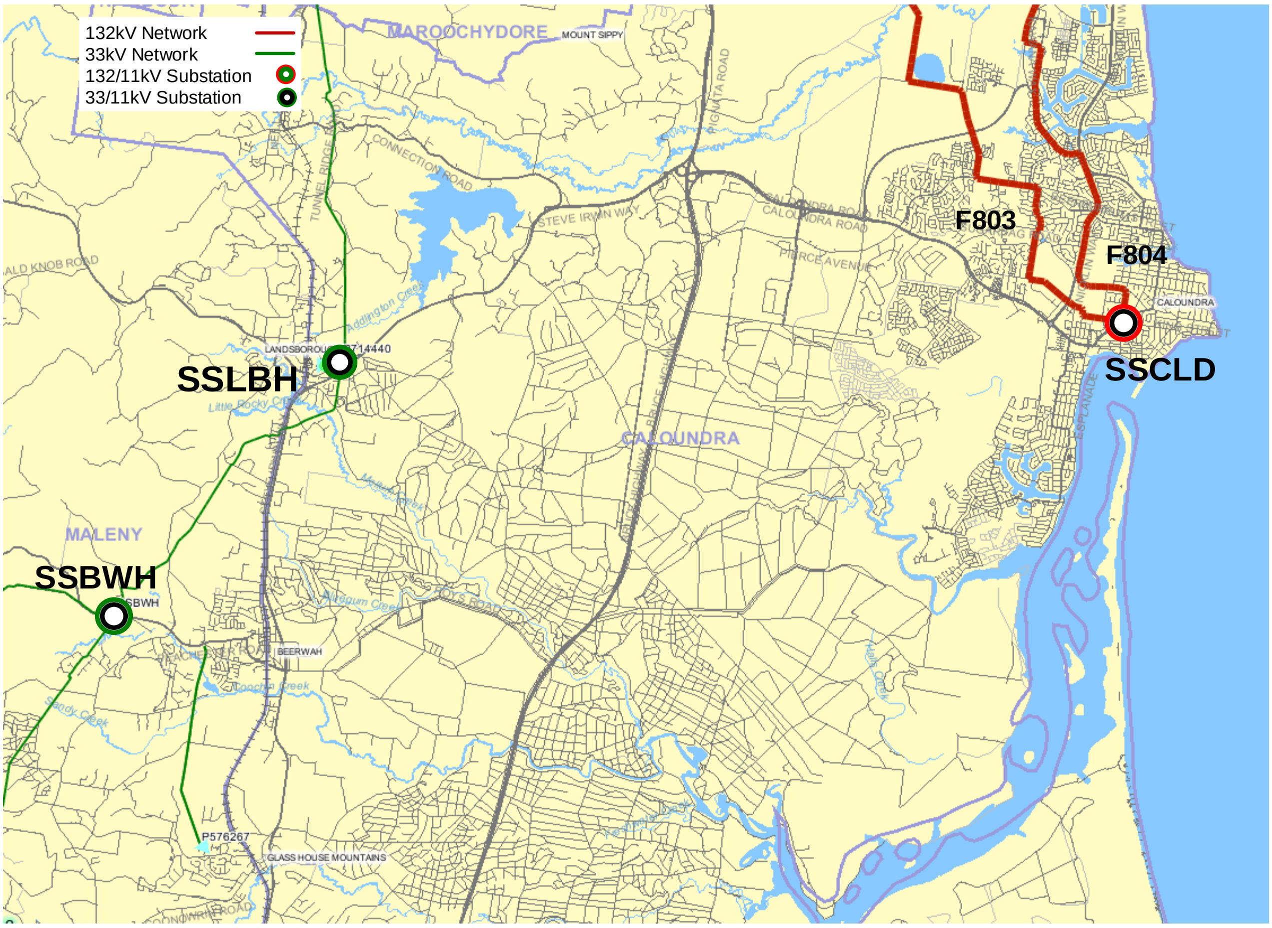


Figure 1: Existing 132/33kV network arrangement (geographic view)

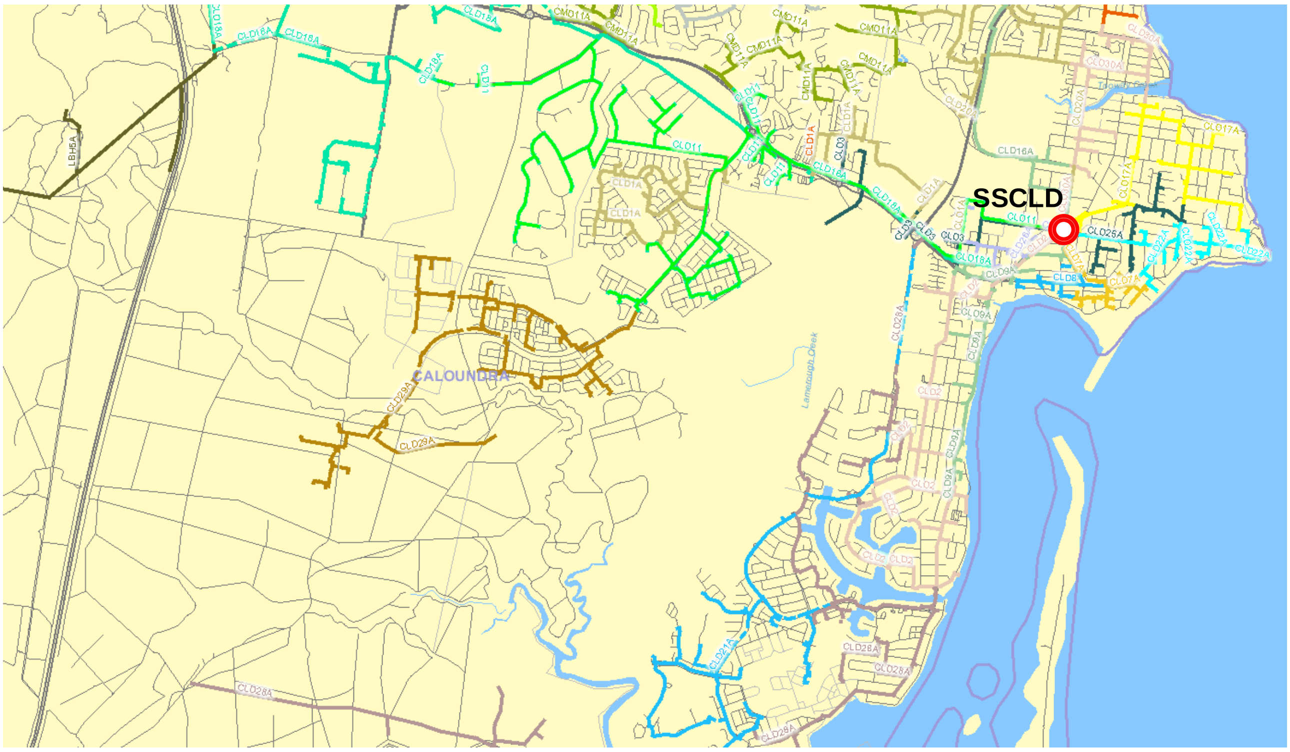


Figure 2: Existing 11kV network arrangement (geographic view)

2.2. Existing Supply System

Caloundra zone substation is supplied via 2 incoming 132kV feeders in a ring network from Mooloolaba zone supply substation and Currimundi zone supply substation under system normal.

Caloundra zone substation has 2 x 60MVA 132/11kV transformers. The substation supplies 20 x 11kV distribution feeders.

A schematic view of the existing sub-transmission network and substation arrangement is shown in Figure 3 and Figure 4.

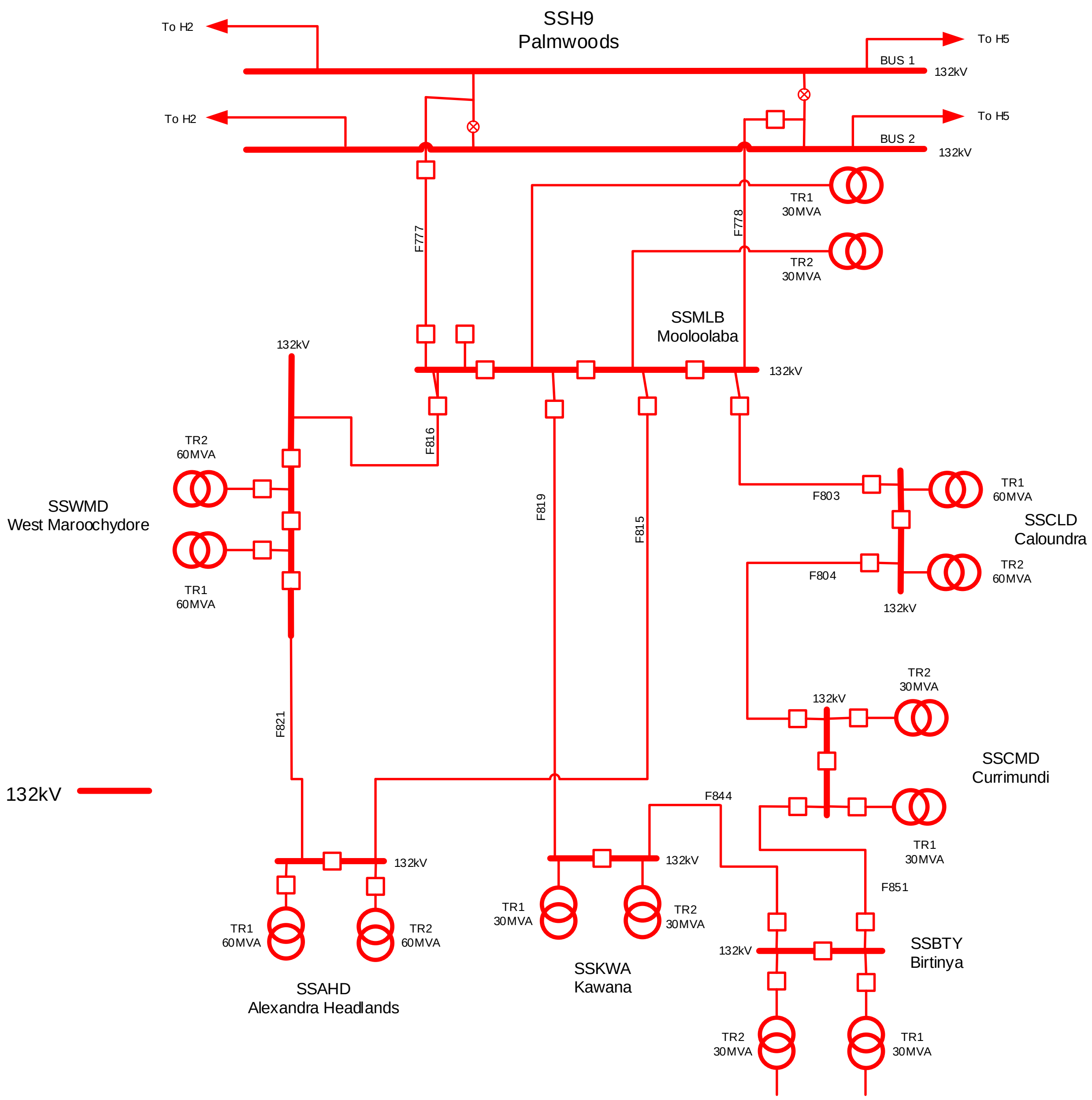


Figure 3: Existing network arrangement (schematic view)

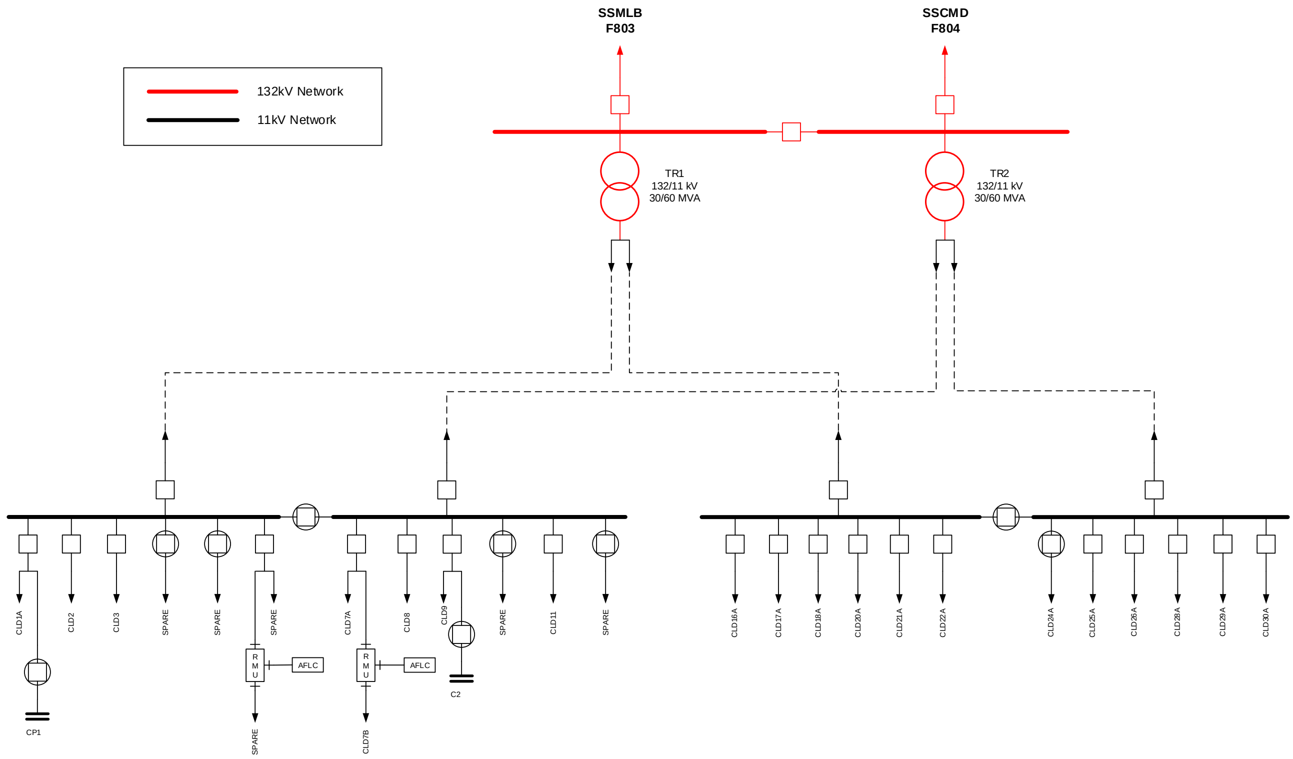


Figure 4: Existing substation arrangement (schematic view)

2.1. Development Overview and Demand Forecast

The Aura development (previously known as Caloundra South) is south-west of SSCLD and is a master-planned community that will have over 20,000 new homes in a 24km^2 site within the next 30 years. The development also contains a significant commercial and light industrial area, forecast to be roughly half the load of the development. Further to this, there is an existing Sunshine Coast Industrial Park directly west of SSCLD which is currently planned for a large expansion.

