Regulatory Investment Test for Distribution (RIT-D)

Reliability Corrective Action
The Pimpama-Coomera Network Area

Options Screening Report

05/01/2026

energex
Part of Energy Queensland

INTRODUCTION

Purpose

The National Electricity Rules (NER) require that, subject to certain exclusions, distribution network service providers who are looking to address an identified need, by investing in the network, must apply the regulatory investment test for distribution (RIT-D). This Options Screening Report (Report) has been prepared by Energex Limited (Energex) in accordance with the requirements of clause 5.17.4(e) of the NER and seeks information from all interested parties, as listed in clause 5.17.4(a) of the NER, about alternative potential credible options to address the identified need.

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 57,000 kilometres of powerlines and 450,000 power poles, along with associated infrastructure such as major substations and power transformers.

Today, we provide distribution services to more than 1.5 million domestic and business connections, delivering electricity to a population base of around 4 million people.

CONTENTS

1. ASSUMPTIONS AND TECHNICAL CHARACTERISTICS OF THE IDENTIFIED NEED

1.1. Existing supply arrangement

1.1.1. Location

Coomera Bulk Supply Substation (SSCMA) is a 110/33/11kV bulk supply and zone substation with 2 x 80MVA, 110/33kV and 2 x 25MVA, 33/11kV transformers. The zone substation (SSCMA) is directly connected to and supplied from the bulk supply substation and provides electricity supply to approximately 11,990 predominantly residential customers in the Upper Coomera, Coomera, Pimpama, and Willow Vale areas.

Pimpama East Zone Substation (SSPPE) is a 33/11kV substation with 2 x 25MVA transformers supplied from SSCMA BS via 33kV feeders F3641 and F3642. SSPPE provides electricity supply to approximately 14,017 predominantly residential customers in the Pimpama, Coomera, Jacobs Well and Steiglitz areas.

Coomera and Pimpama have been designated as a high to medium density residential zone in the Gold Coast City Plan. Growth data from the 2021 census shows that, from 2011 to 2021, the number of private dwellings in Pimpama grew from 3,957 to 8,499. The area continues to see strong population growth and economic development as there are still pockets of undeveloped land within the area. This is reflected in the significant increase in the load forecast, causing network limitations in the area.

The location where network support and load restoration capability will be measured / referenced is on the 11kV buses at SSPPE Pimpama East and SSCMA Coomera substations. However, alternative options may be located downstream of the reference buses.

1.1.2. Overview of Existing System

Geographic and schematic views of the network area are provided in the following.

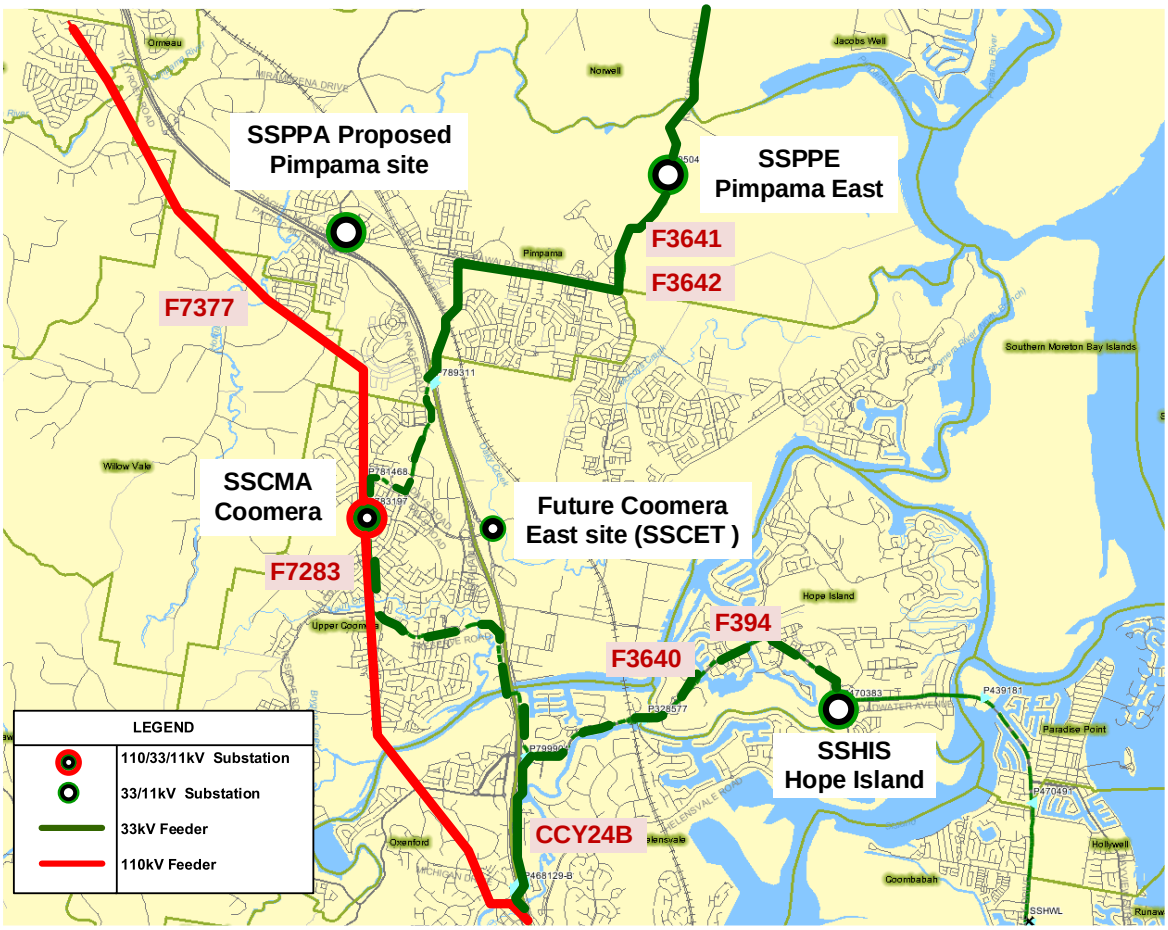


Figure 1: Existing network arrangement (geographic view)

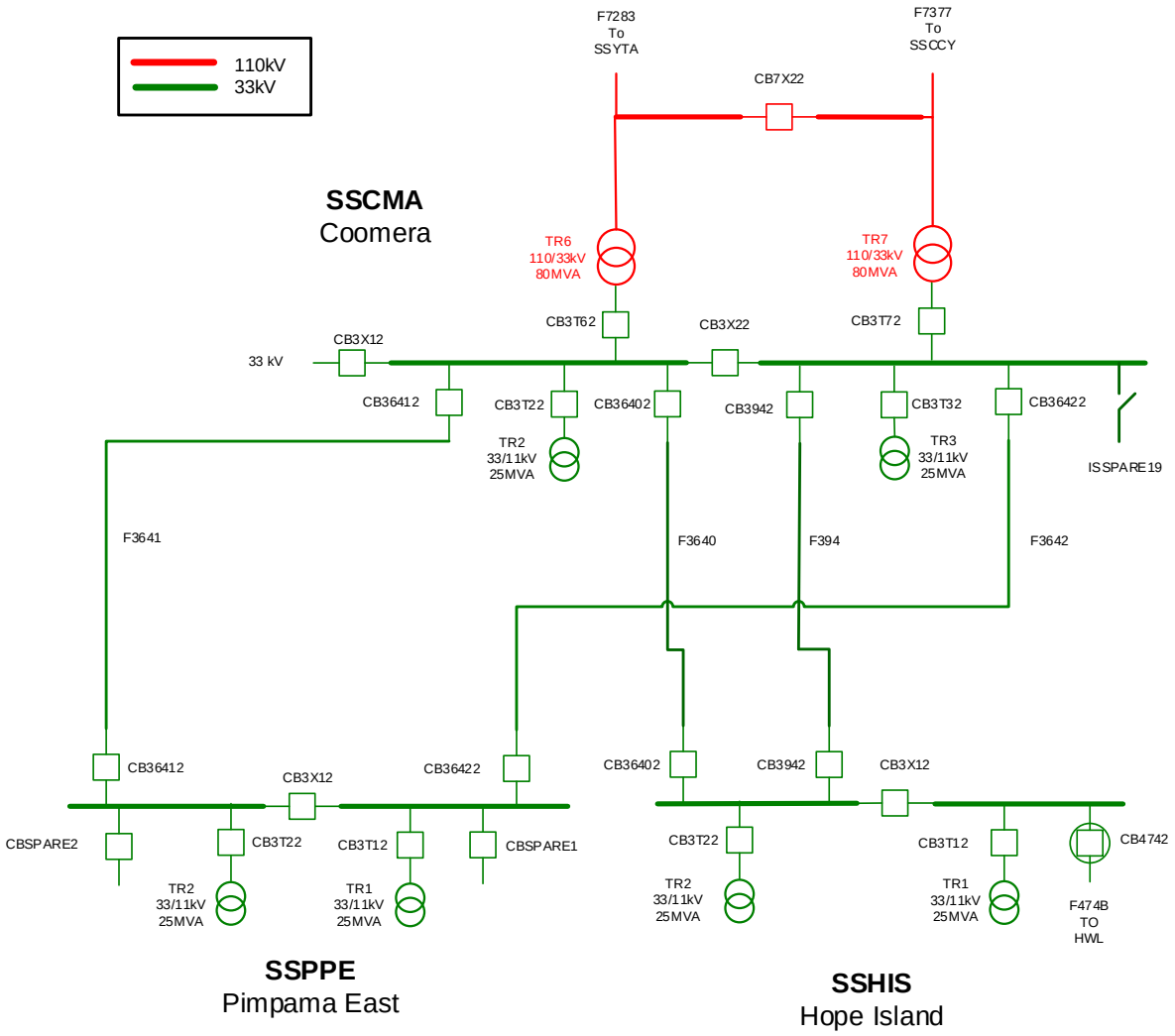


Figure 2: Existing sub transmission network arrangement (schematic view)