When fully developed, this industrial park will represent a load of around 15MVA to 20MVA. Figure 5 below shows the development area, with Table 2 showing the ultimate load of the area. As can be seen from Table 2, even under a low load scenario, the ultimate load in the Aura development alone totals at least 47MVA. When this is combined with the projected low load scenario of the Sunshine Coast Industrial Park directly north of Aura the total load in the area is forecast to be at least 62MVA.

For the Energex network, a typical 132/11kV zone substation has a capacity of between 40-70MVA, with the capacity of a two transformer 33/11kV zone substation around 30-40MVA. There are 4 feeders surrounding the Aura development – CLD1A, CLD11, CLD18A and CLD29A (see Figure 2) however, CLD29A is the only dedicated feeder feeding the Aura development. CLD1A and CLD11 both predominately feed the established Bellavista development adjacent to Aura while CLD18A will be the main feeder supplying the future Sunshine Coast Industrial Park.

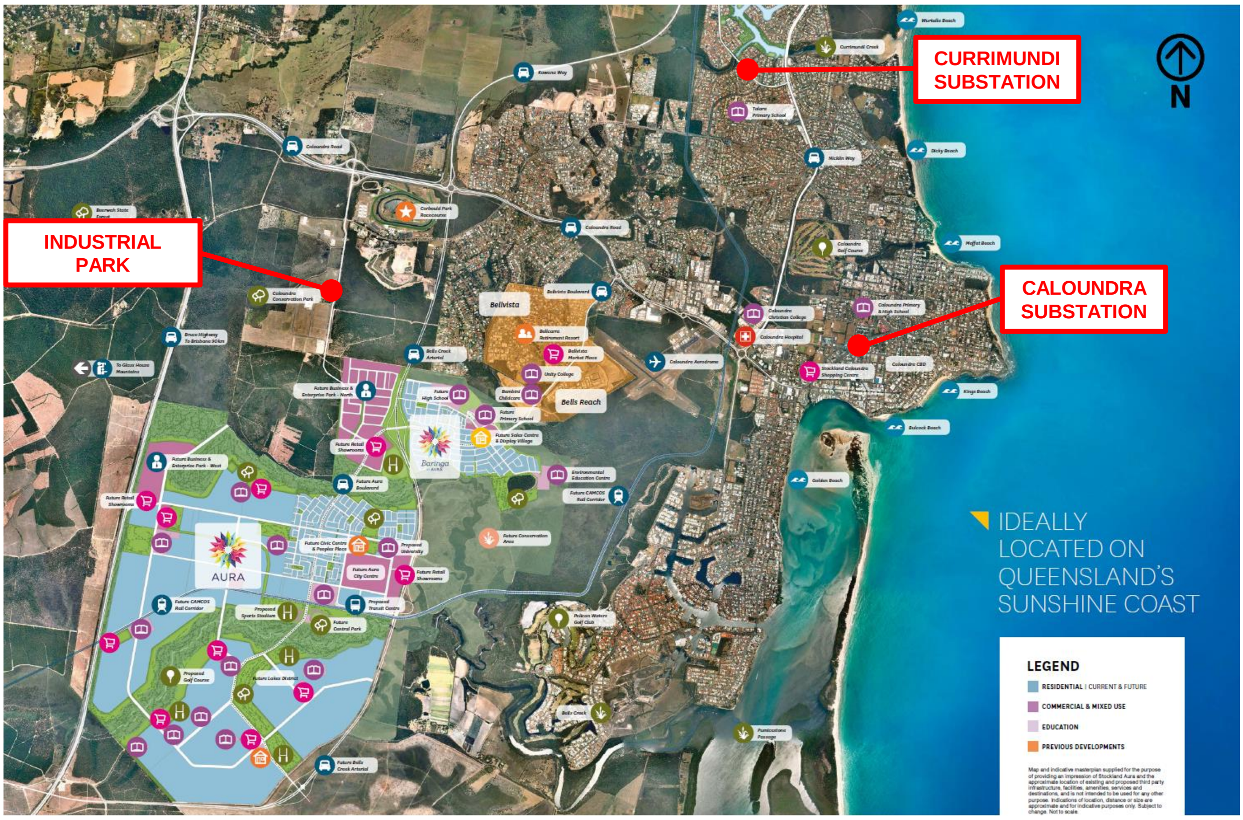


Figure 5: Proposed Aura development area

Load Type	Low Load Scenario (MVA)	Medium Load Scenario (MVA)
Commercial	14.90	18.60
Industrial Light	8.50	10.60
Residential High	0.50	0.60
Residential High B5	1.80	2.40
Residential Medium	6.00	8.00
Residential Undeveloped	15.30	20.40
Total for Aura Development	**47.00**	**60.40**
Sunshine Coast Industrial Park	15.00	20.00
Area Total – South Caloundra	**62.00**	**80.40**

Table 2: Ultimate load for the development

2.2. Load Profiles

The load at Caloundra zone substation comprises a mix of residential and commercial/industrial customers. The load duration curve for feeders CLD1A, CLD11, CLD18A and CLD29A are shown in Figure 6 to Figure 9 below. It should be noted CLD29A is a new feeder established in September 2020 and approximately 2MVA of load was transferred from CLD18A. Due to the new feeder not having historic data, the load duration curve for CLD29A was developed from CLD18A data and utilising the new CLD29A load forecast.

2.2.1. Load Duration Curve

Figure 6 to Figure 9 shows the load duration curves for SSCLD under System Normal (N) and System Abnormal (N-1). These are based on the previous 3 years of data and are scaled to their respective maximum 10% Probability of Exceedance (10PoE) and 50% Probability of Exceedance (50PoE) forecasts.

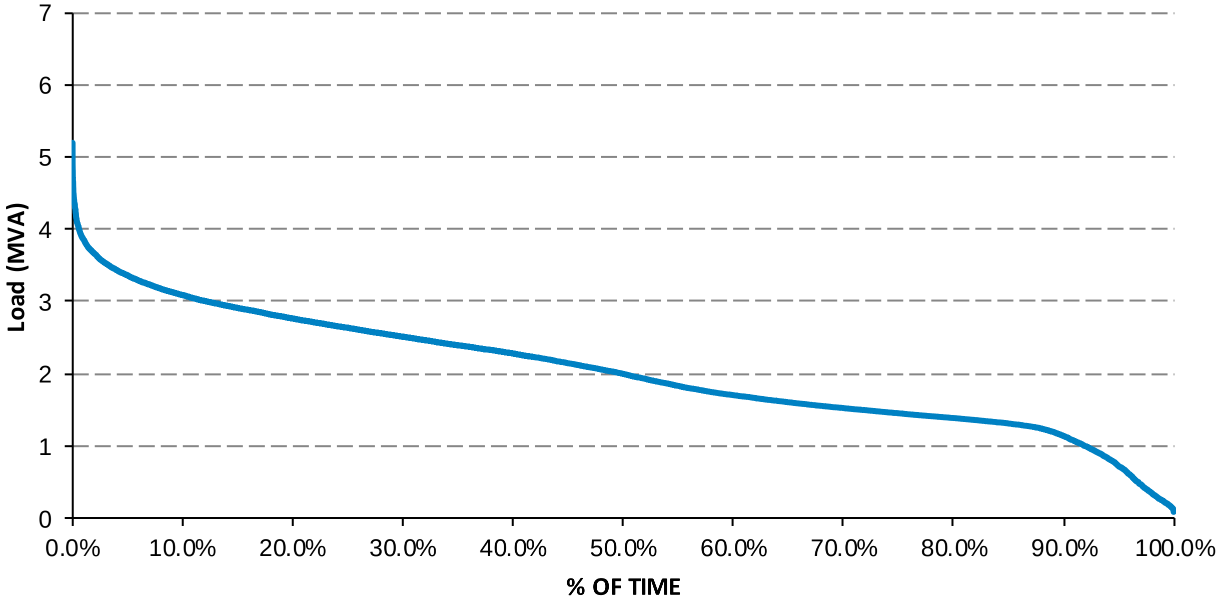


Figure 6: Load duration curve for CLD1A

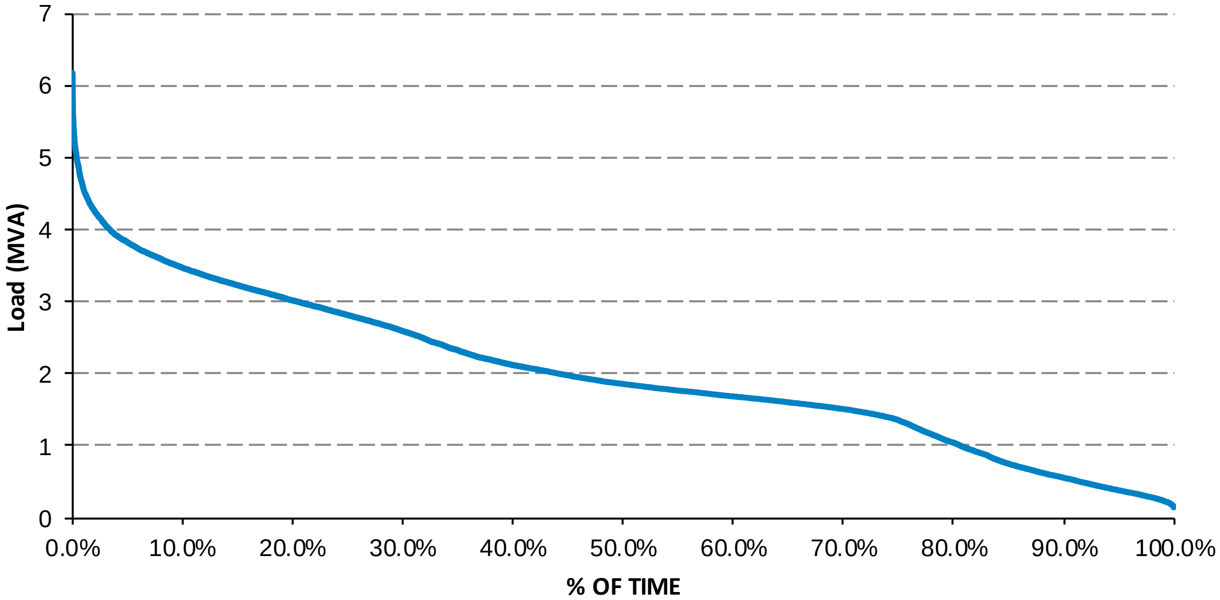


Figure 7: Load duration curve for CLD11

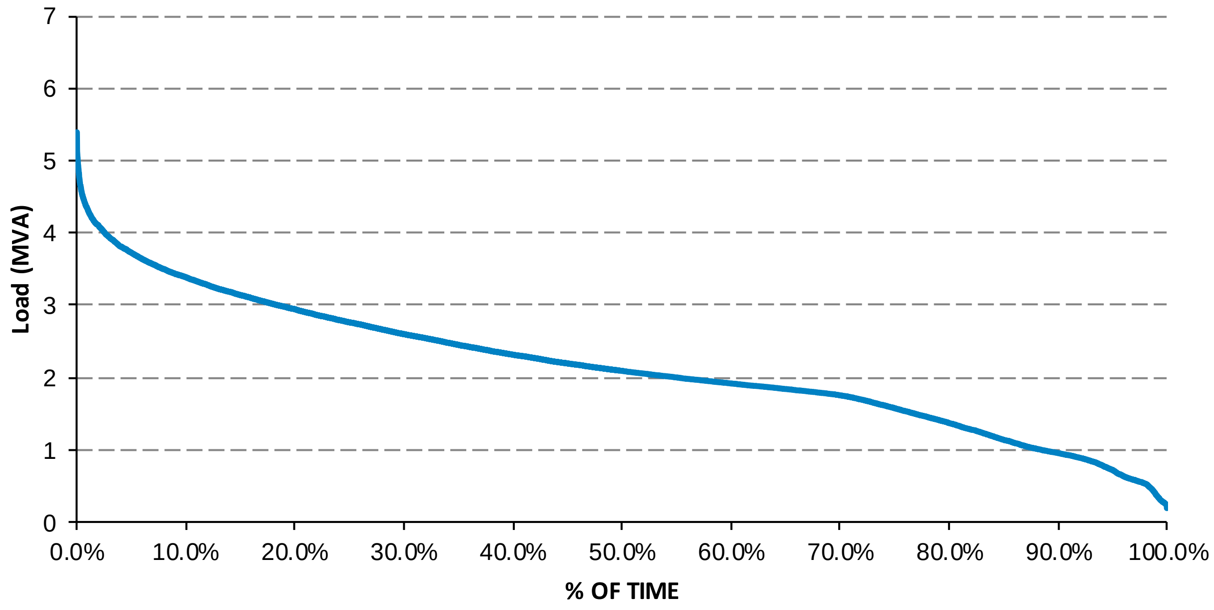


Figure 8: Load duration curve for CLD18A

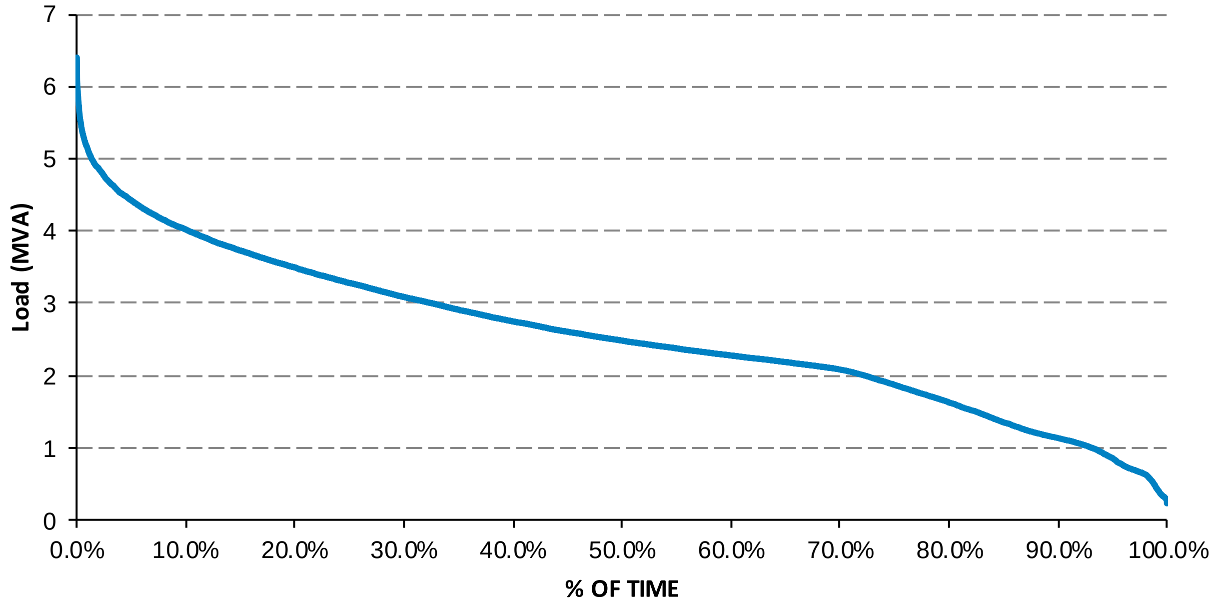


Figure 9: Load duration curve for CLD29A

3. IDENTIFIED NEED

3.1. APPLIED SERVICE STANDARD

Distribution Network

Energex plans its 11kV distribution network for a Target Maximum Utilisation (TMU) of 80% at 50 probability of exceedance (PoE) load. This ensures the feeder is not overloaded whist having sufficient transfer capacity for contingencies on the 11kV network. This level of utilisation also allows transfer capacity to ensure that Energex meets is Safety Net obligations under the Distribution Authority.