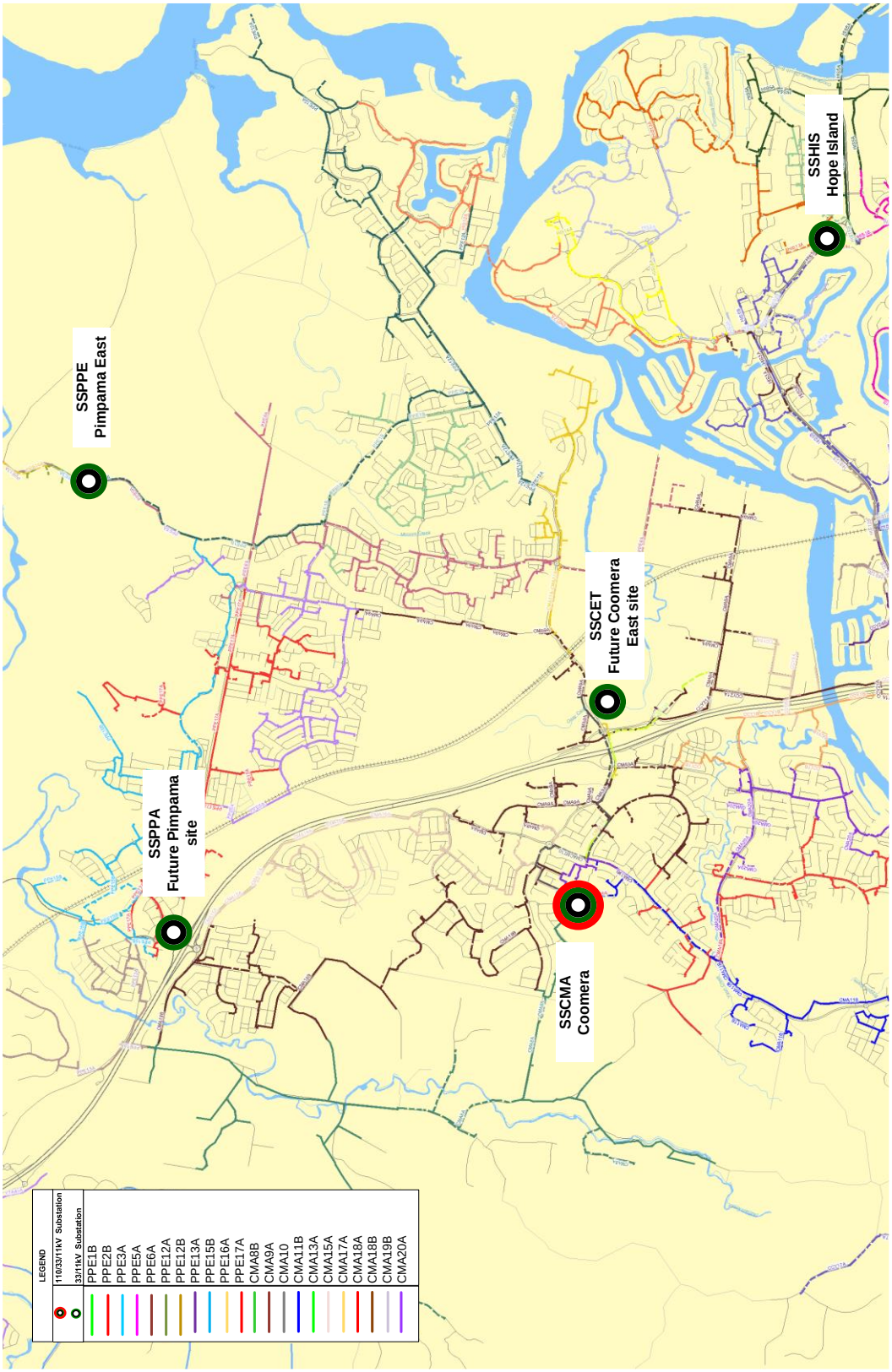


Figure 3: Existing 11kV network arrangement (geographic view)

1.2. Contribution to power system security or reliability

The solution should have a level of redundancy that enables Energex to comply with the safety net targets as required under its Distribution Authority, which has specific outage restoration timeframe targets that Energex is required to achieve. Both SSPPE and SSCMA zone substations are classified as “Urban” for the purposes of the safety net. Details of the safety net targets are shown in

Appendix A – Safety Net Targets.

1.3. Contribution to power system fault levels

The solution must consider the fault level contribution to the network and include any mitigation works that are required due to a change in fault level. The maximum fault level on 33kV and 11kV network should not exceed 25kA and 13.1kA respectively.

1.4. Operating profile

1.4.1. Peak load profile

The actual load and load duration curves for SSPPE and SSCMA for the 2024/25 period are shown in Figure 4 to Figure 7. Generally, the load peaks during the summer period.