Sub-transmission Network

Under its Distribution Authority, Energex must adhere to the Safety Net which identifies the principles that apply to the operation of network assets under network contingency conditions. System contingency related capability is assessed against a 50% PoE forecast load, available load transfers, emergency cyclic capacity (ECC) ratings, non-network response, mobile plant, mobile generators, and short-term ratings of plant and equipment where available. This process allows load at risk under contingency conditions to be identified and assessed. Energex's Distribution Authority can be accessed by the following link:

https://www.dnrme.qld.gov.au/__data/assets/pdf_file/0003/219486/distribution-authority-d0798-energex.pdf

As per the Energex Safety Net criteria, for substations supplying urban load, during a single contingency event, interruption of supply up to 40MVA is permissible for the first 30 minutes, followed by a maximum interruption of up to 12MVA, provided that all load except for up to 4MVA can be restored within 3 hours, and the remaining 4MVA is fully restored within 8 hours. Table 3 below outlines the Safety Net criteria.

Category	Demand Range	Allowed Outage to be OK
Urban	> 40MVA	No outage OK
	12-40MVA	30 minutes OK
	4-12MVA	3 hours OK
	<4MVA	8 hours OK

Table 3: Summary of Safety Net Criteria

Further to an assessment against its Safety Net obligations, Energex also undertake analysis of system capacity under normal conditions with all plant in service against the 10% PoE load. The total capacity of the substation or the system Normal Cyclic Capacity (NCC) limit with all assets in service, shall not be exceeded to avoid reducing its designed life.

3.2. Description of the Identified Need

There are two major identified needs in this NNOR:

- 11kV Feeder limitations – there are currently only 4x11kV feeders in the study area. Without augmentation, these feeders will not be able to provide enough capacity to continue to supply new customers, nor meet Energex's TMU of 80%.

- Safety Net Limitation at SSCLD - where load continues to be added to SSCLD, the redundancy requirement specified in Energex's Distribution Authority will not be achieved.

These limitations are discussed in more detail below.

3.3. Quantification of the Identified Need

3.3.1. Safety Net Non-Compliance

Energex has applied the following assumptions in developing it forecast load for the 11kV feeders in the area:

- In the Aura development, Energex have forecast around 500 additional customers/year between 2020 and 2025. After 2025, this will be around 1,000 customers/year.

- A demand increase is expected of between 1.3kVA/dwelling to 1.6kVA/dwelling which is consistent with the existing demand/customer of the 2,418 customers already connected in the development.

- After 2025, the Sunshine Coast Industrial Park is forecast to increase by around 1MVA/year.

As seen below in Table 4, CLD11 is forecast to exceed its TMU in 2021, with CLD29A, CLD1A and CLD29A all forecast to exceed their TMU in the next ten years. Red cells indicate TMU exceedance.

Year	CLD1A Load (MVA)	CLD11 Load (MVA)	CLD18A Load (MVA)	CLD29A Load (MVA)
80% (TMU)	5.17	5.91	4.89	5.99
2020	4.19	5.64	2.48	4.57
2021	4.25	6.17	2.55	5.01
2022	4.29	6.76	2.65	5.69
2023	4.38	7.07	2.76	6.38
2024	4.53	7.22	2.88	7.30
2025	5.02	7.49	3.87	9.29
2026	5.20	7.73	4.63	11.38
2027	5.38	7.98	5.39	13.48
2028	5.55	8.23	6.34	15.76
2029	5.73	8.48	7.30	18.05
2030	5.90	8.73	8.25	20.53

Table 4: 11kV feeders exceeding Target Maximum Utilisation (TMU) of 80%

Figure 10 to Figure 13 show the proportion of the load duration curve for the 50% POE forecast for each feeder that is above the TMU. Table 5 to Table 8 show the load at risk and the duration of the feeder is above the TMU limits.

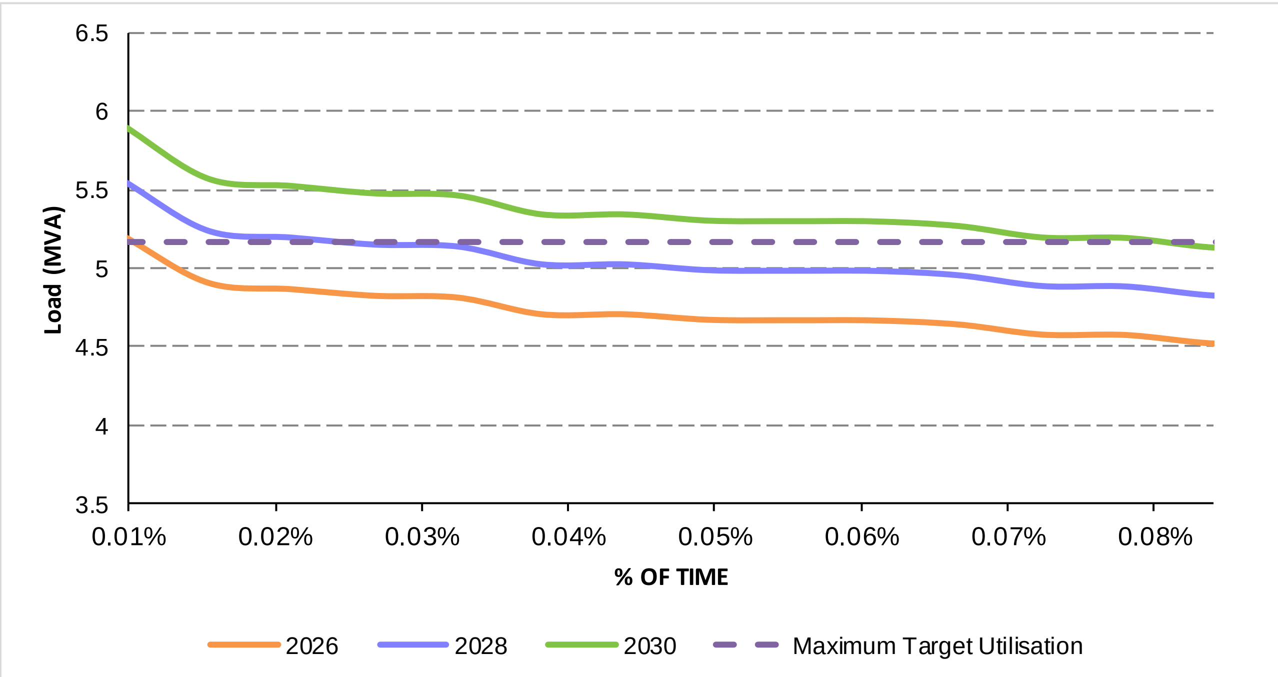


Figure 10: CLD1A Target Maximum Utilisation Limit Exceedance Forecast

Target Maximum Utilisation Limit (MVA)	Year	Forecast 50 PoE Load (MVA)	Load At Risk (MVA)	Days Above Limit	% Time Above Limit	Hrs Over Limit
-	2020	4.19	0.00	-	-	-
-	2021	4.25	0.00	-	-	-
-	2022	4.29	0.00	-	-	-
-	2023	4.38	0.00	-	-	-
-	2024	4.53	0.00	-	-	-
-	2025	5.02	0.00	-	-	-
5.2	2026	5.20	0.03	1	0.01%	0.5
5.2	2027	5.38	0.21	1	0.01%	0.5
5.2	2028	5.55	0.38	1	0.02%	1.5
5.2	2029	5.73	0.56	4	0.04%	3.5
5.2	2030	5.90	0.74	5	0.07%	6.5

Table 5: CLD1A Target Maximum Utilisation Limit

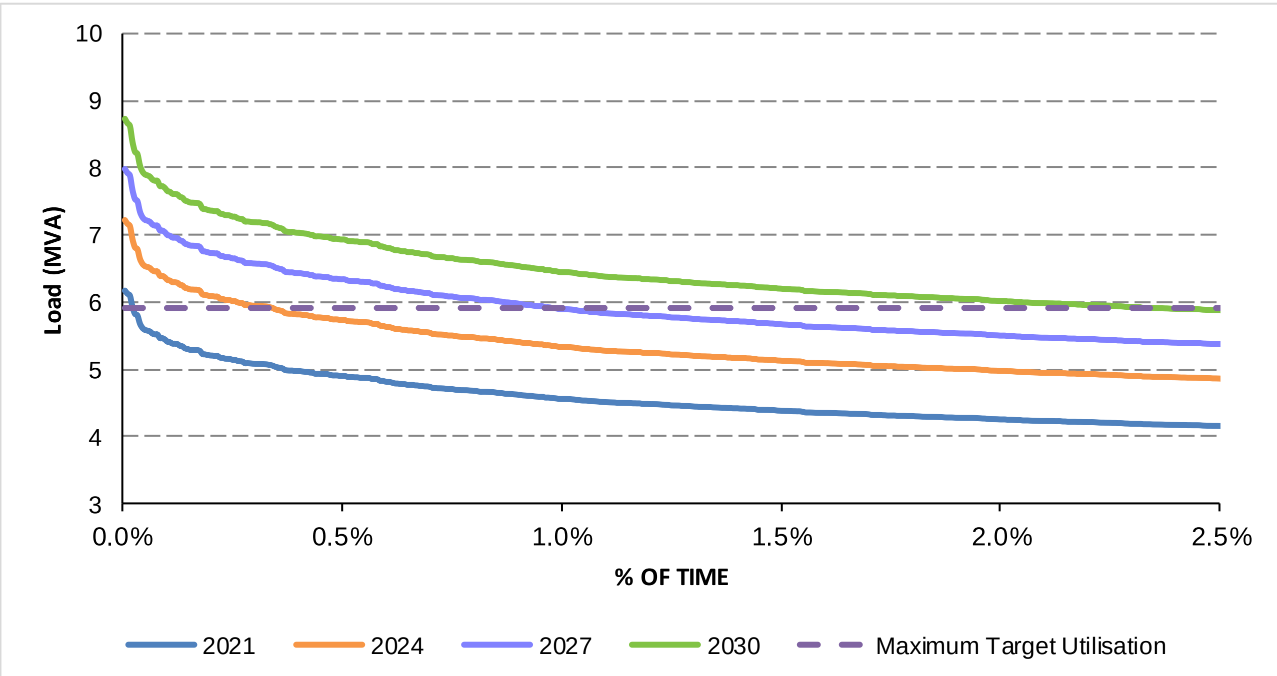


Figure 11: CLD11 Target Maximum Utilisation Limit Exceedance Forecast

Target Maximum Utilisation Limit (MVA)	Year	Forecast 50 PoE Load (MVA)	Load At Risk (MVA)	Days Above Limit	% Time Above Limit	Hrs Over Limit
-	2020	5.64	0.00	-	-	-
5.9	2021	6.17	0.26	1	0.02%	2.0
5.9	2022	6.76	0.85	6	0.11%	9.5
5.9	2023	7.07	1.15	11	0.23%	20.0
5.9	2024	7.22	1.31	17	0.34%	29.9
5.9	2025	7.49	1.57	25	0.54%	46.9
5.9	2026	7.73	1.82	28	0.71%	62.4
5.9	2027	7.98	2.07	39	0.97%	85.3
5.9	2028	8.23	2.32	52	1.34%	117.8
5.9	2029	8.48	2.57	67	1.79%	157.2
5.9	2030	8.73	2.82	88	2.34%	205.1

Table 6: CLD11 Target Maximum Utilisation Limit

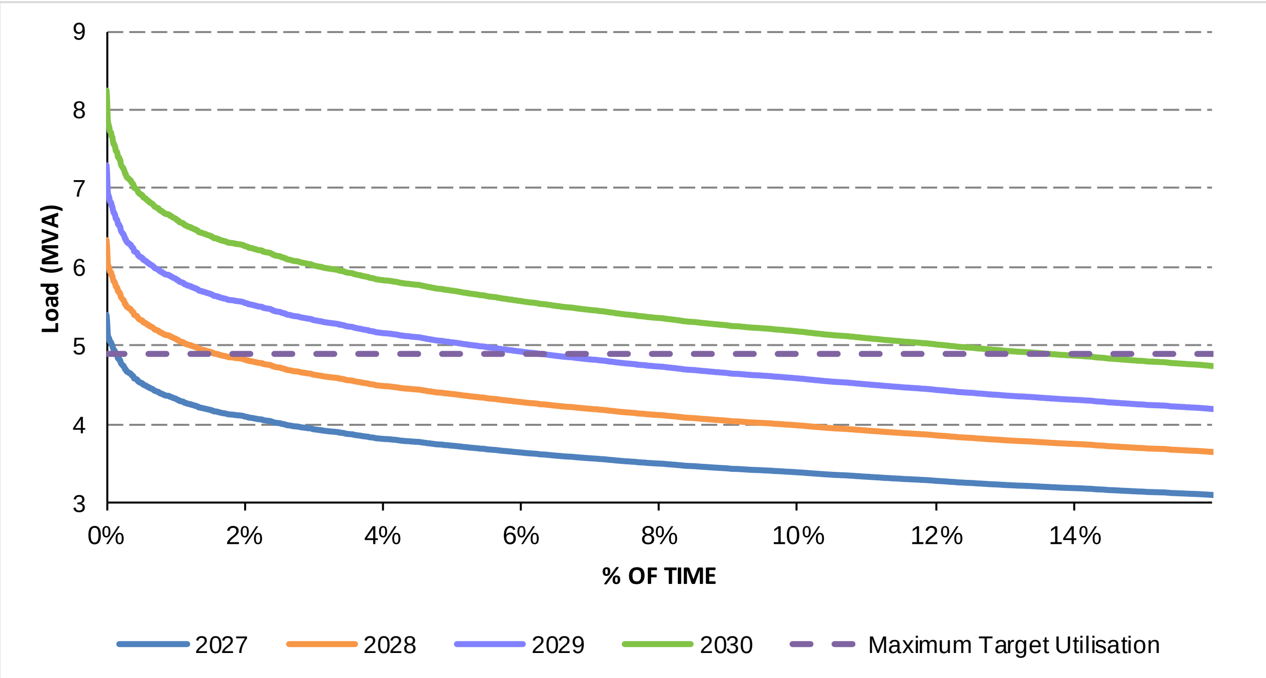


Figure 12: CLD18A Target Maximum Utilisation Limit Exceedance Forecast

Target Maximum Utilisation Limit (MVA)	Year	Forecast 50 PoE Load (MVA)	Load At Risk (MVA)	Days Above Limit	% Time Above Limit	Hrs Over Limit
-	2020	2.48	0.00	-	-	-
-	2021	2.55	0.00	-	-	-
-	2022	2.65	0.00	-	-	-
-	2023	2.76	0.00	-	-	-
-	2024	2.88	0.00	-	-	-
-	2025	3.87	0.00	-	-	-
-	2026	4.63	0.00	-	-	-
4.9	2027	5.39	0.50	9	0.14%	12.0
4.9	2028	6.34	1.45	73	1.60%	140.2
4.9	2029	7.30	2.40	165	6.27%	549.0
4.9	2030	8.25	3.36	252	13.65%	1195.8