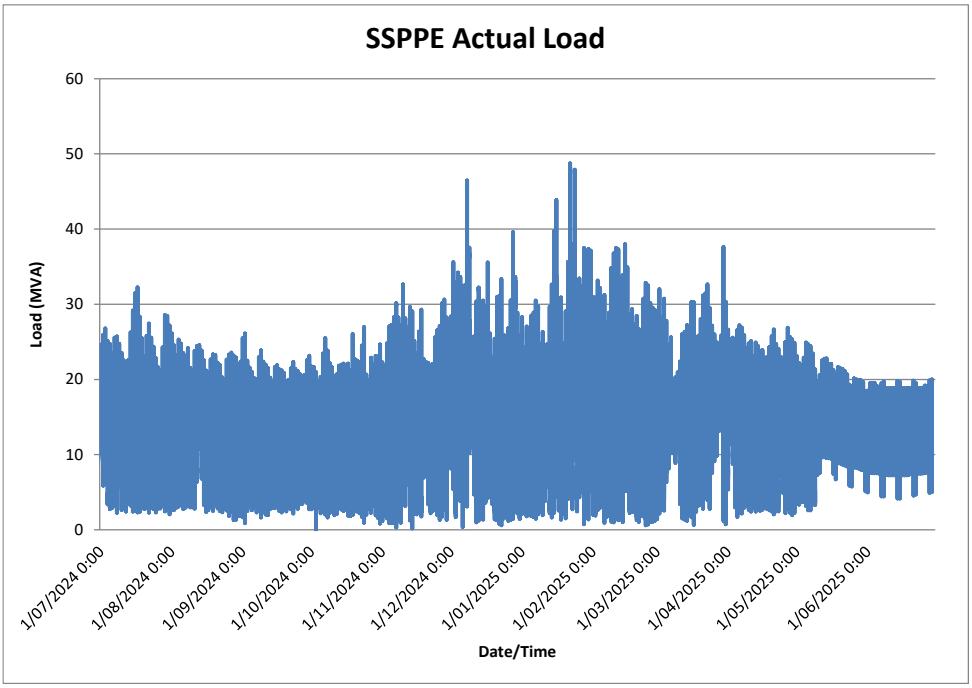


Figure 4: Substation load curve – SSPPE

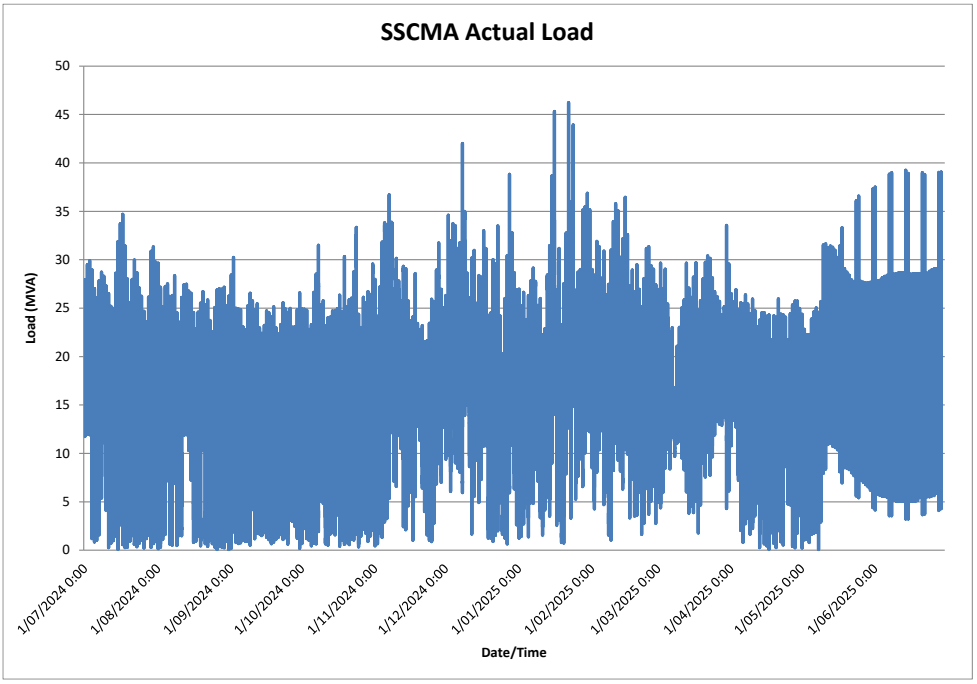


Figure 5: Substation load curve – SSCMA

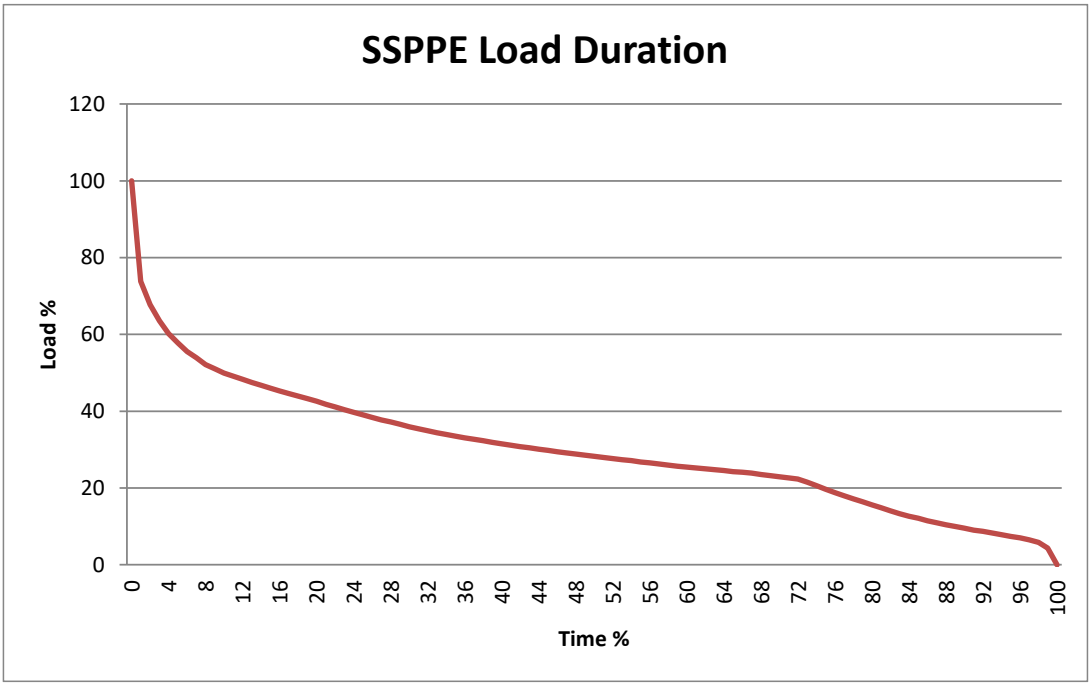


Figure 6: Substation load duration curve – SSPPE

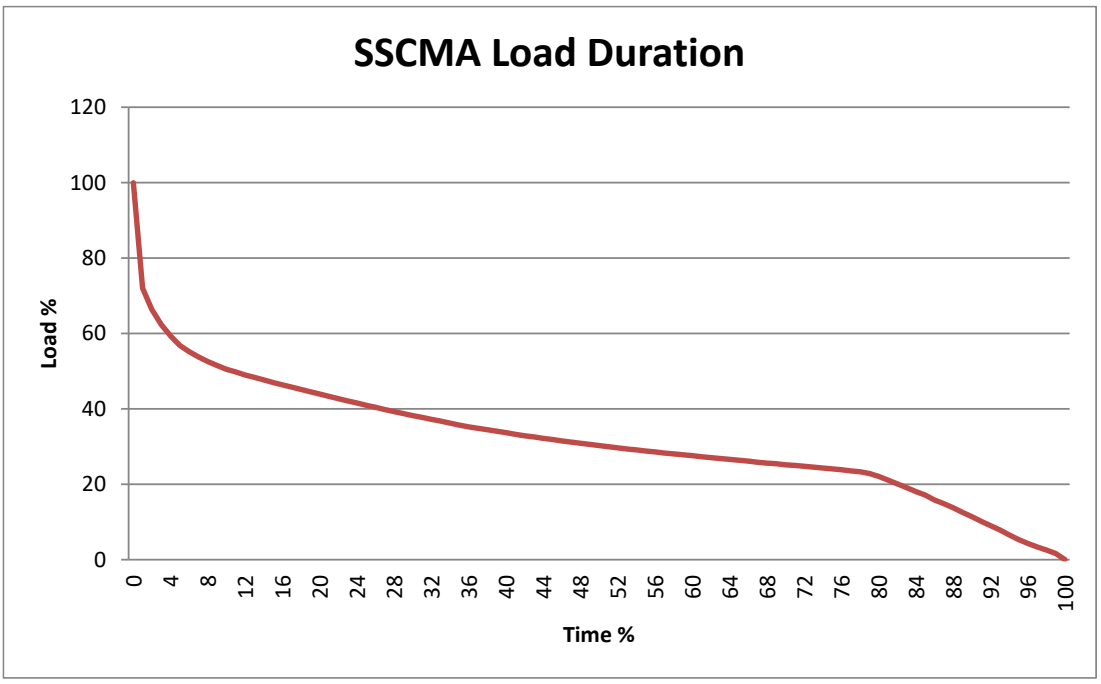


Figure 7: Substation load duration curve – SSCMA

The daily load profile for the peak day during Summer is illustrated below in Figure 8 and Figure 9. It can be noted that the Summer peak loads are historically experienced in late afternoon and evening.

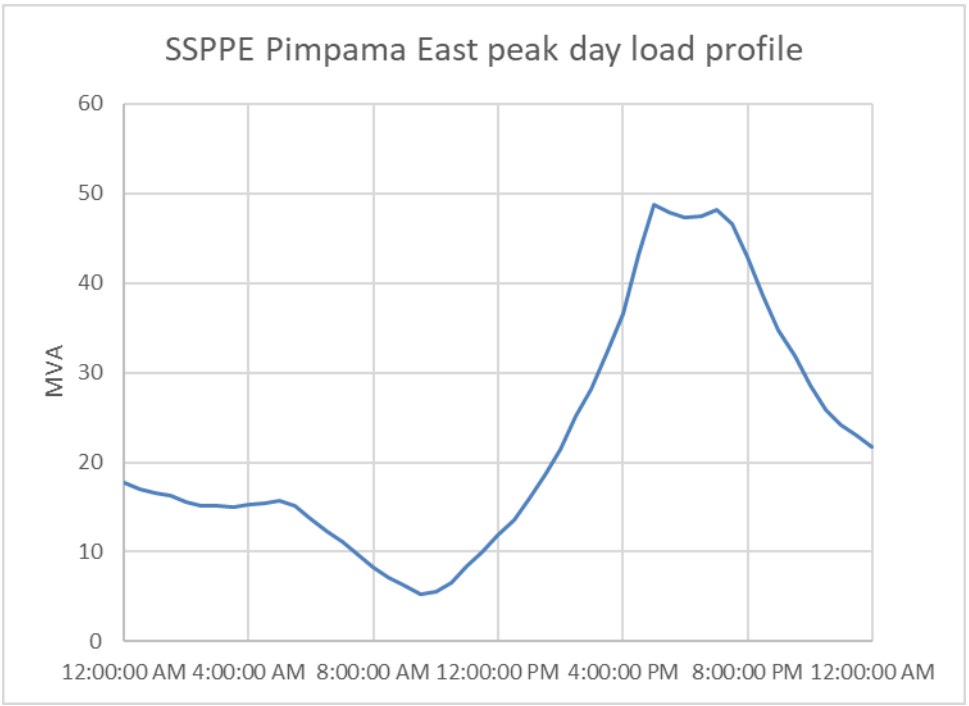


Figure 8: Pimpama East zone substation load profile (Peak Day)

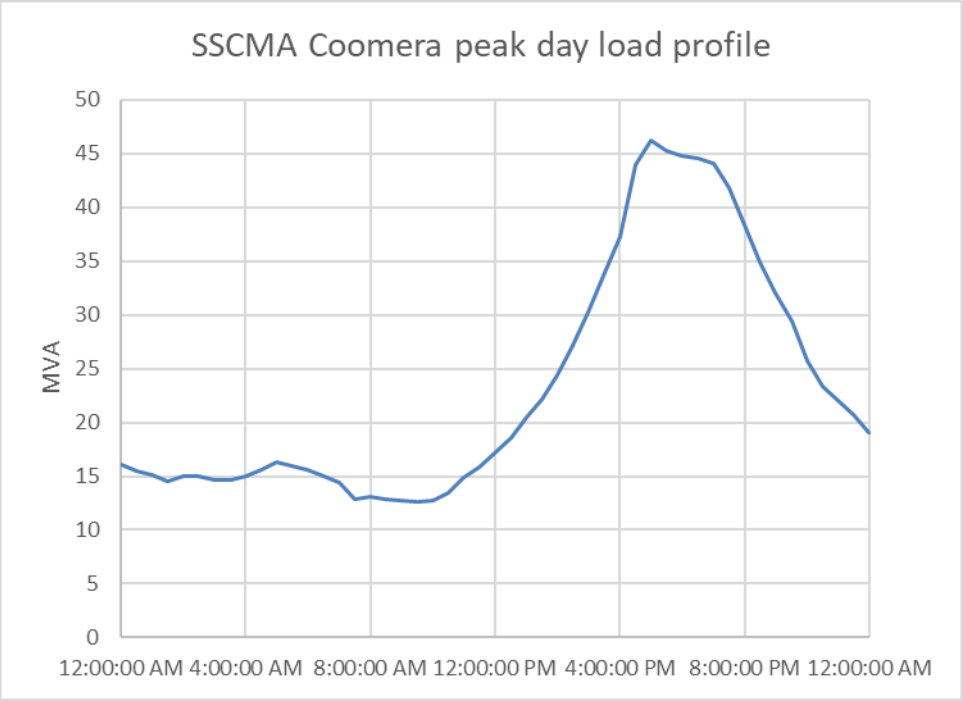


Figure 9: Coomera zone substation load profile (Peak Day)

1.4.2. Minimum demand profile

The uptake of solar PV in the residential, commercial and industrial sectors has created limitations on the Energex network during minimum demand periods. The impacts of minimum demand include capacity limitation due to reverse power flow on substation transformers, voltage regulation, power quality and protection issues, etc.

The forecast minimum demand profile at SSPPE and SSCMA with the impact of increasing number of solar PV systems is shown in Figure 10 and Figure 11.