Table 7: CLD18A Target Maximum Utilisation Limit

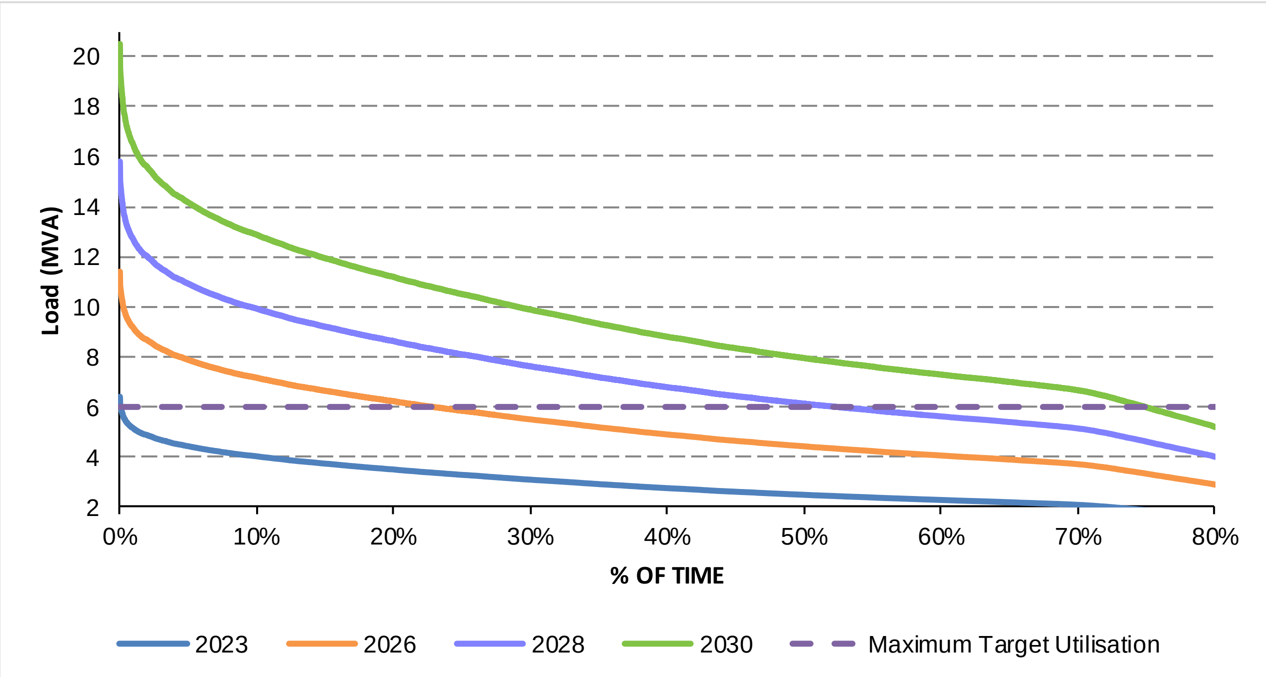


Figure 13: CLD29A Target Maximum Utilisation Limit Exceedance Forecast

Target Maximum Utilisation Limit (MVA)	Year	Forecast 50 PoE Load (MVA)	Load At Risk (MVA)	Days Above Limit	% Time Above Limit	Hrs Over Limit
-	2020	4.6	0.00	-	-	-
-	2021	5.0	0.00	-	-	-
-	2022	5.7	0.00	-	-	-
6.0	2023	6.4	0.41	5	0.05%	4.5
6.0	2024	7.3	1.31	40	0.70%	60.9
6.0	2025	9.3	3.31	204	8.34%	730.2
6.0	2026	11.4	5.41	294	22.93%	2008.3
6.0	2027	13.5	7.51	312	37.07%	3247.1
6.0	2028	15.8	9.81	316	52.46%	4595.6
6.0	2029	18.0	12.01	323	67.78%	5937.7
6.0	2030	20.5	14.51	340	74.97%	6567.0

Table 8: CLD29A Target Maximum Utilisation Limit

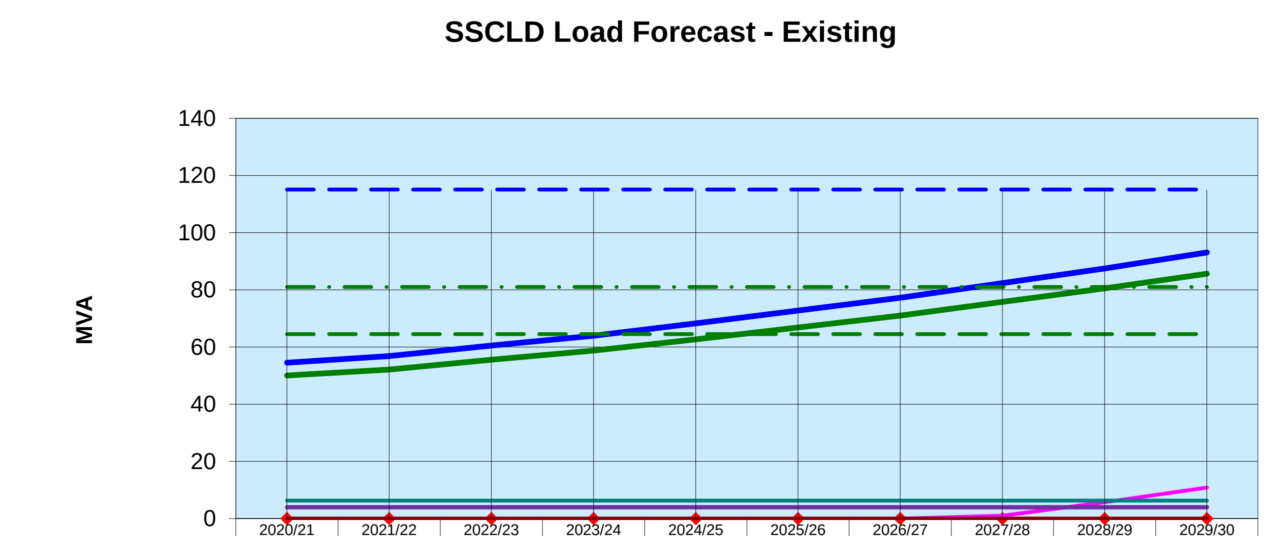
It should be noted that although there is technically an exceedance of the TMU for CLD11 in 2021, this is an extremely small load at risk of 0.26MVA. As such, Energex are not proposing to provide a solution, either network or non-network, to this limitation until 2022.

3.3.2. Future Limitation

SSCLD is equipped with 2 x 60MVA 132/11kV transformers. The substation capacity is limited by the cables from the transformer to the 11kV bus bars and has a NCC, ECC and 2 Hour Emergency Capacity (2HEC) as below:

- NCC – 115.10MVA
- ECC – 64.50MVA
- 2HEC – 81.00MVA

The substation currently has the capacity to supply all forecast loads and meet the Safety Net criteria until 2025. As load in the Aura and surrounding developments continues to grow, Energex forecasts that the Safety Net criteria may not be met somewhere between 2027 and 2030.



	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
10 PoE Load	54.57	56.86	60.56	64.01	68.26	72.79	77.25	82.42	87.53	93.12
Summer NCC	115.10	115.10	115.10	115.10	115.10	115.10	115.10	115.10	115.10	115.10
Load > NCC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
50 PoE Load	50.03	52.14	55.56	58.74	62.68	66.86	71.04	75.83	80.57	85.66
Summer ECC	64.50	64.50	64.50	64.50	64.50	64.50	64.50	64.50	64.50	64.50
Summer 2HEC	81.00	81.00	81.00	81.00	81.00	81.00	81.00	81.00	81.00	81.00
LAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.03	5.77	10.86
RLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Available Transfers	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30
Avail Mobile Eqpt	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

Figure 14: SSCLD Load at Risk

4. TECHNICAL CHARACTERISTICS OF NON-NETWORK OPTIONS

This section describes the technical characteristics of the identified need that a non-network option would be required to comply with.

4.1. Load

To meet Energex's ongoing operational needs, it is expected that any alternate solution must provide stand-alone supply to the distribution network that addresses the substation security standard Load At Risk under System Normal (N) and System Contingency (N-1) as listed in the tables below:

Table 5 to Table 8 illustrates that the amount of time support is required and is forecast to increase yearly.

As part of its operational strategy following a contingency, Energex will deploy 4MVA of generation using its fleet of mobile generators. In addition to the requirements above, Energex would be interested in any network support solutions that provide a cost-effective alternative to this requirement. Submissions to this DPAR should clearly separate their proposal for this extra support opportunity from their proposed solution to the identified need.

Section 3 identifies all the limitations that needs to be addressed.

4.2. Timing

4.2.1. Implementation Timeframe

In order to ensure compliance with Energex's planning criteria and the NER, a non-network solution will need to be implemented by October 2022.

4.3. Compliance with Regulations and Standards

As a distribution network service provider, Energex must comply with regulations and standards, including the Queensland Electricity Act and Regulation, Distribution Authority, NER and applicable Australian Standards.

These obligations must be taken in consideration when choosing a suitable solution to address the identified need at Caloundra as discussed in this RIT-D report.

4.4. Potential Deferred Augmentation Charge

Energex have estimated the capital cost of the network options to within ±40% of estimation accuracy. Using these costs as a guide, a deferral of the limitations represents the following savings per annum:

- Initial Limitation: $85,901
- Future Limitation: $1,884,008

While this should not be considered as the precise deferral cost available to a non-network proponent, it serves as a guide for interested parties to determine the viability of their proposal. Depending on the proposal, Energex may be required to establish some network such as an 11kV feeder ties to facilitate the solution, and where this is the case the deferral amount would be calculated on the quantum of capital and operating expense that is avoided.

Energex will work with successful non-network proponents based on the specifics of what the proponents offer and any necessary further works that Energex may have to undertake to ensure the reliability, security and safety of the network are maintained.

4.5. Feasible vs Non-Feasible Options

4.5.1. Potentially Feasible Options

The identified need presented in this DPAR is driven by the 11kV feeder exceeding the TMU. As such, solutions that prudently and efficiently address these constraints will be considered.

In respect of the requirements under 5.17.4(j) of the NER, any non-network option will contribute to power system security and reliability to the extent that the solution solves the Safety Net limitation. The contribution to power system fault levels is not an issue for this limitation.

A non-exhaustive list of potentially feasible options includes:

- Embedded dispatchable network generation
- Embedded energy storage systems
- Embedded energy storage systems combined with Generation (possibly dispatchable or non-dispatchable)
- Load curtailment agreements with customers to disconnect from the network following a contingency.

It should be noted that the above options may be aggregated across multiple substations and feeders in the network. For example, embedded solutions or load curtailment options could be implemented in the supply areas of SSCLD to provide the required network support.

Although the TMU and emerging Safety Net constraints must be addressed, these are minimum requirements and solutions that can provide greater capacity to the network and improved reliability and security of supply may be considered. Furthermore, if a proponent is unable to support the total load required, Energex still encourages the submission of any solutions to reduce the constraints as it may be possible to aggregate multiple proposals to address the limitation or to have a hybrid solution with a potential network solution.

4.5.2. Options that are Unlikely to be Feasible

Without attempting to limit a potential proponent's ability to innovate when considering opportunities, some technologies / approaches are unlikely to represent a technically or financially feasible solution.

A non-exhaustive list of options that are unlikely to be feasible includes:

- Renewable generation not coupled with energy storage and/or dispatchable generation
- Unproven, experimental or undemonstrated technologies

4.5.3. Timing of Feasible Options

The limitations presented in this report are for the summer period of from 2022 onwards. Energex will be seeking responses from interested parties who are able to provide network support to reduce or eliminate this limitation starting from 2022 in a cost-effective manner. Any proposed solution must at least be available by October 2022, when the initial network solution is currently forecast to be able to be delivered. Solutions to future limitations on the 11kV feeders and at SSCLD will need to be progressively available from 2025 and beyond.

5. CREDIBLE OPTIONS ASSESSED

5.1. Assessment of Network Solutions

5.1.1. Initial Limitation Network Option Identified

The option considered to resolve CLD11 exceeding TMU is to establish a new feeder from SSCLD to Aura. The cost of establishing this new feeder is approximately $3 million, with an operating cost of around $6,861/year. Energex are currently proposing to establish this feeder in October 2022. The works involved to implement this option are:

- Establish 8km 11kV feeder in both new and existing conduits
- Install 800m conduit

5.1.2. Future Limitation Network Options Identified

A total of 9 network options were identified to resolve the identified limitations. Table 9 gives a summary, the initial capital costs and forecast yearly operating costs. Further details of each option can be found in Appendix B.

Option	Option Name	Initial Capital Cost	Operating Cost/Year	NPV
1	11kV Feeders from SSCLD, 132kV Feeders, 132/11kV Bells Creek Central Substation*	$4,257,500	$6,004	-$84,480,000
2	132kV Feeders from F803 & 132/11kV Bells Creek Central Substation	$60,878,334	$152,597	-$75,867,000
3	11kV Feeder from SSCLD & 132kV Feeders (Disconnected), 132/11kV Bells Creek Central Substation	$41,278,348	$112,053	-$77,765,000
4	132kV Feeders & 132/11kV Bells Creek North Substation	$57,420,017	$116,955	-$82,812,000
5	132/33kV Meridan Plains Substation, 33kV Feeders & 33/11kV Bells Creek Central Substation	$53,844,406	$143,424	-$79,444,000
6	132/33/11kV Meridan Plains Substation & 33kV Feeders @11kV, 33/11kV Bells Creek Central Substation	$44,096,500	$101,354	-$79,873,000
7	132/33kV & 33/11kV Meridan Plains Substation & 33kV Feeders @11kV, 33/11kV Bells Creek Central Substation	$44,528,189	$103,370	-$80,443,000
8	132kV Feeders from Mark Rd East (83%UG 17%OH) & 132/11kV Bells Creek Central Substation	$63,167,951	$125,599	-$92,154,000
9	132kV Feeders from SSCLD (88%UG 12%OH) & 132/11kV Bells Creek Central Substation	$51,532,504	$102,683	-$100,969,000

Table 9: Future Limiation Network Options

* It should be noted that Option 1 requires a new 11kV feeder every two years to continue supplying the load. Even though the upfront cost is lower, in NPV terms this has a worse economic outcome.

5.2. Preferred Network Option

In order to resolve the **initial** limitation for CLD11 exceeding the TMU, the identified network option is to establish a new 11kV feeder to de-load CLD11. This option is estimated approximately $3 million and the works involved to implement this option are:

- Establish 8km 11kV feeder
- Install 800m conduit

Option 2 is currently the preferred network option to resolve the **future** 11kV feeder limitations and emerging Safety Net limitation at SSCLD. This provides the most economically efficient network option, with the lowest NPV cost to address the network limitations. It is proposed to establish Bell's Creek Central substation in October 2025. Works include:

- Installation of 2 x 13km of 132kV overhead feeders;
- installation of 132kV CBs:
  - 2 x bus sections with 1 x bus section CB
  - 1 x transformer CB
  - 2 x feeder CBs;
- installation of 132kV control room;
- installation of 1 x 60MVA 132/11kV transformers;
- installation of an 11kV indoor switchroom including 1 x bus section with 1 x bus section CB, 1 x transformer CB, 5 x feeder CBs;
- installation of 1 x AFLC;

The preferred network option has an estimated initial capital project cost of $60.7M, and an annual operating cost of approximately $152,597/year. It should be noted that although this option has a higher initial capital cost than Option 1, the future stages associated with Option 1, which is essentially to establish a new 11kV feeder every two years, is not the most economically efficient solution in NPV terms.

6. SUMMARY OF SUBMISSIONS RECEIVED IN RESPONSE TO NON NETWORK OPTIONS REPORT

On 16 November 2020, Energex published the Non-Network Options Report (NNOR) providing details on the identified need at Caloundra zone substation. 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 NNOR, Energex received one submission:

- Establish a single 24MW/39.75MWh battery system to allow for restoration of supply.

6.1. Submissions Received which are Potentially Credible Options

6.1.1. Option 10: Contract a 24MW/39.75MWh Battery Energy Storage Solution (BESS)

This option involves contracting a proponent to provide multiple 24MW/39.75MWh BESS totalling 24MW/39.75MWh for an 8-year period to eliminate load at risk in the vicinity of SSCLD from 2022. The BESS will be fully charged and ready to provide peak load relief. At the end of the period of the contract, a new zone substation is proposed to be established to eliminate the load at risk.

7. MARKET BENEFIT ASSESSMENT METHODOLOGY

The identified need outlined in the DPAR is a regulatory obligation to address the substation limitation as outlined in the Distribution Authority. Because of this, the assessment methodology is a lowest cost process, rather than a cost/benefit analysis based on market benefits. There is no material difference in specific market benefits, such as Value of Customer Reliability between identified Network and Non-Network Options. As such, no Market Benefits have been calculated for use in the economic analysis to identify the preferred option.

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).

8. DETAILED ECONOMIC ASSESSMENT

8.1. 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.

For the identified need presented in this DPAR, a Weighted Average NPV, based on a sensitivity analysis, was conducted to establish the option that remained the lowest cost option in the scenarios considered. In effect, this means that Energex create a separate NPV for each scenario, assign a weighting to each, with the outcome a Weighted Average NPV to inform the lowest cost option in a range of scenarios to proceed with.

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.

8.2. Key Variables and Assumptions

8.2.1. Discount Rate

Calculations for annual deferral values of projects are based on Energex's regulated pre-tax real Weighted Average Cost of Capital (WACC). This value is prescribed by the AER for a specific regulatory control period. The identified need described in this DPAR occurs in the 2020-2025 regulatory control period, where the WACC is 2.62%.

8.2.2. Cost Estimates

Project costs are calculated using standard estimate components which are developed and evaluated by estimation teams in Energex. The costs are split into 2 components: direct cost, which is the costs which are directly costed to the project; and indirect costs which cover overheads associated with the business. All costs provided in this report are estimated to fall within ± 40% accuracy of the stated cost.

8.2.3. Evaluation Test Period

Consideration of network options is assessed over an evaluation period of 60 years.

8.3. 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. This scenario has been assigned a likelihood of 50% 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 has been used. This scenario has been assigned a likelihood of 20% in the weighted average NPV.
3. **Low demand** – under this scenario the only change from the Medium Growth scenario is that the low growth load forecast has been used. This scenario has been assigned a likelihood of 30% in the weighted average NPV.

8.4. Net Present Value (NPV) Results

Table 10 shows the Weighted Average NPV results for the identified options. The NPV cost results have been withheld for Option 10 as it is based on the submission to the NNOR that was received, which Energex and the proponent considers to be Commercial-in-Confidence.

Option	Option Name	Rank	Initial Capital Cost	NPV ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
1	Supply New Demand with 11kV Feeders from SSCLD	8	$4,257,500	-$84,480,000	-$79,812,000	-$4,668,000
2	Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment	1	$60,878,334	-$75,867,000	-$71,414,000	-$4,453,000
3	Supply New Demand with 11kV Feeders from SSCLD and Establish 132kV Feeders, then Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment	3	$41,278,348	-$77,765,000	-$73,251,000	-$4,514,000
4	Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek North Establishment	7	$57,420,017	-$82,812,000	-$79,036,000	-$3,775,000
5	Supply New Demand with 33kV Feeders from Meridan Plains Establishment to Bell's Creek Central Establishment	4	$56,444,406	-$79,444,000	-$74,582,000	-$4,863,000
6	Supply New Demand with 33kV Feeders from Meridan Plains (132/33/11kV) Establishment to Bell's Creek Central Establishment	5	$46,767,929	-$79,873,000	-$75,152,000	-$4,721,000
7	Supply New Demand with 33kV Feeders from Meridan Plains (132/33kV, 33/11kV) Establishment to Bell's Creek Central Establishment	6	$47,199,618	-$80,443,000	-$75,718,000	-$4,725,000
8	Supply New Demand with 132kV Feeders (Tee off at Mark Rd East) to Bell's Creek Central Establishment	9	$63,167,951	-$92,154,000	-$87,681,000	-$4,473,000
9	Supply New Demand with 132kV Feeders from Caloundra Substation to Bell's Creek Central Establishment	10	$51,532,504	-$100,969,000	-$96,037,000	-$4,932,000
10	Install 24MW Battery	2	Withheld	Withheld	Withheld	Withheld

Table 10: Weighted Average NPV Results

8.5. Selection of Preferred Option

The preferred option remains to be Option 2.

8.6. 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.

9. SUBMISSION AND NEXT STEPS

9.1. Submissions from Solution Providers

Energex invites written submissions to address the identified need in this report from registered participants and interested parties.

Energex will not be legally bound in any way or otherwise obligated to any person who may receive this RIT-D report or to any person who may submit a proposal. At no time will Energex be liable for any costs incurred by a proponent in the assessment of this RIT-D report, any site visits, obtainment of further information from Energex or the preparation by a proponent of a proposal to address the identified need specified in this RIT-D report.

The RIT-D process is aimed at identifying a technically feasible non-network alternative to the internal option that has greater net economic benefits. However, the selection of the solution provider to implement the preferred option will be done after the conclusion of the Final Project Assessment Report (FPAR) and in accordance with Energex's standards for procurement.

Submissions in writing are due by 4pm on the **8 October 2021** and should be lodged to demandmanagement@energex.com.au

9.2. Next Steps

Following Energex's consideration of submissions received in response to this report, the preferred option, and a summary of and commentary on any submissions received will be included as part of the FPAR. The FPAR represents the final stage of the consultation process in relation to the application of the RIT-D.

Energex intends to publish the FPAR no later than 11 October 2021. Energex will use its reasonable endeavours to publish the FPAR by the above date. This may however not be achievable due to changing power system conditions or other circumstances beyond the control of Energex.

At the conclusion of the consultation process, Energex intends to take steps to progress the recommended solution(s) to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvement(s), as necessary.

Please note that at the conclusion of the FPAR, for Energex to act on a submission from a non-network proponent, Energex will need to enter into a legally binding contract with that non-network proponent for delivery of the non-network solution within a timeframe satisfactory to Energex to ensure timely completion of the project. Failure to enter into a contract within a satisfactory timeframe will result in Energex reverting to the next preferred credible option identified as part of the preferred option published in the FPAR.

Step 1	Publish Non-Network Options Report inviting non-network options from interested participants	Date Released: **16 November 2020**
Step 2	Consultation period	**Concluded**
Step 3	Release of Draft Project Assessment Report (DPAR)	Date Released: **13 August 2021**
Step 4	Submissions in response to the Draft Project Assessment Report (DPAR)	**Due Date: 8 October 2021**
Step 5	Consultations in response to the DPAR	**Minimum of 6 weeks**
Step 6	Publish the Final Project Assessment Report (FPAR)	Anticipated to be released by: **19 November 2021**
Energex reserves the right to revise this timetable at any time. The revised timetable will be made available on the Energex RIT-D website.		

Energex will take all reasonable efforts to maintain the consultation schedule listed above. Due to various circumstances the schedule may change, however, up-to-date information will be available on the Energex website.

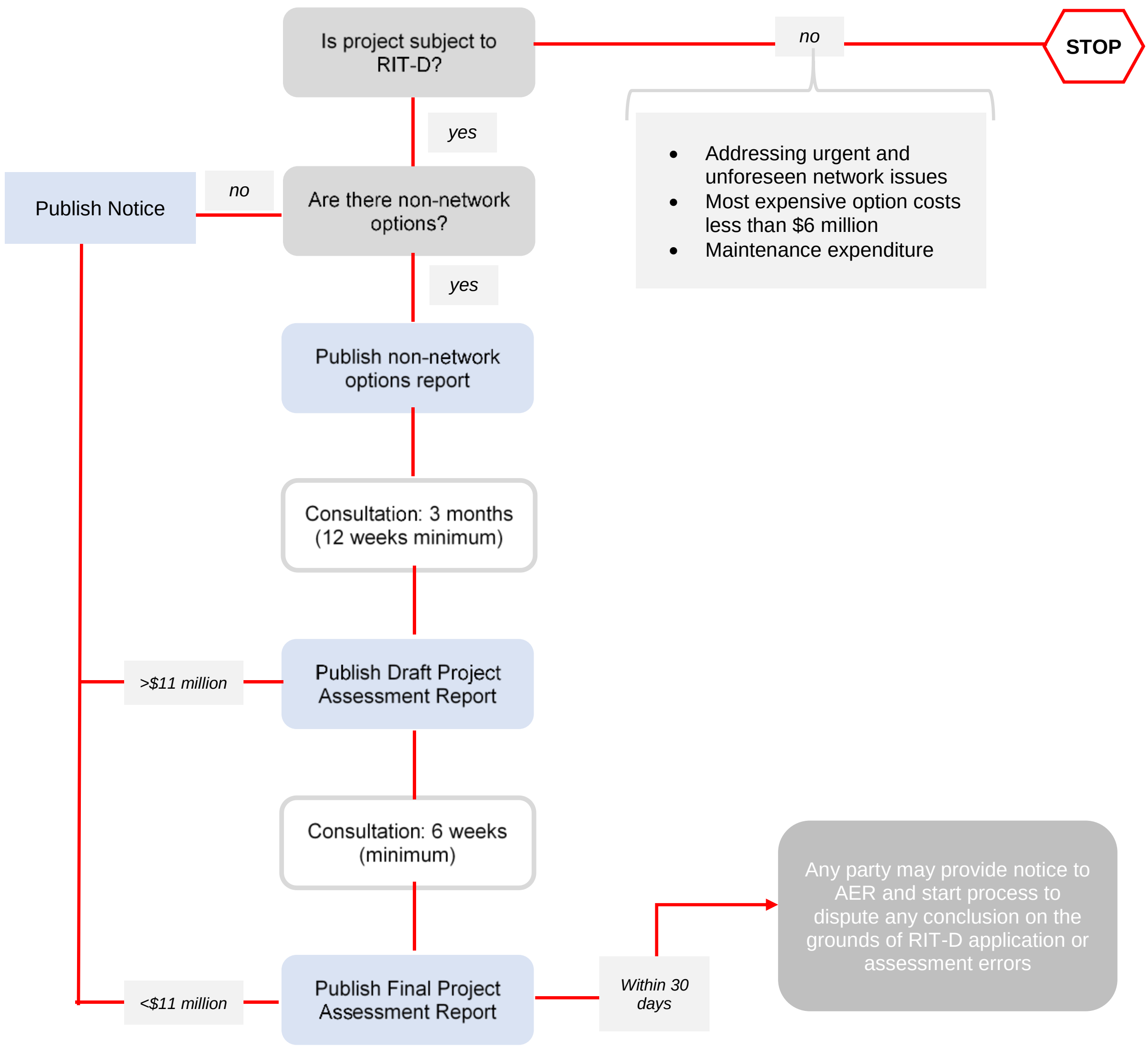
During the consultation period, Energex will review, compare and analyse all internal and external solutions. Detailed economic options analysis and comparisons of expected market benefits will be undertaken during this time. At the end of the consultation and review process Energex will publish a final report which will detail the most feasible option and proceed to implement that option.

10. COMPLIANCE STATEMENT

This DPAR 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 NNOR;	6
(4) a description of each credible option assessed	5 & 6
(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	7
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	5 & 6
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	7
(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	7
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	8.4
(10) the identification of the proposed preferred option	8.5
(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	8.5 & 8.6
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	9.1

Appendix A – The Rit-D Process



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

Appendix B – Future Limitation Network Options

The following sections outline the identified Network Options in more detail.

Option 1: Supply New Demand with 11kV Feeders from SSCLD, then Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment

This option involves continuing to supply the Aura subdivision and surrounding area with 11kV feeders from SSCLD until an additional 132/11kV substation is triggered by the Safety Net limitation at SSCLD. The costs for 11kV feeders have been determined individually considering conduit requirements, civil and other works in each case. Standard costs include $1300/m for conduit installation (6 conduits), plus $250/m for cable installation.

The works required to implement this option are:

- Establish 11kV feeders from SSCLD to supply Aura up to 2029
- Establish 2 x 132kV feeders to Bell's Creek Central, establish Bell's Creek Central 132/11kV zone substation in 2029 to supply the continued load growth in the area and address the safety net limitation at Caloundra. In this case it is assumed the 132kV feeders are constructed overhead for the first 9km and underground for the remaining 4km based on the timing of the works;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/11kV transformer in 2031 at Bell's Creek Central;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.
- Estimated initial capital cost: $4.2 million ± 40% (2026)
- Estimated initial operating cost per annum: $6,004 (2026)

A schematic diagram of the proposed solution is shown in Figure 15 below.