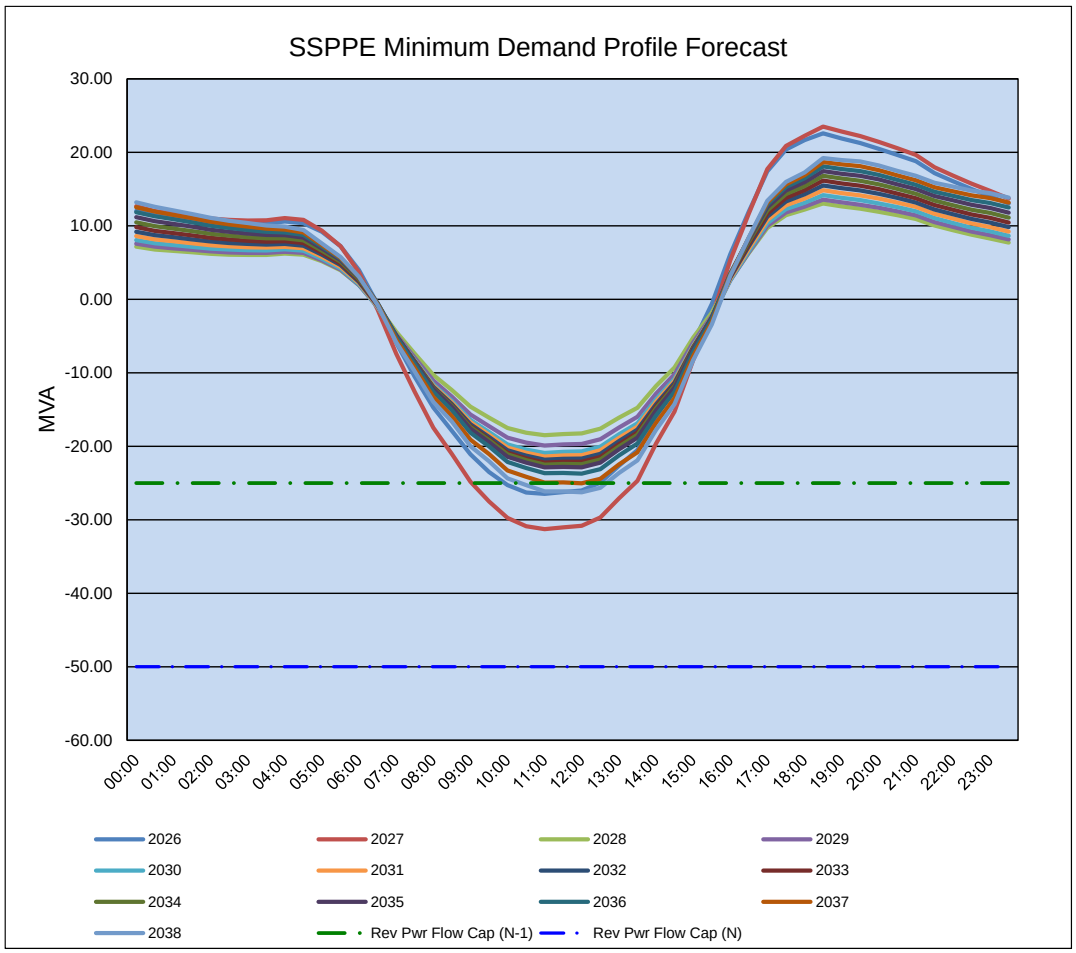


Figure 10: Minimum demand profile – SSPPE

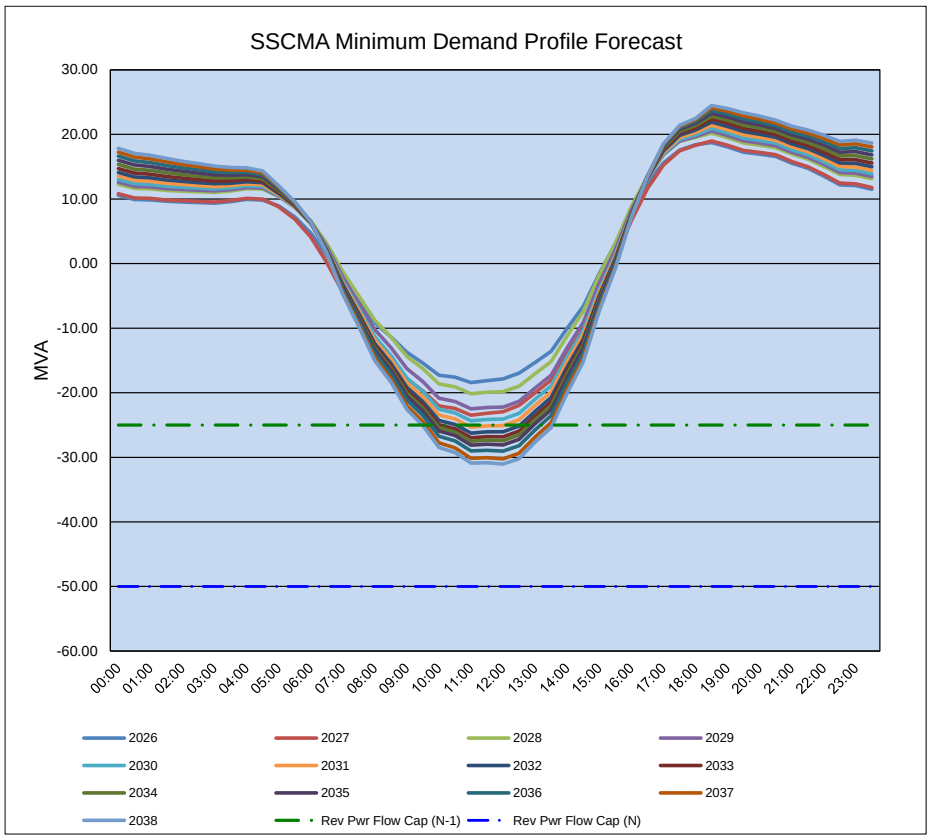


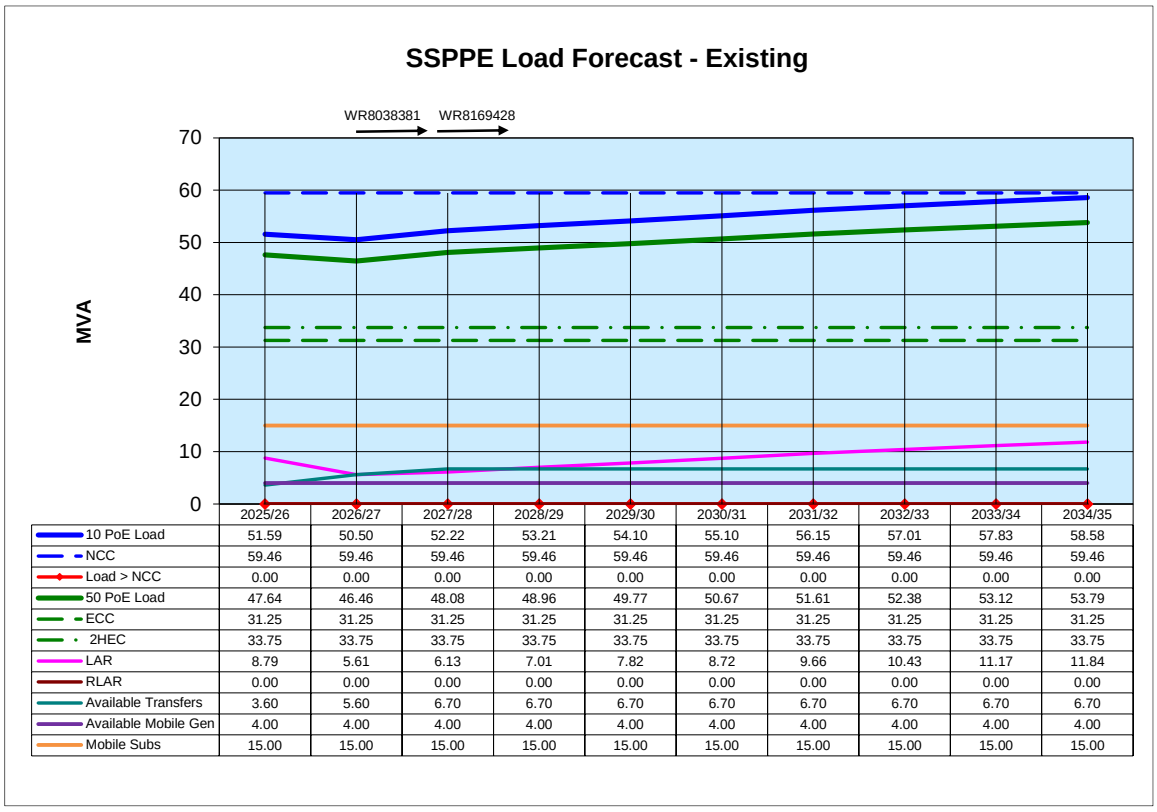
Figure 11: Minimum demand profile – SSCMA

1.5. Size of Load Reduction Relating to Existing Supply Forecast

1.5.1. Substation load forecast and capacity

SSPPE - Pimpama East Zone Substation

SSPPE is equipped with 2 x 25MVA 33/11kV transformers. The substation capacity is limited by transformers, providing a Normal Cyclic Capacity of 59.46MVA. The 10 year 10 PoE and 50 PoE load forecasts, and the existing Normal Cyclic Capacity (NCC), Emergency Cyclic Capacity (ECC), Two Hour Emergency Capacity (2HEC), Residual Load at Risk (RLAR), available transfers and available mobile equipment, are shown in Figure 12.



	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
10 PoE Load	51.59	50.50	52.22	53.21	54.10	55.10	56.15	57.01	57.83	58.58
NCC	59.46	59.46	59.46	59.46	59.46	59.46	59.46	59.46	59.46	59.46
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	47.64	46.46	48.08	48.96	49.77	50.67	51.61	52.38	53.12	53.79
ECC	31.25	31.25	31.25	31.25	31.25	31.25	31.25	31.25	31.25	31.25
2HEC	33.75	33.75	33.75	33.75	33.75	33.75	33.75	33.75	33.75	33.75
LAR	8.79	5.61	6.13	7.01	7.82	8.72	9.66	10.43	11.17	11.84
RLAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Available Transfers	3.60	5.60	6.70	6.70	6.70	6.70	6.70	6.70	6.70	6.70
Available Mobile Gen	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Mobile Subs	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

Figure 12: Substation load forecast - SSPPE (existing network)

As outlined above, during a contingency event of loss of the 33/11kV transformer at SSPPE, there is a forecast load at risk of 8.79MVA in summer 2025/26.

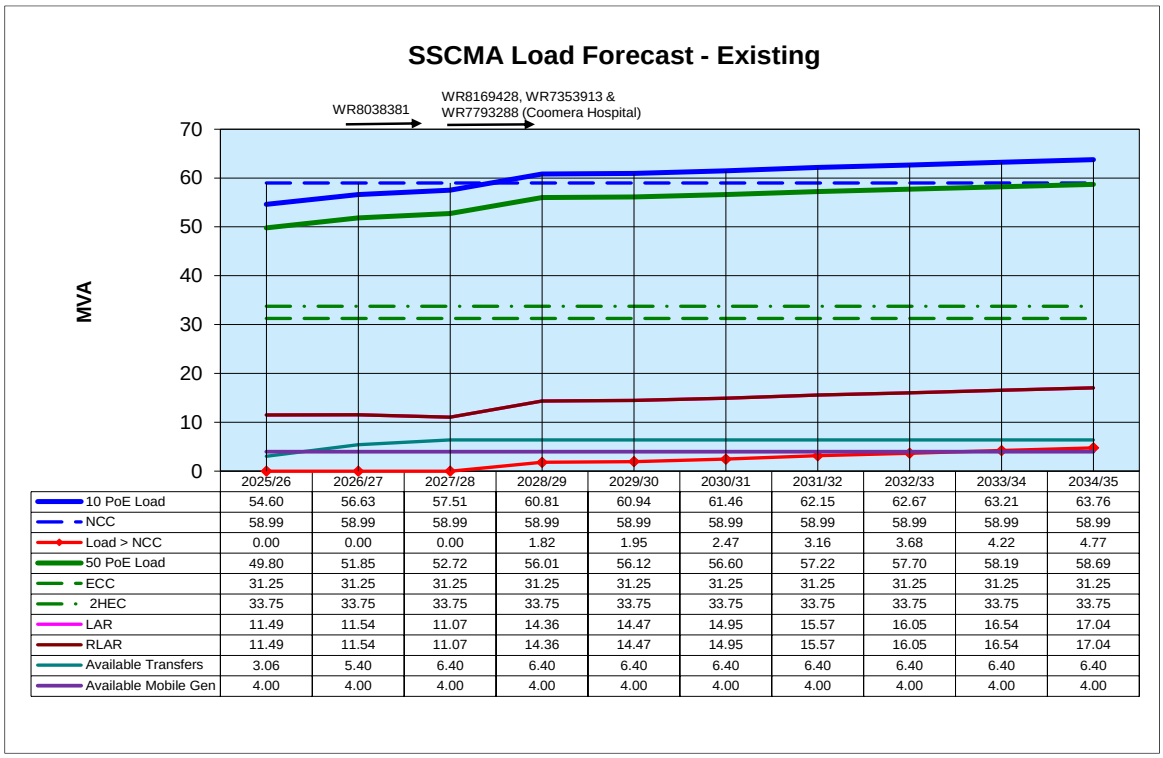
The forecast load also exceeds the 2HEC of the remaining transformer, however there is currently a plant overload protection software (POPS) scheme to automatically reduce the substation load to below the 2HEC to avoid overloading of the remaining transformer.

Energex will establish additional 11kV feeder ties between SSCMA & SSPPE which will increase the transfer capacity between the two substations by approximately 3.1MVA by June 2027.

SSPPE has a mobile substation connection kiosk, however the time required to deploy and connect the mobile substation will be in breach of the Safety Net application guidelines.

SSCMA - Coomera Zone Substation

SSCMA is equipped with 2 x 25MVA 33/11kV transformers. The substation capacity is limited by transformers, providing a Normal Cyclic Capacity of 58.99MVA. The 10 year 10 PoE and 50 PoE load forecasts, and the existing Normal Cyclic Capacity (NCC), Emergency Cyclic Capacity (ECC), Two Hour Emergency Capacity (2HEC), Residual Load at Risk (RLAR), available transfers and available mobile equipment, are shown in Figure 13.