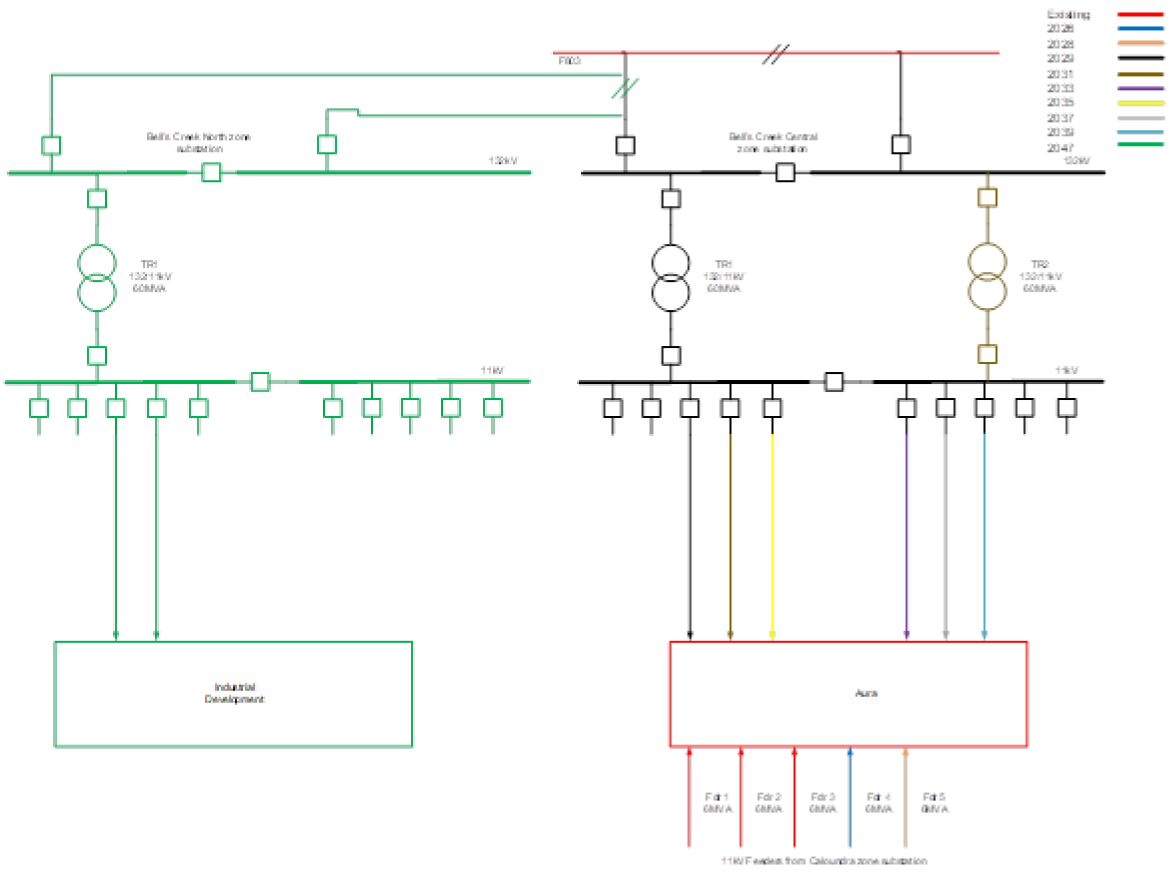


Figure 15: Proposed network arrangement under option 1

Option 2: Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment

This option involves supplying the Aura subdivision and surrounding area with 11kV feeders from a new substation at Bell's Creek central.

The works required to implement this option are:

- Establish Bell's Creek Central 132/11kV zone substation in 2026 with the following:
  - single 132/11kV transformer,
  - associated switchgear,
  - 13km of 132kV overhead double circuit line;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/11kV transformer in 2029 at Bell's Creek Central;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.
- Estimated initial capital cost: $60.8 million ± 40% (2026)
- Estimated initial operating cost per annum: $152,597 (2026)

A schematic diagram of the proposed solution is shown in Figure 16 below.

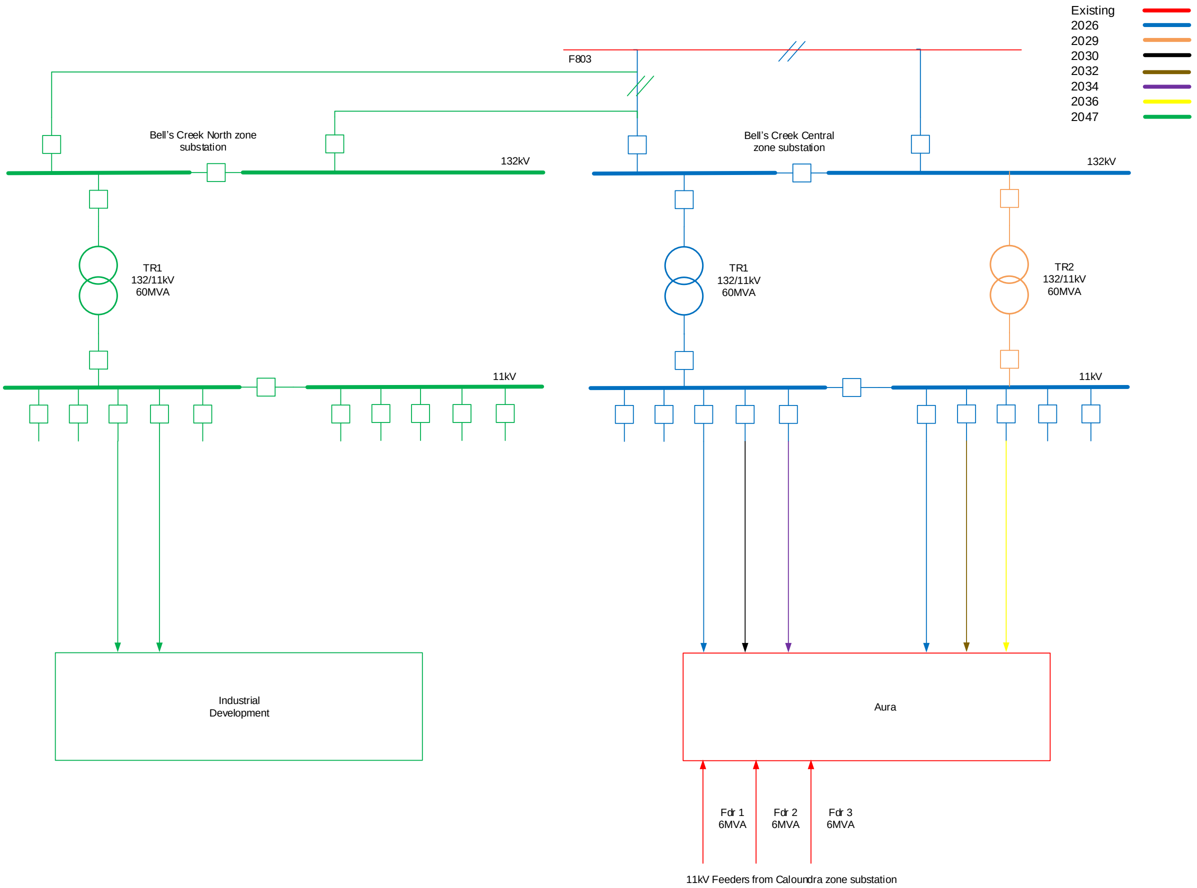


Figure 16: Proposed network arrangement under option 2

Option 3: Supply New Demand with 11kV Feeders from SSCLD and Establish 132kV Feeders, then Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek Central Establishment

This option involves establishing the 132kV double circuit line to Bell's Creek central and utilising it only when required at 132kV. This option de-risks the later construction of underground 132kV. An 11kV feeder from Caloundra will be established to supply the Aura subdivision and surrounding area to delay the establishment of the Bell's Creek Central substation.

The works required to implement this option are:

- Establish 13km of 132kV overhead double circuit line and one 11kV feeder to from Caloundra 11kV in 2026;
- Establish Bell's Creek Central 132/11kV zone substation in 2028 with the following:
  - single 132/11kV transformer,
  - associated switchgear,
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/11kV transformer in 2030 at Bell's Creek Central;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth
- Estimated initial capital cost: $41 million ± 40% (2026)
- Estimated initial operating cost per annum: $112,053 (2026)

A schematic diagram of the proposed solution is shown in Figure 17 below.

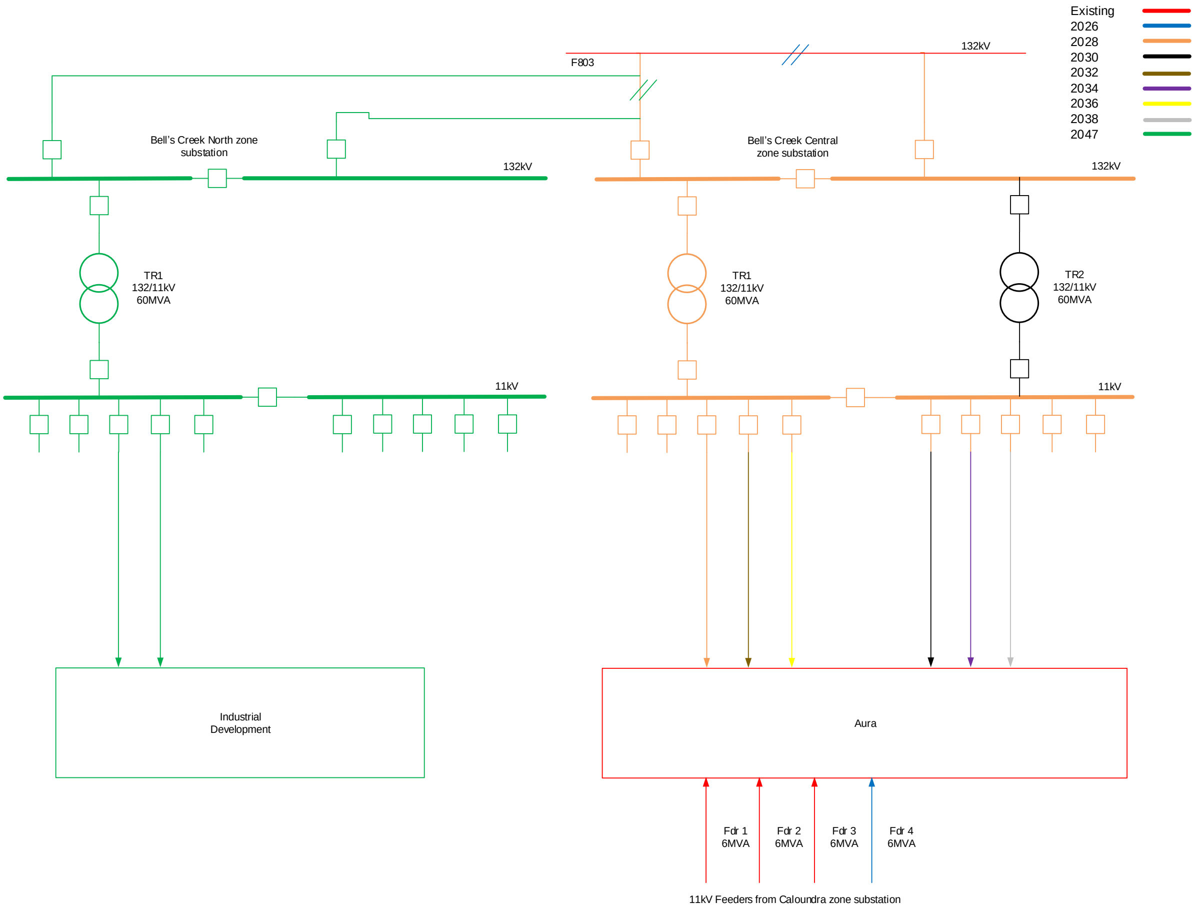


Figure 17: Proposed network arrangement under option 3

Option 4: Supply New Demand with 132kV Feeders (Tee off at Meridan Plains) to Bell's Creek North Establishment

This option involves establishing a new substation at Bell's Creek North to supply the Aura subdivision and surrounding area.

The works required to implement this option are:

- Establish Bell's Creek North 132/11kV zone substation in 2026 with the following:
  - single 132/11kV transformer,
  - associated switchgear,
  - 8km of 132kV overhead double circuit line;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/11kV transformer in 2029 at Bell's Creek North;
- Establish Bell's Creek Central 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.
- Estimated initial capital cost: $57.1 million ± 40% (2026)
- Estimated initial operating cost per annum: $116,955 (2026)

A schematic diagram of the proposed solution is shown in Figure 18 below.

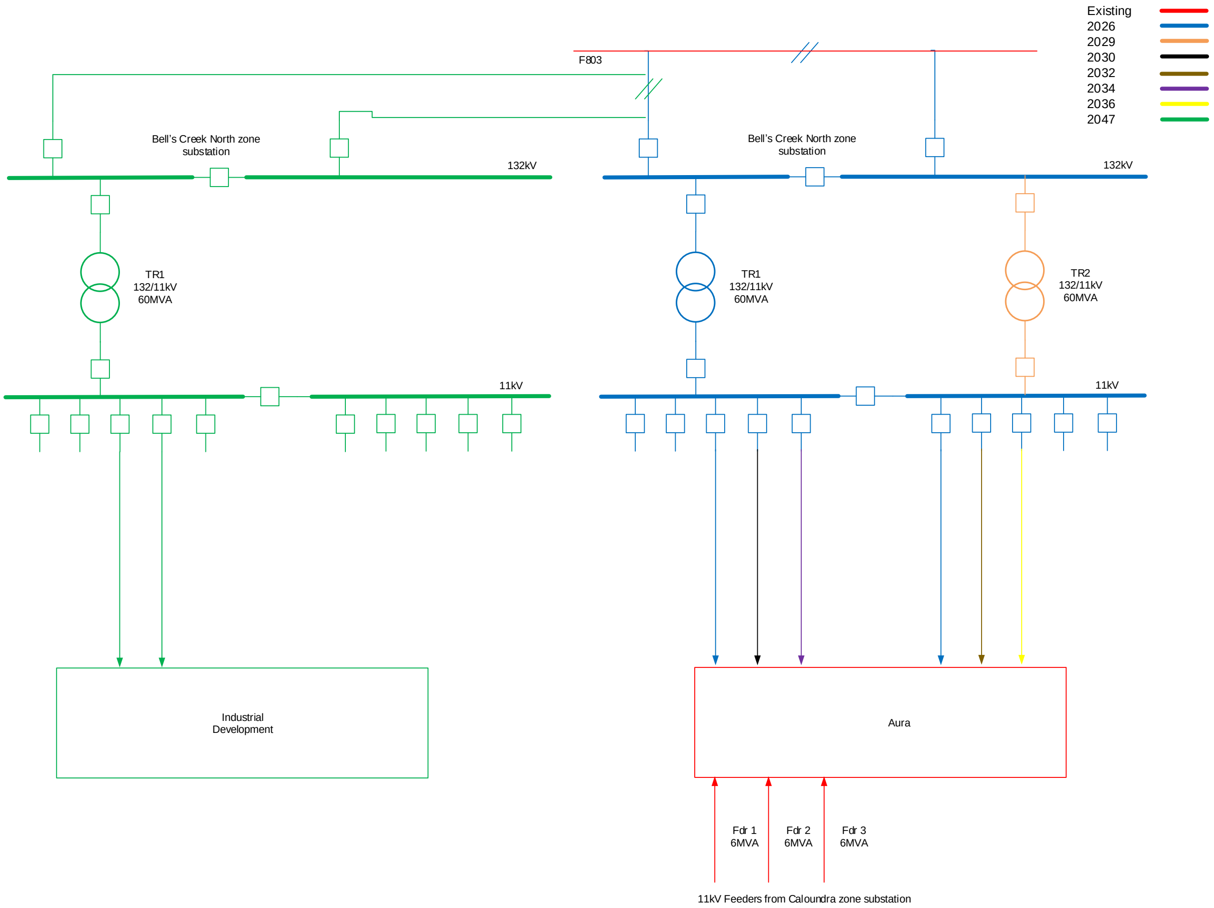


Figure 18: Proposed network arrangement under option 4

Option 5: Supply New Demand with 33kV Feeders from Meridan Plains Establishment to Bell's Creek Central Establishment

This option involves establishing a new 132/33kV substation at Meridan Plains and a new 33/11kV substation at Bell's Creek central.

The works required to implement this option are:

- Establish Meridan Plains 132/33 kV zone substation in 2026 with the following:
    - single 132/33kV transformer,
    - associated switchgear,
    - 13km of 33kV overhead double circuit line to Bell's Creek Central;
- Establish Bell's Creek central 33/11kV zone substation in 2026 with the following:
    - single 33/11kV transformer,
    - associated switchgear;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/33kV and 33/11kV transformer in 2029 at Meridan Plains and Bell's Creek Central respectively;
- Establish Bell's Creek North 33/11kV zone substation with a single 33/11kV transformer in 2040 and a second 33/11kV transformer in 2044 based on continued demand growth.
- Estimated initial capital cost: $53.6 million ± 40% (2026)
- Estimated initial operating cost per annum: $143,424 (2026)

A schematic diagram of the proposed solution is shown in Figure 19 below.

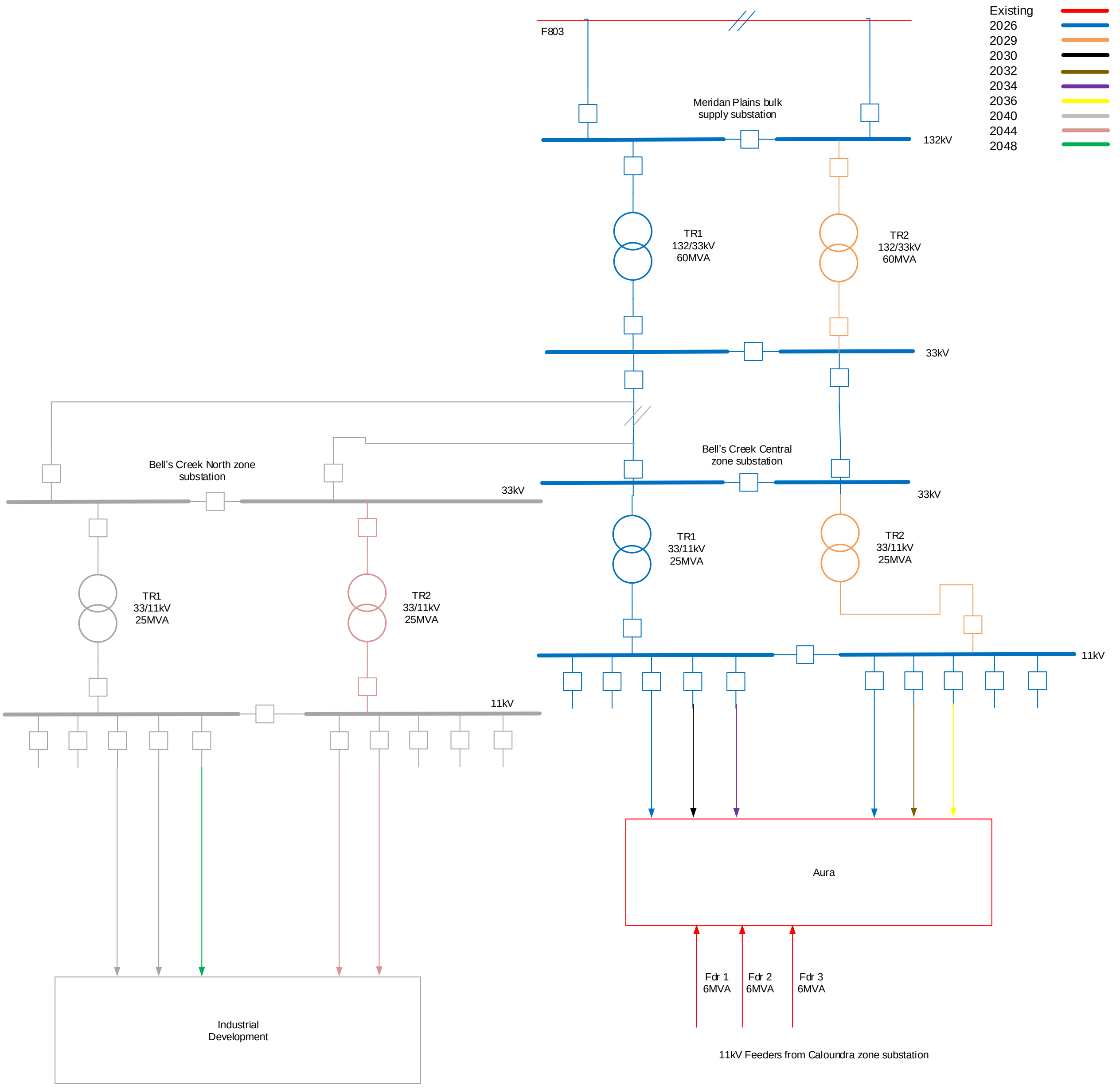


Figure 19: Proposed network arrangement under option 5

Option 6: Supply New Demand with 33kV Feeders from Meridan Plains (132/33/11kV) Establishment to Bell's Creek Central Establishment

This option involves establishing the 132kV double circuit line to Bell's Creek central and utilising it only when required at 132kV. This option de-risks the later construction of underground 132kV. An 11kV feeder from Caloundra will be established to supply the Aura subdivision and surrounding area to delay the establishment of the Bell's Creek Central substation.

The works required to implement this option are:

- Establish Meridan Plains Bulk supply substation in 2026 with the following:
  - single multivoltage 132/33/11kV transformer (Big Bertha),
  - associated switchgear,
  - 4 voltage regulators at Aura,
- 13km of 33kV overhead double circuit line to Aura (utlizied at 11kV);
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/33/11kV Big Bertha transformer at Meridan Plains in 2028;
- Establish Bell's Creek Central 33/11kV zone substation in 2031 with the following:
  - two 33/11kV transformers,
  - associated switchgear;
- Establish Bell's Creek North 33/11kV zone substation with a single 33/11kV transformer in 2040 and a second 33/11kV transformer in 2044 based on continued demand growth.
- Estimated initial capital cost: $43.9 million ± 40% (2026)
- Estimated initial operating cost per annum: $101,354 (2026)

A schematic diagram of the proposed solution is shown in Figure 20 below.

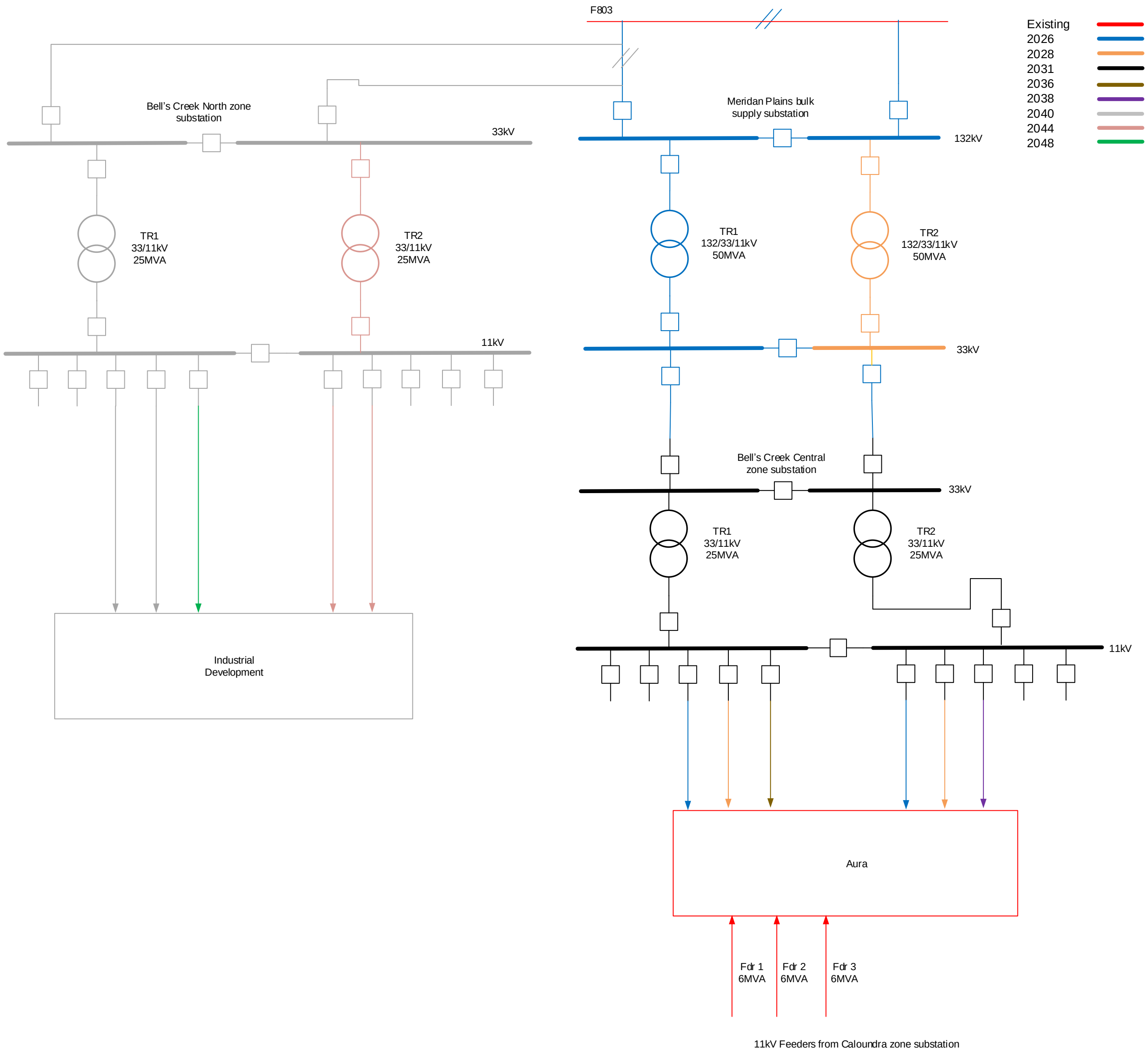


Figure 20: Proposed network arrangement under option 6

Option 7: Supply New Demand with 33kV Feeders from Meridan Plains (132/33kV, 33/11kV) Establishment to Bell's Creek Central Establishment

This option involves establishing a new 132/11kV and 33/11kV substation at Meridan Plains and establishing the 33kV double circuit line to Bells Creek central and utilising it initially at 11kV to supply the Aura subdivision and surrounding area. This option de-risks the later construction of underground 33kV by constructing it in 2026 and utilising it at 33kV only when required in 2031.

The works required to implement this option are:

- Establish Meridan Plains bulk supply substation in 2026 with the following:
  - single 132/33kV transformer,
  - single 33/11kV transformer,
  - 4 voltage regulators at Aura,
- 13km of 33kV overhead double circuit line to Aura (utlizied at 11kV);
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/33kV transformer at Meridan Plains in 2028;
- Establish the 2nd 33/11kV transformer at Bell's Creek Central in 2028;
- Establish Bell's Creek Central 33/11kV zone substation in 2031 with the following:
  - reuse the two 33/11kV transformers from Meridan Plains
  - associated switchgear;
- Establish Bell's Creek North 33/11kV zone substation with a single 33/11kV transformer in 2040 and a second 33/11kV transformer in 2044 based on continued demand growth.
- Estimated initial capital cost: $44.2 million ± 40% (2026)
- Estimated initial operating cost per annum: $103,370 (2026)

A schematic diagram of the proposed solution is shown in Figure 21 below.

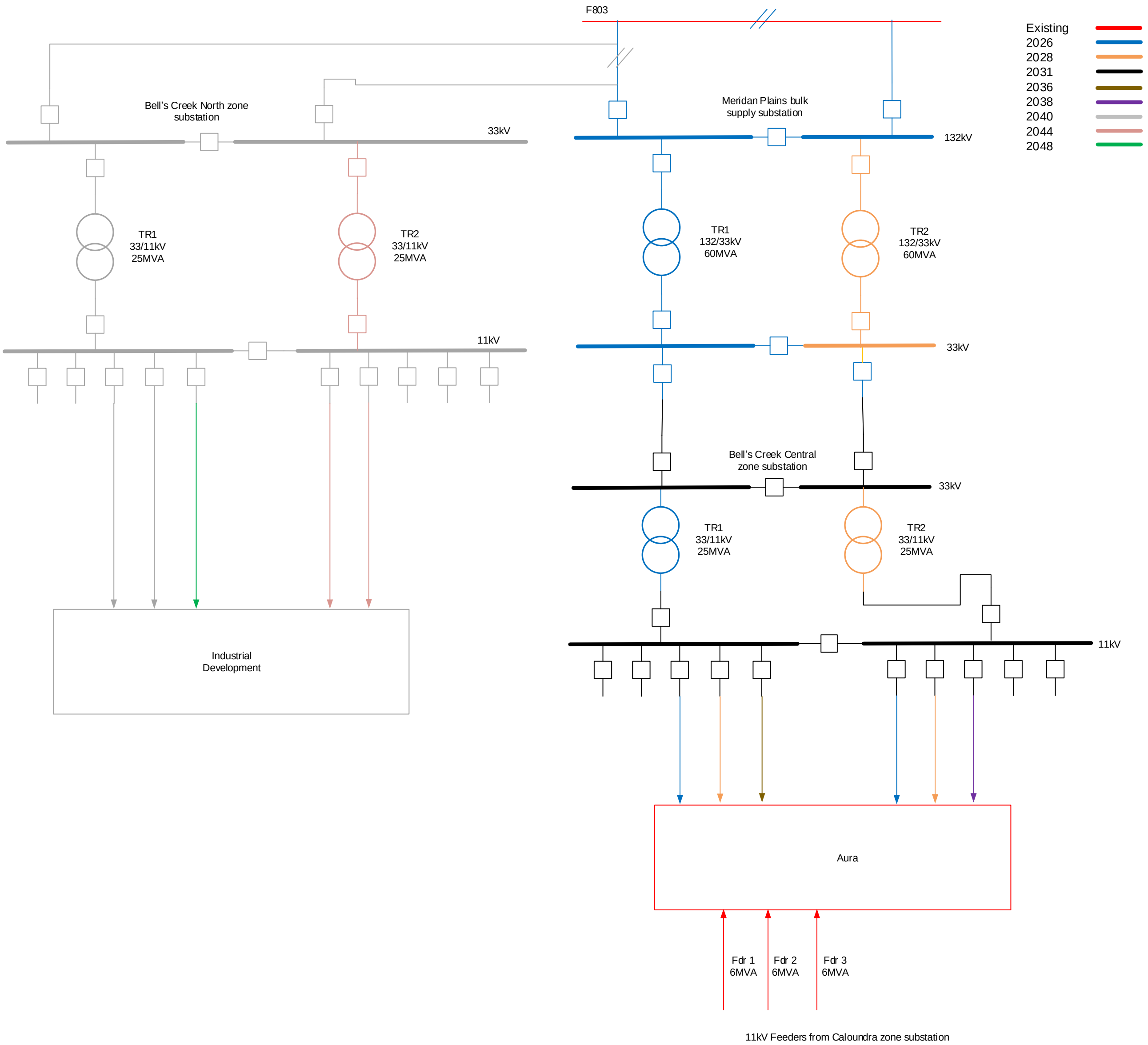


Figure 21: Proposed network arrangement under option 7

Option 8: Supply New Demand with 132kV Feeders (Tee off at Mark Rd East) to Bell's Creek Central Establishment

This option involves establishing a new substation at Bell's Creek Central to supply the Aura subdivision and surrounding area. This option is similar to Option 2.