	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
10 PoE Load	54.60	56.63	57.51	60.81	60.94	61.46	62.15	62.67	63.21	63.76
NCC	58.99	58.99	58.99	58.99	58.99	58.99	58.99	58.99	58.99	58.99
Load > NCC	0.00	0.00	0.00	1.82	1.95	2.47	3.16	3.68	4.22	4.77
50 PoE Load	49.80	51.85	52.72	56.01	56.12	56.60	57.22	57.70	58.19	58.69
ECC	31.25	31.25	31.25	31.25	31.25	31.25	31.25	31.25	31.25	31.25
2HEC	33.75	33.75	33.75	33.75	33.75	33.75	33.75	33.75	33.75	33.75
LAR	11.49	11.54	11.07	14.36	14.47	14.95	15.57	16.05	16.54	17.04
RLAR	11.49	11.54	11.07	14.36	14.47	14.95	15.57	16.05	16.54	17.04
Available Transfers	3.06	5.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40	6.40
Available Mobile Gen	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

Figure 13: Substation load forecast - SSCMA (existing network)

As outlined above, during a contingency event of loss of a 33/11kV transformer at SSCMA, there is a forecast load at risk of 11.49MVA during summer 2025/26 and a residual load at risk of 11.49MVA after all load transfers and deployment of mobile equipment in summer 2025/26. *(Note: SSCMA has no mobile substation connection kiosk.)*

The 10 PoE load at SSCMA is forecast to exceed NCC of the transformers in summer 2028/29.

The forecast load also exceeds the 2HEC of the remaining transformer, however there is currently a POPS scheme to automatically reduce the substation load to below the 2HEC to avoid overloading of the remaining transformer.

Size of Load Reduction or Additional Supply

As described above, the load reduction required at SSPPE and SSCMA is significant; Please refer to the Identified Need details presented in section 2 for the load reduction requirements for this RIT-D.

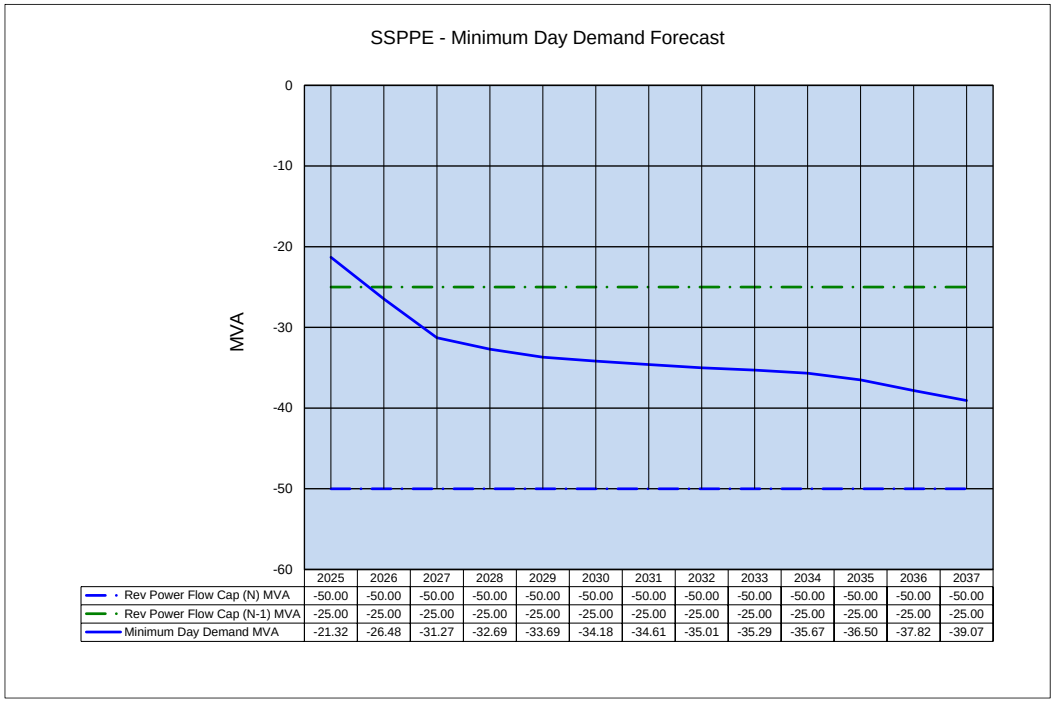
1.5.2. Solar PV forecast

Rooftop PV is driving an increasingly rapid change in load on the network from day to night. The rapid uptake of solar PV has changed the way power travels through the network, from a purely one-way to bi-directional energy flow.

SSPPE and SSCMA have 44MVA and 46MVA respectively of rooftop PV solar inverter capacity connected to their networks.

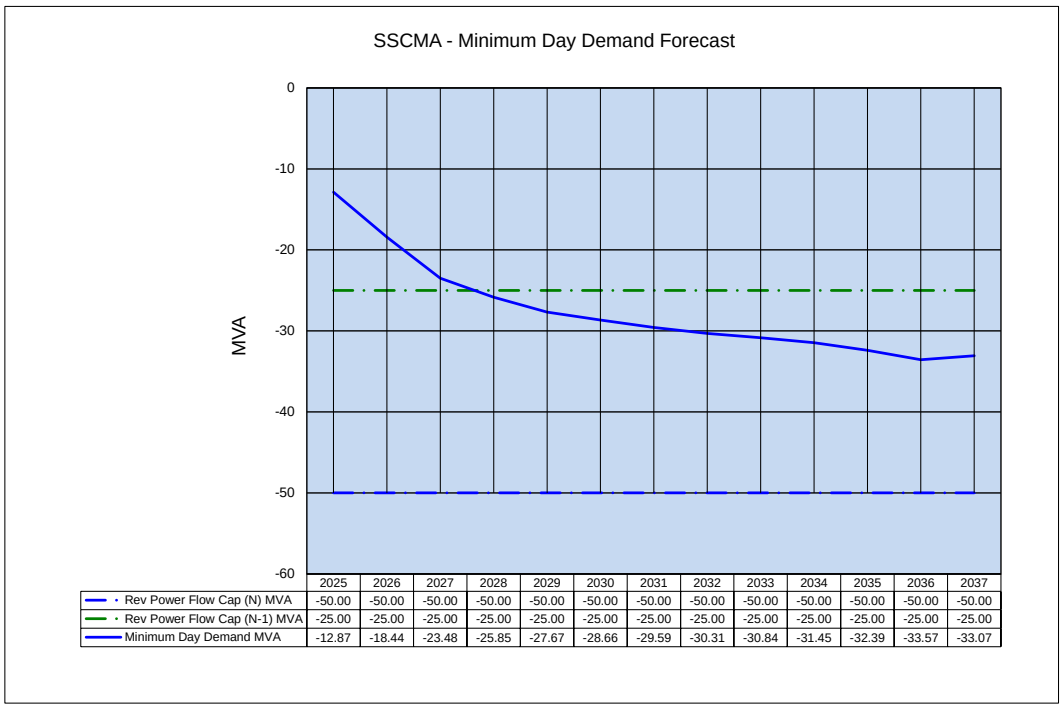
1.5.3. Minimum demand forecast

The minimum demand forecast at SSPPE and SSCMA with the aggregated impact of connected solar PV systems are decreasing as shown in Figure 14 and Figure 15. The applicable reverse power flow capacity is the same as the nameplate rating of the transformer with all available cooling modes.



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Rev Power Flow Cap (N) MVA	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00
Rev Power Flow Cap (N-1) MVA	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00
Minimum Day Demand MVA	-21.32	-26.48	-31.27	-32.69	-33.69	-34.18	-34.61	-35.01	-35.29	-35.67	-36.50	-37.82	-39.07

Figure 14: Minimum day demand forecast – SSPPE



	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Rev Power Flow Cap (N) MVA	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00	-50.00
Rev Power Flow Cap (N-1) MVA	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00	-25.00
Minimum Day Demand MVA	-12.87	-18.44	-23.48	-25.85	-27.67	-28.66	-29.59	-30.31	-30.84	-31.45	-32.39	-33.57	-33.07

Figure 15: Minimum day demand forecast – SSCMA

As outlined above there is a reverse power flow capacity limitation during contingency conditions at SSPPE from 2026 and at SSCMA from 2028 onwards.

2. IDENTIFIED NEED

The identified need is for reliability corrective action to ensure that reliability of supply and service obligations are maintained to customers in the Pimpama-Coomera network area. This is due to significant increase in load in this area, such that reasonable supply to customers cannot be maintained, in particular under N-1 network contingency scenarios. Under applicable regulatory instruments, Energex is required to connect new customers and maintain the reliability of supply to these customers (see below). To ensure that Energex can continue to meet these requirements, reliability corrective action is required. Energex seeks to address the identified need by 2027 which is estimated to be the earliest date that the network option could be implemented (see section 3.1). Table 1 and Table 2 specifies the demand reduction (MVA) and energy/time requirement (estimated MWh & hrs respectively) by year based on the earliest and most cost-effective network option identified to date. If this does not occur, Energex estimates the probability of failure to comply with regulatory requirements is deemed to have reached unacceptably high levels.

		Yearly (estimate)		Peak Day (estimate)	
Year	**Max Demand Reduction (MVA)**	**Energy Reduction (MWh)**	**Number of hours**	**Energy Reduction (MWh)**	**Number of hours**
2027/28	6.2	27.5	8	16	4
2028/29	7.0	34	8.5	19.3	4
2029/30	7.8	40.8	9.5	22.4	4
2030/31	8.7	49.3	10.5	25.8	4
2031/32	9.7	58.5	11	29.4	4
2032/33	10.4	66.6	12	32.4	4
2033/24	11.2	74.9	13.5	35.2	4.5
2034/35	11.8	83.4	15	38.1	4.5

Table 1: Load Reduction Requirement By Year At SSPPE

		Yearly (estimate)		Peak Day (estimate)	
Year	**Max Demand Reduction (MVA)**	**Energy Reduction (MWh)**	**Number of hours**	**Energy Reduction (MWh)**	**Number of hours**
2027/28	3.4	33.4	6	12.8	1
2028/29	8.0	110.4	30.5	32	1.5
2029/30	8.0	112.8	31.5	32	1.5
2030/31	8.0	126	36.5	32.7	1.5
2031/32	8.0	143.5	41.5	33.5	2
2032/33	8.0	160.6	48	34.4	2
2033/24	8.0	180.3	54.5	35.3	2
2034/35	8.0	201.5	59	36	2

Table 2: Load Reduction Requirement By Year At SSCMA

Investment in Energex's network is required to continue to meet the following service standards and regulatory requirements, and if this did not occur, it would be a serious risk to Energex of breaching the following:

- *National Energy Retail Law (Queensland)* – Under Part 3, Division 2, Energex has an obligation to provide customers connection service for the premises of a customer who requests those services to be connected to the distribution system.
- Energex's Distribution Authority issued under the *Electricity Act 1994* (Qld) – Under Clause 10, Energex is required to design, plan and operate its network to meet the service safety net, which aims to mitigate the risk of low probability-high consequence network outages to avoid unexpected customer hardship and/or significant community or economic disruption. The safety net has specific outage restoration timeframe targets that Energex is required to achieve. Details of the safety net targets are shown in

- Appendix A – Safety Net Targets.

As described above, there is underlying customer load at risk (i.e. larger & longer customer outage scenarios) that would remain until the identified need is resolved by a credible option. Options that could be implemented promptly would have increased customer reliability benefits (compared to options that took longer to implement) which will be taken into account during the cost-benefit analysis of all credible options.

2.1. Associated Relevant Annual Deferred Argumentation Charge

A present value analysis of the costs associated with the lowest cost potential credible option show that there is a saving of approximately $0.98 million for each year the proposed augmentation cost is deferred.

3. POTENTIAL CREDIBLE OPTIONS

3.1. Credible Options Identified

Energex has considered all options that could reasonably be classified as a credible option without bias to energy source, technology, ownership and whether it is a network option, a non-network option or a SAPS option.

Energex has identified the below 3 potential credible options that would address the identified need. All of these are network options. Additionally, possible non-network or SAPS option/s may be able to address the identified need, as described in section 3.1.4.

3.1.1. Option A: Establish new 1 x 25MVA 33/11kV Pimpama Zone Substation (SSPPA)

This option would involve:

Establish a new 1 x 25MVA 33/11kV zone substation consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11kV protection panels, and associate plant, 1 x 25MVA 33/11kV transformer, cut in and out of existing 33kV feeder F3642 with a mix of 1.9kms of UG and 1.6kms of OH, establish new 4 x 11kV feeders from the new substation and reconfigure existing 11kV feeders at SSPPE and SSCMA by 2027.

Future Stage:

- Establishing 2nd 25MVA 33/11kV transformer, connected to the existing 11kV bus at SSPPA by 2032.
- Establishing a 2nd module and associated switchgear at SSPPA, consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11 kV protection panels, and associated plant, establish new 33kV & 11kV tie feeders between both modules and reconfigure existing 11kV feeders at SSPPA by 2037.

Figure 16 and Figure 17 provide geographic and schematic diagrams for Option A.

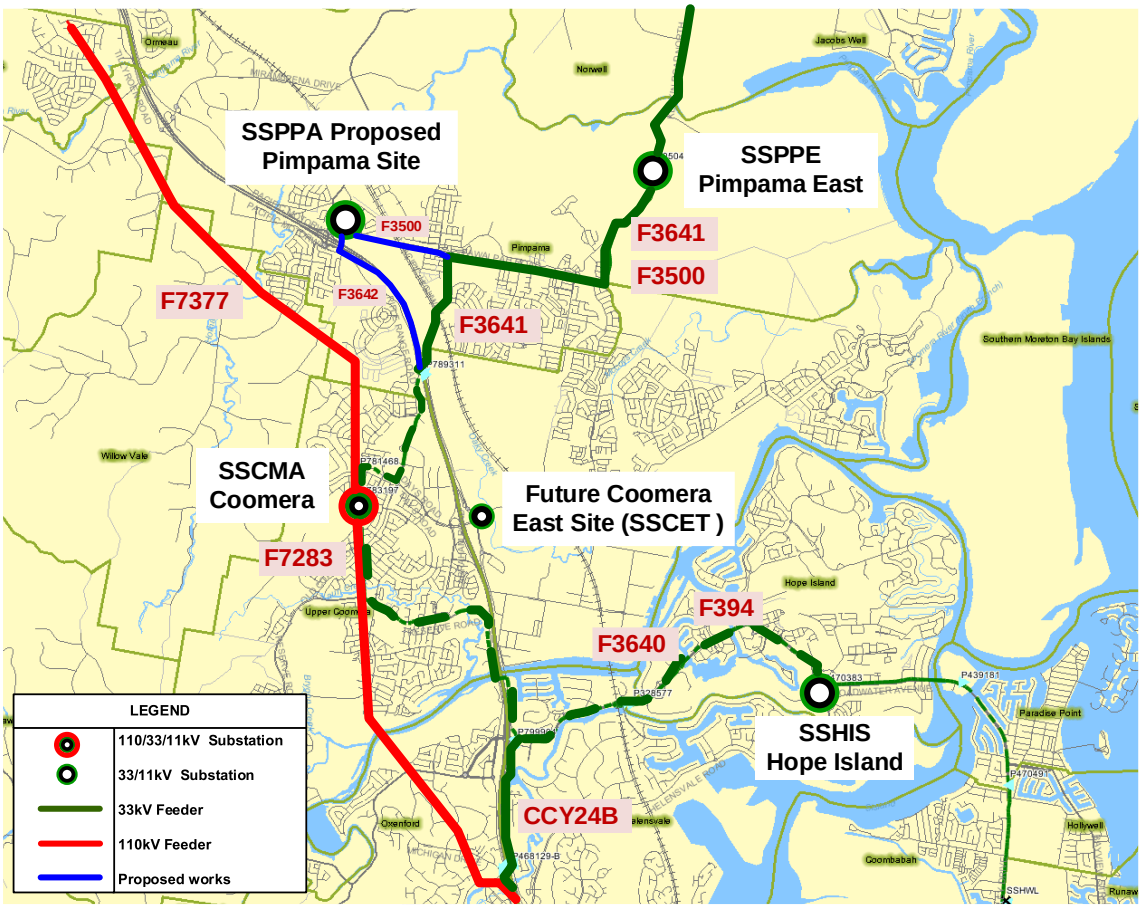


Figure 16: Proposed network arrangement - option A (geographic view)

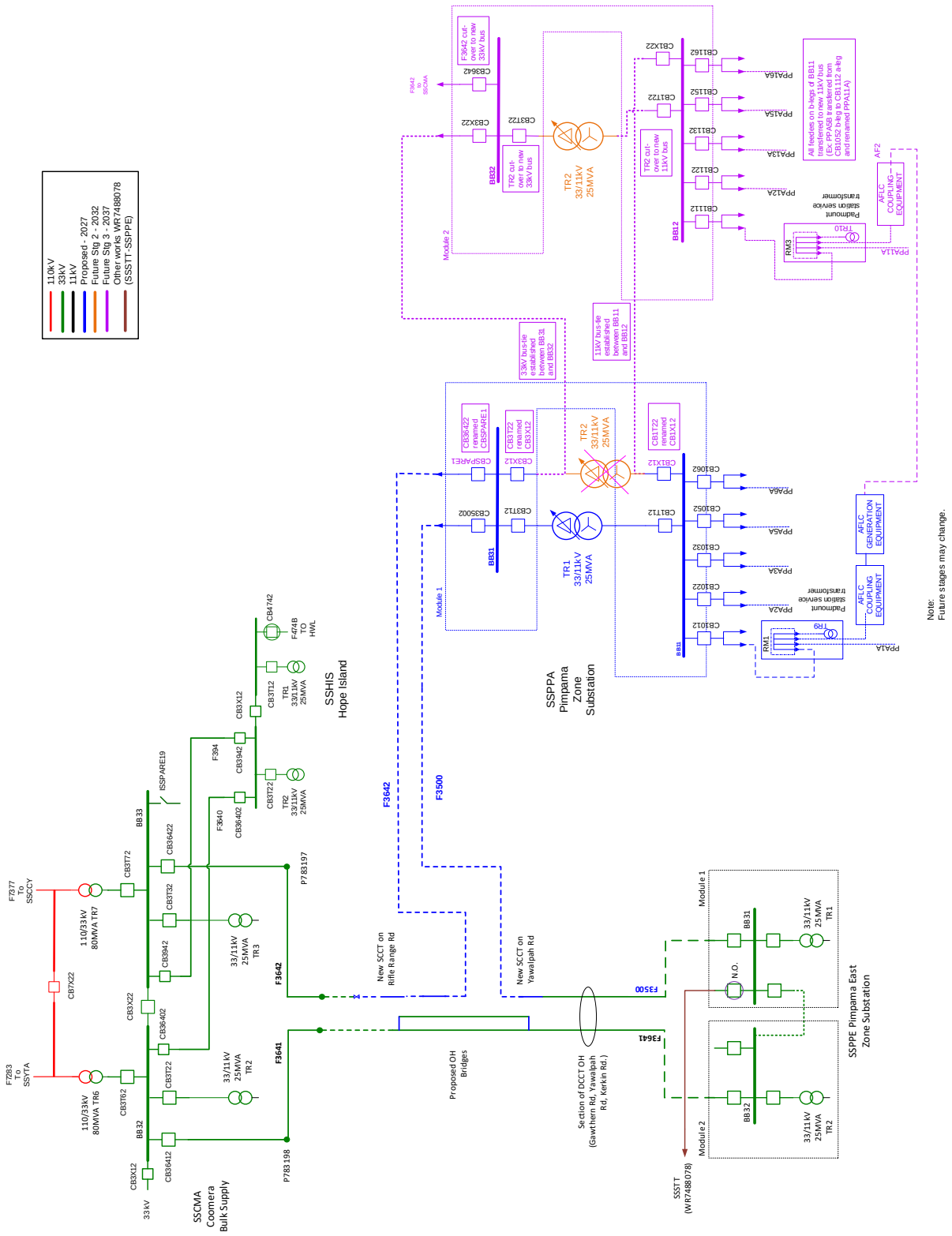


Figure 17: Proposed network arrangement - option A (schematic view)

This option is commercially and technically feasible, can be implemented in the timeframe identified and would address the identified need by providing reliable supply and additional capacity to the Pimpama-Coomera area, which enables Energex to connect new customers to the distribution network and contribute to the reliability requirements stipulated in Energex's Distribution Authority.

The estimated initial capital cost of this option would be $27,429,000. The estimated initial operating costs of this option would be $33,238 per annum. The estimated commissioning date of this option would be 2027.

The estimated construction timetable[1] is:

- Construction start: 2026
- Commissioning: 2027

The estimated costs comprise the following components:

- financial costs incurred in constructing or providing the credible option (including early engagement on the potential connection requirements and costs of each option) - estimated at $27,429,000 per annum.
- operating and maintenance costs - estimated at $33,238 per annum.
- costs of complying with relevant laws, regulations and administrative requirements – included in the above ; and
- costs unique to asset replacement projects or programs – N/A.

There are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline of this option. This is described further in section 4.

3.1.2. Option B: Establish new 1 x 25MVA 33/11kV Coomera East Zone Substation (SSCET)

This option would involve:

Establish a new 1 x 25MVA 33/11kV zone substation at Coomera East (SSCET), consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11kV protection panels, and associated plant, tee-off existing 33kV feeders F3642 & F394 with a mix of UG and OH, establish new 4 x 11kV feeders from the new substation and reconfigure existing 11kV feeders at SSPPE and SSCMA by 2027.

Future Stage:

- Establish 2nd 25MVA 33/11kV transformer, connected to existing 11kV bus at SSCET by 2032.
- Establishing a 2nd module and associated switchgear at SSCET, consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11 kV protection panels, and

[1] Timings shown in this report are indicative and depend on the completion of the RIT-D process.

associated plant, establish new 33kV & 11kV tie feeders between both modules and reconfigure existing 11kV feeders at SSCET by 2037.

Figure 18 and Figure 19 provide geographic and schematic diagrams for Option B.