The works required to implement this option are:

- Establish Bell's Creek Central 132/11kV zone substation in 2026 with the following:
    - single 132/11kV transformer,
    - associated switchgear,
    - 7km of 132kV double circuit line (1km OH, 6km UG) from Mark Rd East;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish the 2nd 132/11kV transformer in 2029 at Bell's Creek North;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.
- Estimated initial capital cost: $62.7 million ± 40% (2026)
- Estimated initial operating cost per annum: $125,599 (2026)

A schematic diagram of the proposed solution is shown in Figure 22 below.

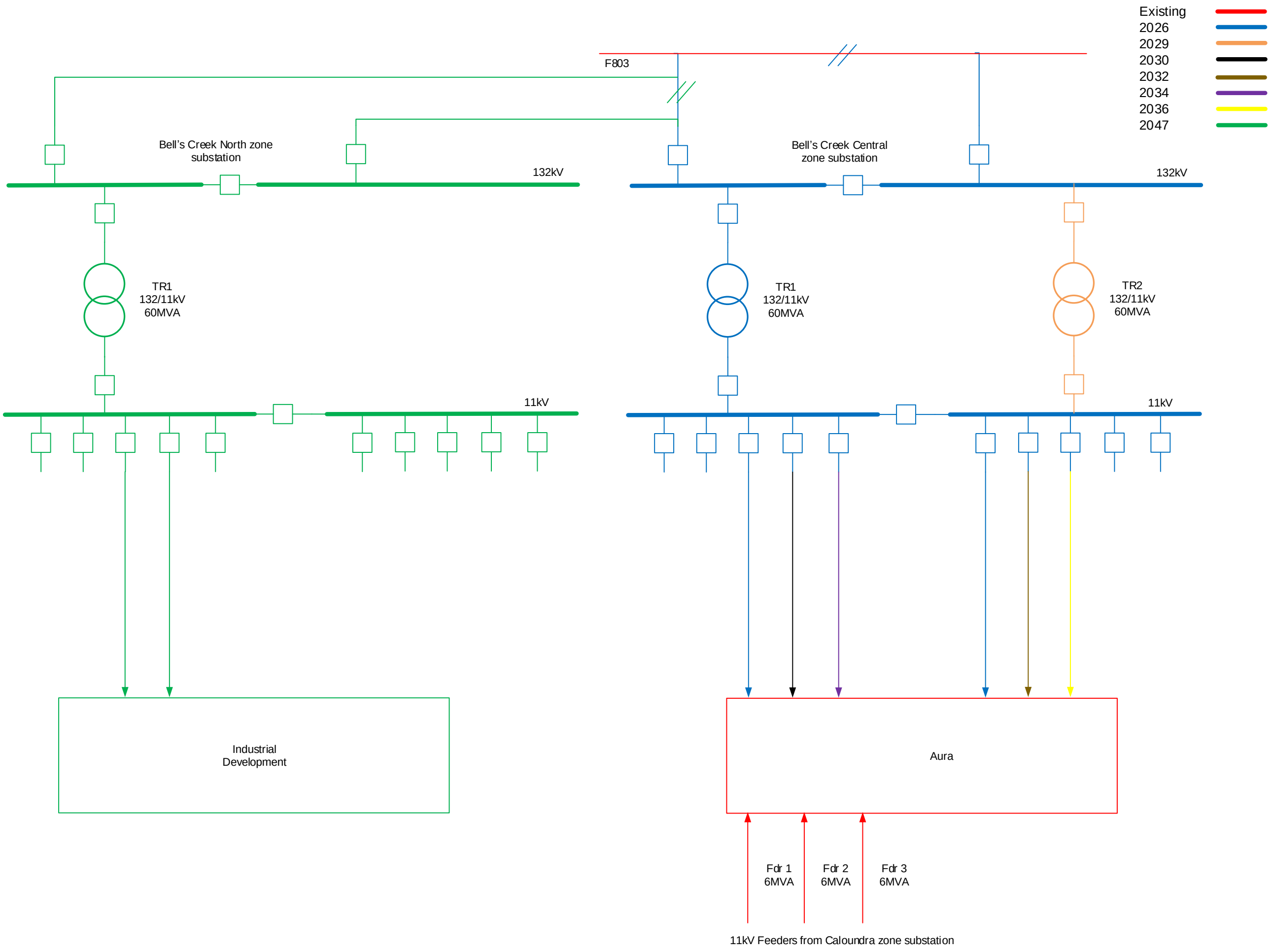


Figure 22: Proposed network arrangement under option 8

Option 9: Supply New Demand with 132kV Feeders from Caloundra Substation to Bell's Creek Central Establishment

This option involves establishing a new 132kV double circuit line from Caloundra Substation and utilising it initially at 11kV to supply the Aura subdivision and surrounding area. This option is similar to Option 1 where the construction of Bell's Creek Central establishment is deferred and constructed when required in 2029.

The works required to implement this option are:

- Establish 9km of 132kV double circuit line (1km OH, 8km UG) from SSCLD in 2026;
- Establish Bell's Creek Central 132/11kV zone substation in 2029 with the following:
  - two 132/11kV transformers,
  - associated switchgear;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.
- Estimated initial capital cost: $50.9 million ± 40% (2026)
- Estimated initial operating cost per annum: $102,683 (2026)

A schematic diagram of the proposed solution is shown in Figure 23 below.

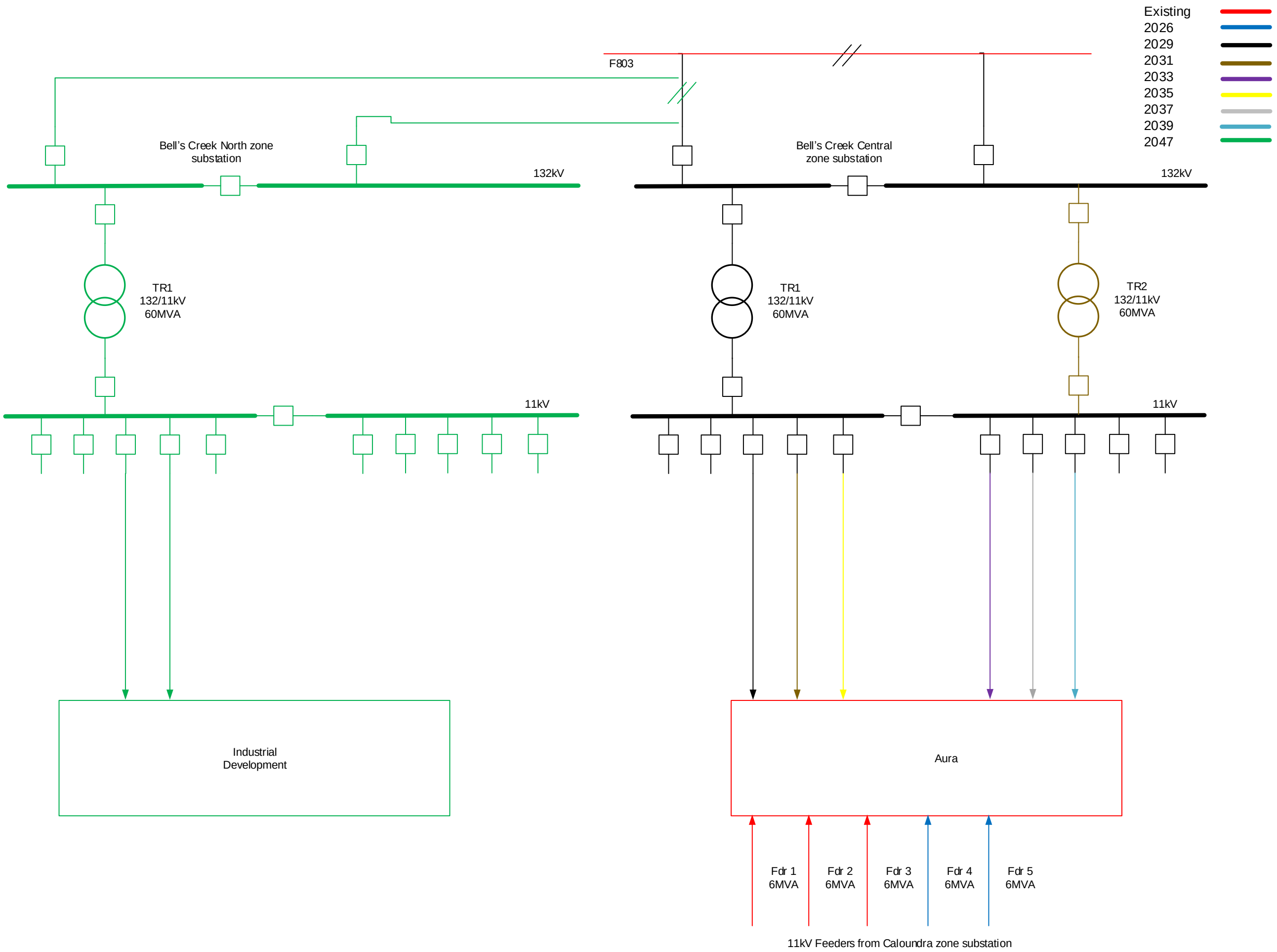


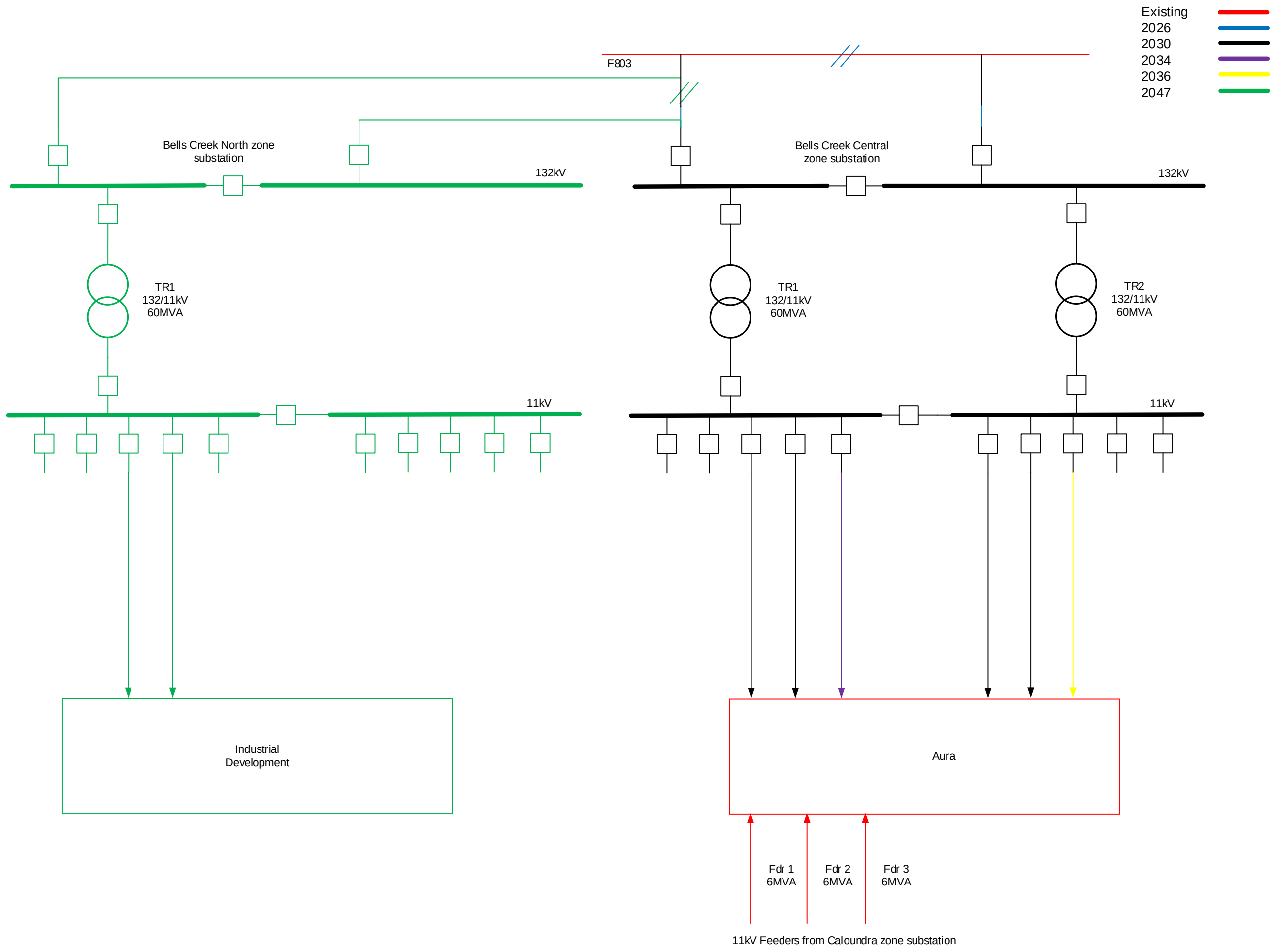
Figure 23: Proposed network arrangement under option 9

Option 10: Contract a 24MW/39.75MWh Battery Energy Storage Solution

This option involves contracting a proponent to provide multiple 24MW/39.75MWh Battery Energy Storage Solution (BESS) totalling 24MW/39.75MWh for an 8-year period to eliminate load at risk in the vicinity of SSCLD from 2022. The BESS will be fully charged and ready to provide peak load relief.

The works required to implement this option are:

- Proponent to install and provide 24MW/39.75MWh battery support across CLD1A, CLD11, CLD18A, CLD29A and the new CLD 11kV feeder from SSCLD to Aura.
    - 2MW/2.3MWh on CLD11 in 2021
    - 22MW/37.45MWH spread across CLD1A, CLD11, CLD18A, CLD29A and the new CLD 11kV in 2027
- Establish 4km of 132kV underground double circuit line and one 11kV feeder to from Caloundra 11kV in 2026;
- Establish a 11kV feeder tie between CLD18A and CLD29A with 132kV feeder but energised at 11kV;
- Establish Bell's Creek Central 132/11kV zone substation in 2030 with the following:
    - 2 x 132/11kV transformer,
    - associated switchgear,
    - 9km of 132kV overhead double circuit line;
- Establish 11kV feeders as required to supply the Aura and Industrial area;
- Establish Bell's Creek North 132/11kV zone substation with a single transformer in 2047 based on continued demand growth.



Existing
2026
2030
2034
2036
2047
F803
Bells Creek North zone substation
132kV
Bells Creek Central zone substation
132kV
TR1
132/11kV
60MVA
TR1
132/11kV
60MVA
TR2
132/11kV
60MVA
11kV
11kV
Industrial Development
Aura
Fdr 1
6MVA
Fdr 2
6MVA
Fdr 3
6MVA
11kV Feeders from Caloundra zone substation