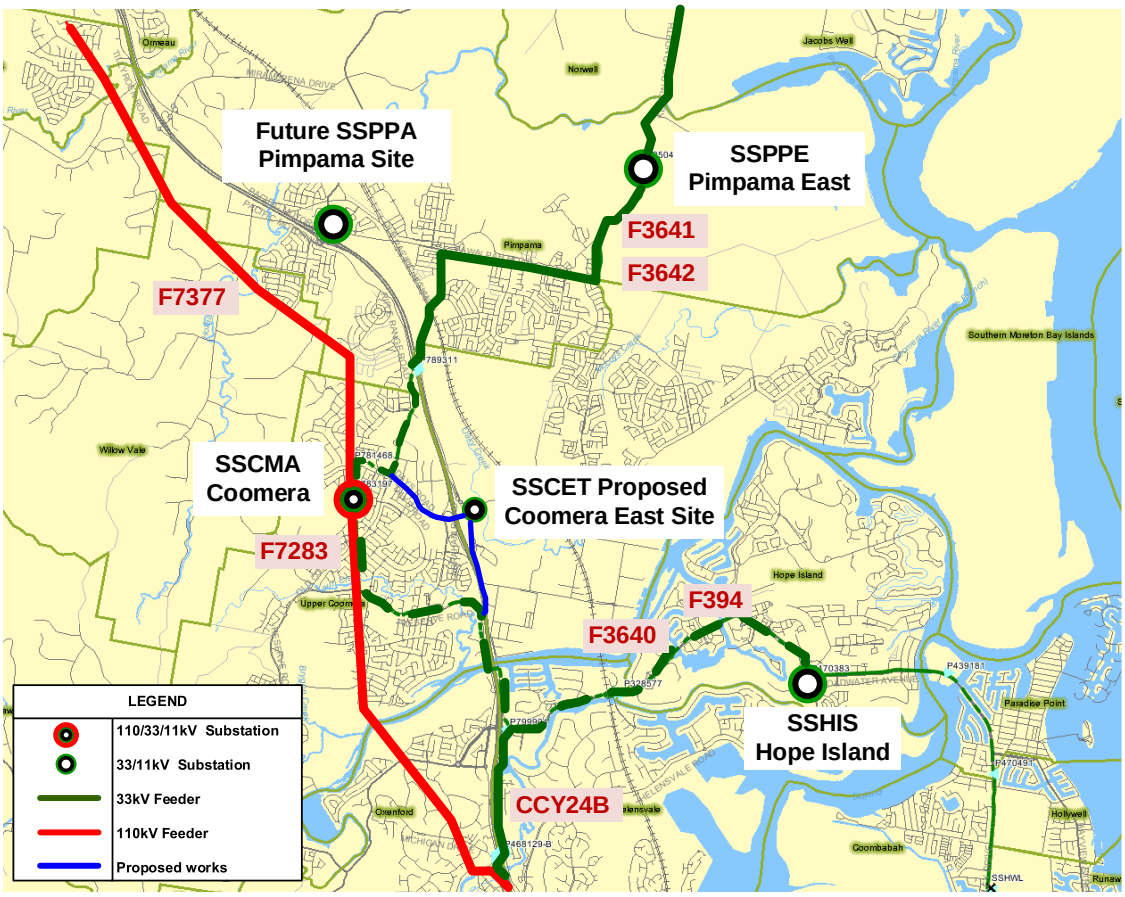


Figure 18: Proposed network arrangement - option B (geographic view)

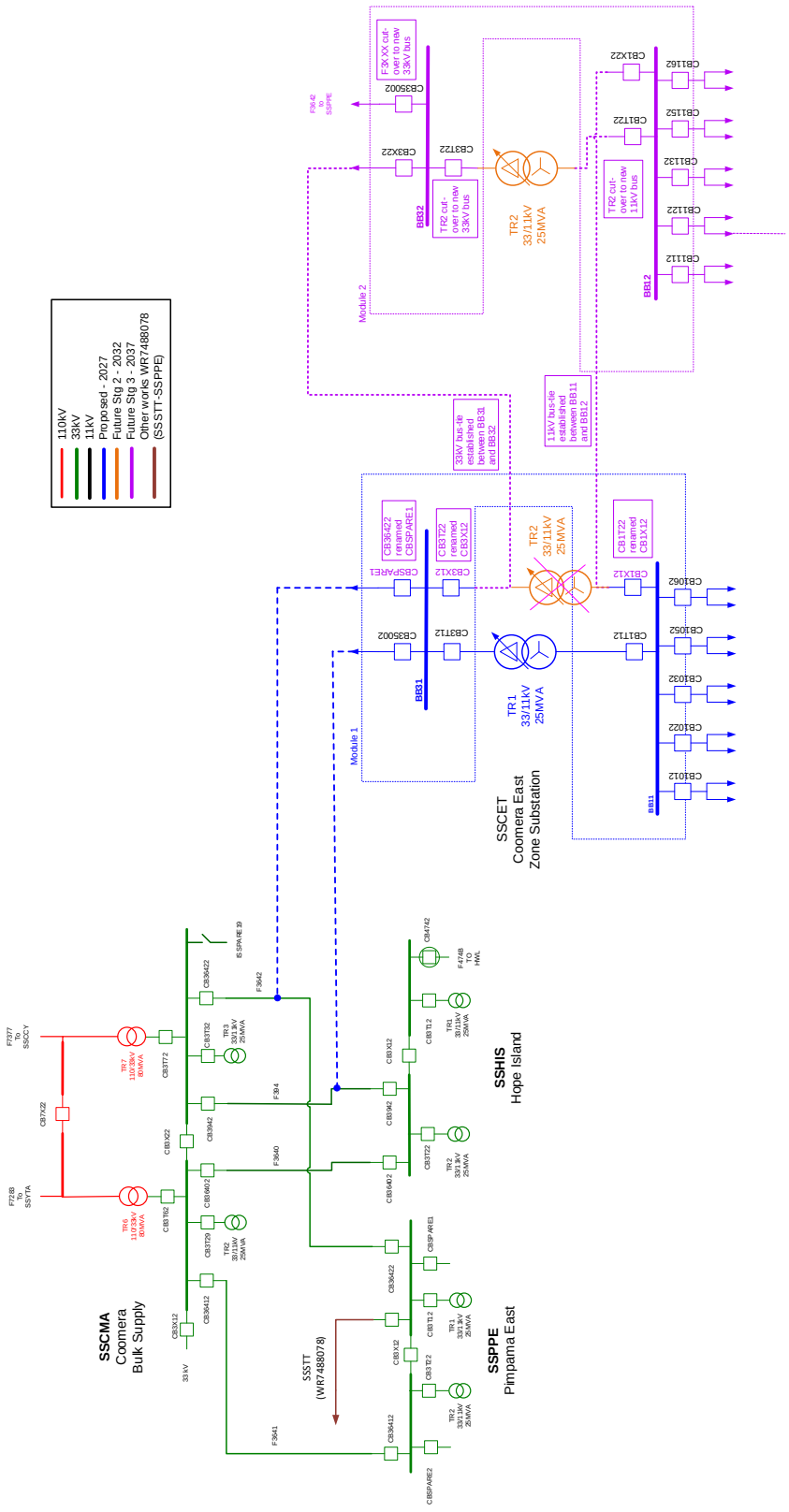


Figure 19: Proposed network arrangement - option B (schematic view)

This option is commercially and technically feasible, can be implemented in the timeframe identified and would address the identified need by providing reliable supply and additional capacity to the Pimpama-Coomera area, which enables Energex to connect new customers to the distribution network and contribute to the reliability requirements stipulated in Energex's Distribution Authority.

The estimated initial capital cost of this option would be $29,033,000. The estimated initial operating costs of this option would be $33,238 per annum. The estimated commissioning date of this option would be 2027.

The estimated construction timetable[2] would be:

- Construction start: 2026
- Commissioning: 2027

The estimated costs comprise the following components:

- financial costs incurred in constructing or providing the credible option (including early engagement on the potential connection requirements and costs of each option) - estimated at $29,033,000 per annum.
- operating and maintenance costs - estimated at $33,238 per annum.
- costs of complying with relevant laws, regulations and administrative requirements – included in the above; and
- costs unique to asset replacement projects or programs – N/A.

There are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline of this option. This is described further in section 4.

3.1.3. Option C: Install a 3rd module at Coomera Zone Substation (3rd module at SSPPE for future stage).

This option would involve:

Establishing a 3rd module and associated switchgear at SSCMA, consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11 kV protection panels, and associated plant, new 1 x 25MVA 33/11kV transformer, establish new 33kV & 11kV tie feeders between both substations and reconfigure existing 11kV feeders at SSPPE and SSCMA to address existing TMU (Target Maximum Utilisation) limitations by 2027.

Future Stage:

- Establishing a 3rd module and associated switchgear at SSPPE, consisting of a single 14.4m modular building with 4 x 33kV CBs, 7 x 11kV CBs, 33kV and 11 kV protection panels, and associated plant, new 1 x 25MVA 33/11kV transformer, establish new 33kV & 11kV tie

[2] Timings shown in this report are indicative and depend on the completion of the RIT-D process.

feeders between both modules and reconfigure existing 11kV feeders at SSPPE and SSCMA by 2034.

Figure 20 provide schematic diagram for Option C.

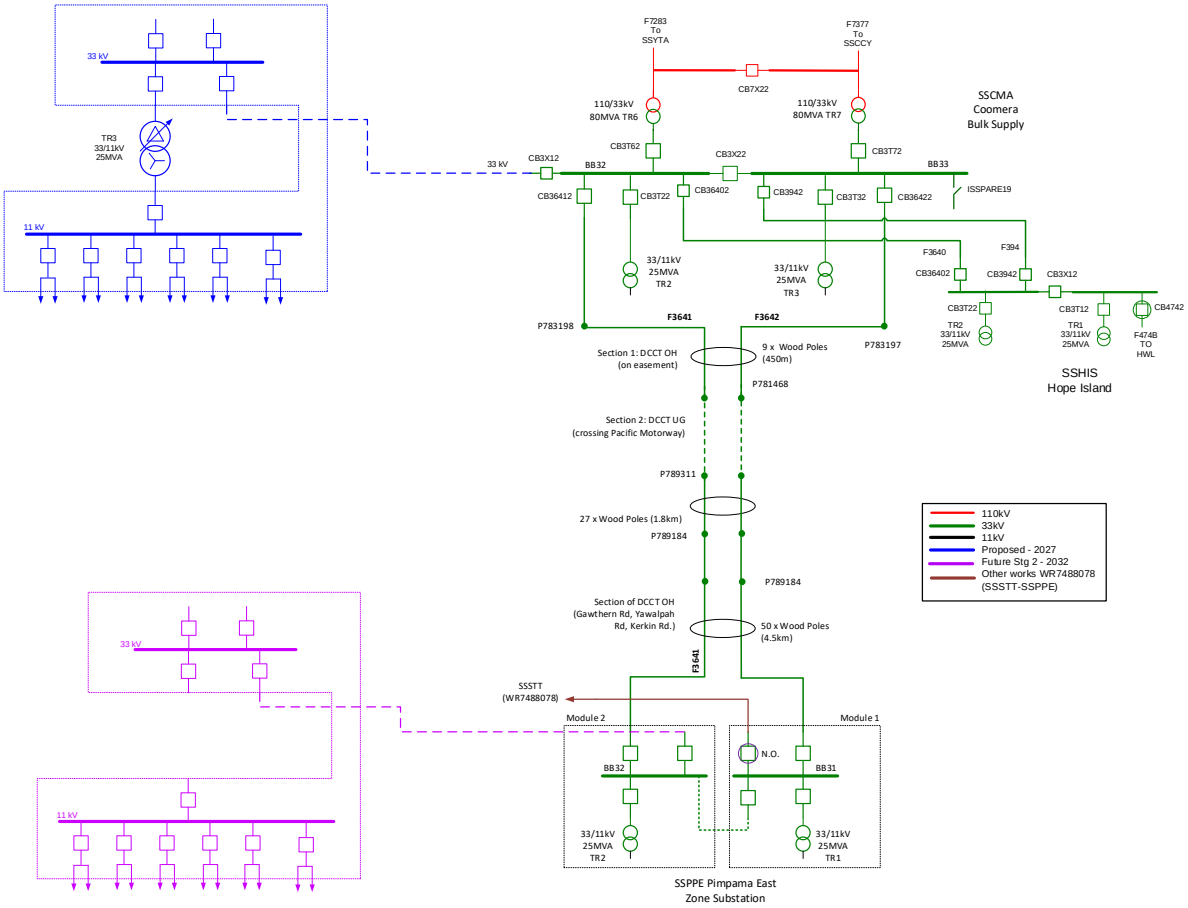


Figure 20: Proposed network arrangement - option C (schematic view)

This option is commercially and technically feasible, can be implemented in the timeframe identified and would address the identified need by providing reliable supply and additional capacity to the Pimpama-Coomera area, which enables Energex to connect new customers to the distribution network and contribute to the reliability requirements stipulated in Energex's Distribution Authority.

The estimated initial capital cost of this option would be $23,764,000. The estimated initial operating costs of this option would be $70,000 per annum. The estimated commissioning date of this option would be 2027.

The estimated construction timetable[3] would be:

[3] Timings shown in this report are indicative and depend on the completion of the RIT-D process.

- Construction start: 2026
- Commissioning: 2027

The estimated costs comprise the following components:

- financial costs incurred in constructing or providing the credible option (including early engagement on the potential connection requirements and costs of each option) - estimated at $23,764,000 per annum.
- operating and maintenance costs - estimated at $70,121 per annum.
- costs of complying with relevant laws, regulations and administrative requirements – included in the above; and
- costs unique to asset replacement projects or programs – N/A.

There are not expected to be any social licence issues that would require additional costs to manage or increase the delivery timeline of this option. This is described further in section 4.

3.1.4. Option D: Network Support Arrangement for load reduction via an external provider

This option is for an external party to provide load reduction, via a network support arrangement, sufficient to meet Energex's ongoing operational requirements (i.e. to mitigate the Load at Risk described in section 1.5.1). This would require a minimum of 3.4 MVA of load reduction at SSCMA and 6.1 MVA of load reduction at SSPPE, in the Summer of 2027/28 and increasing thereafter, when required by Energex (such as during unplanned outages). Please refer to section 2 for more detail.

As an example only, this may involve multiple Battery Energy Storage System (BESS) on multiple 11kV feeders across SSCMA & SSPPE.

Energex is willing to consider other connection arrangements as may be proposed, such as connection at the 11kV substation bus/es rather than on multiple feeders, and other credible solutions which may be identified as part of this RIT-D process such as solutions that reduce the level of load required within the network.

It is anticipated that such a solution could potentially be implemented in the timeframe identified, depending on the solutions proposed and any subsequent commercial negotiations. Such an option must be commercially and technically feasible and address the identified need by:

- Ensuring Energex can meet its reliability performance standards as specified in its Distribution Authority (as described in section 2).
- Being able to be easily expanded to cater for future load growth.
- Mitigate, or at least not worsen, the level of reverse power flow at SSPPE & SSCMA (e.g. generation during the middle of the day will exacerbate reverse power flow levels)

It is expected that any proposed solution for this option would be designed and maintained in accordance with good electricity industry practice, such that a high reliability and availability solution is delivered.

For the purpose of this RIT-D, we encourage proponents to provide costing specific to the proposed solution, but indicative costing for a BESS-type solution is provided to aid proponents: The capital

cost of this option, inclusive of network connection costs, is estimated between $20,000,000 and $40,000,000 and the estimated operating costs of this option would be between $35,000 and $70,000 per annum.

The large variance in estimated costs reflects the range of technically feasible options along with the variance of scope of works required by the different plant types and configurations that might form a proposed solution.

The costs involved in connecting a non-network option are highly dependent on the specifics of the proposal. Connection costs, including any potential costs involved in upgrading the Energex network, will be estimated by the cost benefit analysis.

Any HV connected generation solution would be expected to meet the Energex Standard STNW1175 (Standard for High Voltage EG Connections)[4]. For example, a solution that establishes a new > 5MW inverter-based generator would be capable of supplying additional fault current into the network which can desensitise existing protection and therefore may require upgrade to the protection schemes[5] (such as 11kV bus protection) at SSPPE and/or SSCMA to accommodate.

4. SOCIAL LICENCE AND COMMUNITY ENGAGEMENT

4.1. Social Licence

Energex has not identified any social licence considerations that have affected the identification and selection of credible options to address the identified need.

This is due to proposed network options being located on Energex owned and managed sites. The new SSPPA or SSCET substation sites have been acquired over a decade ago prior to the development of neighbouring properties, and developers have been made aware of Energex's intention of building a substation. Furthermore, the sites are located in commercial/industrial areas (e.g. SSPPA site is next to an on-ramp to the Pacific Motorway on the southern and western boundary and on a major road on the northern boundary). Any new feeders proposed are along road reserve and are expected to be mostly underground construction. In addition, there are also reliability and economic benefits of these options to the local community.

4.2. Community Engagement

As described in section 4.1 above, given the options do not involve impact beyond sites already owned by Energex and planned for future substation use prior to development of neighbouring properties, it is not expected to cause any disruption to the community at large. Community consultations will be held at the early stage of implementation. As a result, we have not identified

[4] Available from: https://www.energex.com.au/__data/assets/pdf_file/0020/1072550/Standard-for-High-Voltage-EG-Connections-2946177.pdf

[5] As per connection requirements under NER Chapter 5.

any community stakeholders who might reasonably be expected to be affected by the development of this project.

As the scope of works for a Network Support Arrangement with an external provider (refer section 3.1.4) is not currently known and will be unique to each non-network option proposed, Energex is not currently able to determine whether there are likely to be any community stakeholders who would be reasonably expected to be affected by the development of the project.

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.

5. INFORMATION TO ASSIST NON-NETWORK PROVIDERS WISHING TO PRESENT ALTERNATIVE POTENTIAL CREDIBLE OPTIONS

Energex engages with customers and demand management providers to develop and implement demand side, non-network and SAPS solutions in accordance with our Industry Engagement Document.[6]

Energex invites written submissions, identifying additional options to address the identified need, from registered participants, AEMO, interested parties, non-network providers and persons registered on Energex's industry engagement register.

Identifying additional options should predominately occur at this stage of the RIT-D process. All submissions that propose new potential credible options should include sufficient technical and financial information to enable Energex to undertake comparative analysis of the proposed solution against other options, to ensure that it addresses the identified need, is technically and commercially viable and is able to be implemented in sufficient time to address the identified need.

The proposals should include, but are not limited to, at least the following:

- Full costs of completed works. This includes the whole of life costs of constructing or providing the credible option, excluding the connection costs.
- Connection costs assumed in the proposed options. Energex will also estimate the connection costs of the proposed options as part of the project assessment.
- Proposed network support contract costs.
- An estimate of the market benefits arising as a consequence of the operation of the non-network option, e.g. as a result of the impact of the non-network option on the operation of the wholesale and/or ancillary services markets.
- Project execution strategy including design, testing and commissioning plans.

[6] Available at: https://www.energex.com.au/manage-your-energy/managing-electricity-demand/industry-engagement

- Engineering network system studies and study reports.
- Verified and approved engineering designs.

Energex will not be legally bound in any way or otherwise obligated to any person who may receive this 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 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 Report.

The selection of any non-network solution to address the identified need will be done in accordance with the Energy Queensland Procurement Policy[7].

Submissions in writing are due by 4pm on 31/03/2026 and should be lodged to demandmanagement@energex.com.au.

[7] Available from: https://www.ergon.com.au/network/contractors/working-with-us/tenders/procurement-and-purchasing-terms

6. COMPLIANCE STATEMENT

This Report complies with the requirements of clause 5.17.4(e) of the NER as demonstrated below:

Requirement	Report Section
(1) a description of the identified need;	**Error! Reference source not found.**
(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;	1, **Error! Reference source not found.**
(3) if available, the relevant annual deferred *augmentation* charge associated with the identified need;	2.1
(4) the technical characteristics of the identified need that a non-network option would be required to deliver, such as: (i) the size of *load* reduction or additional *supply*; (ii) location; (iii) contribution to *power system security* or *reliability*; (iv) contribution to *power system* fault levels as determined under clause 4.6.1; and (v) the operating profile;	1, **Error! Reference source not found.**
(5) a summary of potential credible options to address the identified need, as identified by the RIT-D proponent, including network options and non-network options;	3
(6) for each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on: (i) a technical definition or characteristics of the option; (ii) the estimated construction timetable and commissioning date (where relevant); and (iii) the total indicative cost (including capital and operating costs); and	3
(7) information to assist non-network providers wishing to present alternative potential credible options including details of how to submit a non-network proposal for consideration by the RIT-D proponent.	5

7. APPENDIX A – SAFETY NET TARGETS

Energex has an obligation to meet the Safety Net Targets under its Distribution Authority. The Safety Net targets are defined by the load impacted and the duration of this impact. The table below shows the specific requirements that Energex needs to achieve.

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Distribution Authority - No. D07/98
ENERGEX Limited

SCHEDULE 3

Service Safety Net Targets

Feeder Type	Targets
CBD	• Any interruption in customer supply resulting from an N-1 event at the sub-transmission level is restored within 1 minute
Urban	Following an N-1 event, load not supplied must be: • Less than or equal to 40MVA (16,000 customers) for no more than 30 minutes; • Less than or equal to 12MVA (5,000 customers) for no more than 3 hours; • Less than or equal to 4MVA (1,600 customers) for no more than 8 hours; • Fully Restored after 8 hours
Short Rural	Following an N-1 event, load not supplied must be: • Less than or equal to 40MVA (16,000 customers) for no more than 30 minutes; • Less than or equal to15MVA (6,000 customers) for no more than 4 hours; • Less than or equal to 10MVA (4,000 customers) for no more than 12 hours; • Fully Restored after 12 hours

Notes:
- All modelling and analysis will be benchmarked against 50 POE Loads and based on credible contingencies.
- Outages ≤ 3 minutes in duration excluded from Safety Net Targets.

[as inserted on 05 December 2025]